Individual or group. (39 Responses)
Name (27 Responses)
Organization (27 Responses)
Group Name (12 Responses)
Lead Contact (12 Responses)
Question 1 (36 Responses)
Question 1 Comments (39 Responses)
Question 2 (36 Responses)
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Question 3 (35 Responses)
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Question 4 Comments (39 Responses)
Question 5 (35 Responses)
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Question 7 (35 Responses)
Question 7 Comments (39 Responses)
Question 8 (29 Responses)
Question 8 Comments (39 Responses)

Group
PJM
Albert DiCaprio
Yes
Yes
Yes
Yes
Yes
Yes
Yes

No
Individual
David Proebstel
Clallam County PUD No.1
Yes
No
Clallam County PUD does not employ DR at this time.
Yes
Yes
Yes
Yes
Yes
No
Individual
Keira Kazmerski
Xcel Energy
No
No, it would seem that DR's performance (to the extent they are relied upon for reserves) could have identical consequences as generator trips or load increases. From the document: A DR asset or aggregator that functions according to operating conditions as defined by prior agreements poses no impact to reliability because its impacts are analyzed and assessed in the Operating Plans of the respective Transmission Operator (TOP) and Balancing Authority (BA). The TOP and BA plan in advance to meet system load, including load that is represented or controlled by DR entities. TOPs and Bas have knowledge of all relevant conditions and agreements, and plan operations accordingly for the load to be served with or without contribution from DR. It is not clear how a BA or TOP is going to be able to incorporate DR response into their plans, especially if the DR response is market driven.
No
We would agree that the standards indicate that resources used for reserves have reasonable measures to ensure performance, however, entities would ultimately have to

rely on load shed if any resource (DR or otherwise) cannot fulfill its obligation such that allother options are exhausted.
No
We cannot speak as to how other entities deal with uncertainties around DR in their resource adequacy assessments.
No
We have no way to determine if this statement is true or not.
Yes
No
If DR is used as reserves, then it does allow the BES to serve more load.
Yes
We suggest item b should state “The FMWG should develop proposed concepts for the DR function and continue to monitor DR development and identify if and when DR technology and penetration levels create a unique impact on BES reliability.”
No
Individual
Russ Schneider
Flathead Electric Cooperative, Inc.
Yes
Yes
Yes
Yes
Yes
Strongly agree with this statement DR resources are typically small and well under BES thresholds, often connected a low voltages to local distribution networks outside of FERC jurisdiction.
Yes
Yes
Yes
I thank the team for coming to a reasonable real world conclusion on this one.

Individual
Larry Raczkowski
FirstEnergy Corp
No
FirstEnergy is concerned by the Functional Model Working Group Demand Response Advisory Team (FMDRAT) conclusion that the amount of reliance placed upon Demand Response (DR) in the operations of a reliable system is minimal at best. DR, when used to address system emergencies, is a mandatory commitment to reduce load to maintain reliability due to supply shortage or other real-time system issues and as such, DR resources should be required to demonstrate the same level of responsiveness as a generator.
Yes
However, the alternative measures are not ideal such as dropping of firm load. As the industry places an increased reliance on DR, the commitment for DR to fulfill its obligations should also increase and those expectations should be reinforced through mandatory NERC reliability standards.
Yes
FirstEnergy feels that each entity will apply a discount or percentage factor they are most comfortable with providing. There is no standard requirements between entities as to what factor is used. Since DR is a short-term commitment backed typically by annual contracts there should be standardization around the assumptions made for DR use in the long-term planning horizons.
No
FirstEnergy is not privy to the operational planning activities of other entities. For the FirstEnergy transmission system, DR is a tool available and used in real-time operations by our regional transmission organization. As more importance is placed upon the reliable operation of DR resources, this can become a critical componet in the real-time operations, and PJM long-term planning places significant reliance on DR performance as a capacity resource.
No
FirstEnergy is concerned with the amount of reliance placed upon DR resources in both the planning and operating of a reliable bulk electric system. DR resources should demonstrate the same level of assurdness as conventional generating resources in system planning to achieve an adequate level of reliability. A variety of factors (tariff provisions or regulatory) may be structured to favor DR over traditional generation resources. In doing so, these actions may put the reliability of the transmission and distribution system in jeopardy should customers not wish to participate in DR programs long term due to the volume and duration of load curtailment requests. The commitment from DR resources and its importance to reliable operation of the system would be better reinforced through expectations described in mandatory and enforceable NERC reliability standards.
Yes
FirstEnergy agrees that DR will not expand the capability of the system and is unable to

spontaneously respond to system changes in order to ensure acceptable system performance.
No
As stated above FirstEnergy is concerned with the amount of reliance placed on DR resources in planning and operations of the bulk electric system and that NERC reliability standards serve as a mechanism to better ensure that DR resources respond when called upon. We are also concerned with the lack of a longer term commitment from DR resources and believe NERC reliability standards could drive greater consistency for its implementation.
Individual
Michael Falvo
Independent Electricity System Operator
Yes
Observations 1 and 2 of the FMDRAT's report recognize that at present there does not appear to be any adverse reliability impact to the BES unique to DR resources or new risk for which is no recourse. The nuance of "new" or "unique" risks or impacts has been lost in the wording of Conclusion 1 which may give the impression that DR does not have the potential to impact the reliability of the BES. We suggest modifying Conclusion 1 to be consistent with the Observations and to provide better clarity.
Yes
While we agree with Conclusion 2, we reiterate our comment in response to Q1. In the future, the need may arise for requirements that ensure Balancing Authorities and Resource Planners account for the impacts of the DR resource in an appropriate and consistent manner, thereby minimizing potential risks to BES reliability. The need for these requirements could for example be considered within NERC Project 2009-05 – Resource Adequacy Assessments.
Yes
Also, see our comments in response to Q2.
Yes
We agree that reliability standards are not required to enforce DR compliance with contractual agreements or obligations and that imposing reliability standards to force compliance with commercial agreements would be inappropriate. However the conclusion that DR's minimal reliability impact due to the failure of DR resources to perform as agreed to or as requested may simply be due to its low level of penetration. We suggest amending the second sentence of Conclusion 5 as follows: "At present, there are little or no reliability impacts…" This particular conclusion must be revisited in the future.
Yes
We agree with most of Conclusion 6 but disagree with the point that DR does not expand the system's capability to serve more load. DR is a resource similar to any other supply-side

resource and an entity may choose to utilize that resource in a manner that allows it to serve more load through, for example, peak shaving to allow for growth of baseload. See our further comments in response to Q8.
Yes
See our further comments in response to Q8.
Yes
As indicated previously, we agree that reliability standards obligations are not the appropriate mechanism to enforce compliance with commercial or contractual obligations. We also agree with the recommendations and many of the conclusions of the FMDRAT's report. We want to comment on one of the arguments that leads to these outcomes, as highlighted below. We agree with the suggestion that reliability standards, especially if they are overwhelming, could discourage participation in DR programs, but this should not be a prime consideration on whether or not reliability standards are developed. The FMDRAT's report does not preclude the possibility of creating DR standards in the future if it is determined that DR programs impact reliability. It is reasonable to expect that any entity providing a service that impacts reliability of the BES be held accountable for that service and adhere to standards. Finally, materiality thresholds, or criteria for establishing these thresholds, which may vary by Region, Area or Balancing Authority, will be needed in order to establish applicability of any future reliability standards. Identifying when DR finally does have a significant reliability impact as well as the materiality threshold are issues that will require investigation at a future date.
Individual
Paul Kiernan
New York Independent System Operator
No
The fragment of the conclusion quoted here is extreme in its wording and should be revised. In NYISO's control area, demand response resources are either instructed to respond based on operating procedures or they are dispatched like other supply resources, depending on the market product. The notion of "spontaneous performance" is incongruous with how demand response is deployed in New York. Failure of demand response to perform can have an adverse impact on system reliability when a significant portion of the expected response does not materialize. However, because demand response resources vary in capability, the impact of underperformance of an individual demand response resource may be minimal. Through the design of its demand response programs, the NYISO has implemented procedures to enforce the obligations of demand response, including but not limited to: requesting availability information in advance of an event, reporting of extended periods when a demand response resource is not available, penalties, real-time metering provided to NYISO system operations, and derating of capability for future periods.
Yes
As stated above, the NYISO has implemented procedures to enforce the obligations of

demand response.
Yes
The NYISO uses the derated capability of demand response enrolled in its reliability programs, which is based on historical performance over a capability year, in its studies on resource adequacy and in its long term planning. The NYISO's demand response programs have been in place for over ten years and enrollment continues to grow as demand side resources gain more experience in their ability to respond to a curtailment request, technology improves the automation of response, and demand response aggregators improve their business models to recruit and retain demand response resources.
No
The NYISO, under a variety of scenarios, takes into account the activation of Demand-side Resources as a measure to reduce the load curve to meet an identified reliability need.
Yes
The NYISO believes that higher penetration levels of demand response may warrant the need for a Functional Entity for demand response and that it may be worthwhile for the FMDRAT to reconvene to work towards determining whether NERC or another Functional Entity is responsible for establishing the criteria for different levels of demand response, and whether all demand response providers in the region should be required to comply with reliability standards when the criteria are met or only demand response providers of a certain size.
Yes
At its most basic level, demand response is a change in electric use from normal consumption patterns and as such, it can be considered as a derivative product. Demand response programs for reliability organize the resources that are willing to change their consumption pattern under specific conditions so that the BES can deploy them when traditional supply resources are unable to meet current needs. Having said that, in New York, Demand Response does move in response to dispatch instructions when their reduction is offered for reserves and regulation. These resources are a component to meet the existing ancillary service product standards.
Yes
Yes
The New York ISO (NYISO) appreciates the opportunity to provide comments on the FMDRAT report. The NYISO participated in the development of this report and, with additional comments expressed above, supports its recommendations. This report covers an important issue on the expanding capabilities of demand response to supplement traditional generation and the potential impact that demand response can have on reliability. The NYISO believes that continued review is necessary to establish the levels at which demand response may need to become part of NERC's Functional Model, but it does not believe the addition of new Functional Entity for demand response is necessary at this time.

Individual
John Delucca
Lee County Electric Cooperative
Yes
We concur with the advisory team assessment and recommendation NOT to create an additional Entity/Function.”
Yes
Yes
Yes
Yes
Yes
Yes
We concur with the advisory team assessment and recommendation NOT to create an additional Entity/Function.”
No
Individual
Julie Lux
Westar Energy
Yes
Yes
Yes
Yes
Yes
Yes
Yes

No
Individual
Joe Petaski
Manitoba Hydro
Yes
Yes
Yes
Yes
Yes
Yes
No
Individual
Mark Henry
Texas Reliability Entity
No
No, in the ERCOT Region, certain DR is identified for reserve duty and performs a significant role in Regional criteria, and at times may be a component of meeting Most Severe Single Contingency reserves. Other DR programs are not assigned such duties.
No
No, it is conceivable that in some tight supply conditions, there is no recourse save declaring an emergency and possible firm load shed. In ERCOT, those entities that supply DR as part of operating reserves – perhaps a subset of all DR – are not backed up elsewhere with other reasonable, planned alteratives. DR that is qualified and commits to these reserve duties is expected to deploy.
No
Again, no, at least not for all DR applications. In our Region, the amount of certain DR-supplied operating reserves is at a constant level in long term assessments, based on the amount that our market rules allow for procurement of this service. To the extent that this figure is discounted, that discount appears to be based not on probability of future availability, but instead on performance levels in Regional criteria and historical

participation. Other DR services may be subject to different analysis. I do agree that DR contributions are included in long-term plans.
No
No, for reasons explained above, for those aspects of DR that participate in operating reserves for disturbance recovery at a meaningful level. There are less mature DR applications for which this is a valid conclusion.
No
No. In the ERCOT Region, there are Regional criteria under state regulatory oversight that accomplish this purpose, as well as contractual obligations. Contractual agreements and billing for energy undoubtedly have a role in all aspects of DR arrangements, but DR reserve services merit consideration for Standards due to their impact. Our experience suggests that contractual agreements alone have at times not assured that operational preparation or performance needs were met, although the quality of these contracts also varies. The current situation exposes the BA to operational (and compliance) risk for nonperformance of DR resources at times. There may be a risk that establishing NERC Reliability Standards will discourage participation for immature programs. Some threshold study to define levels of DR participation and roles may provide a basis for focusing on the mature programs with clear operational impacts, as suggested by SPP's comments. Any DR Standard development should reflect stakeholder involvement.
No
No, to the extent that DR is used with operating reserves in some Regions, including automatic underfrequency relay-based deployment, it does move in response to system changes. Certainly not all DR programs function in this way, and it is more limited than generator action.
Yes
Yes, if there is a commitment to further study to establish penetration levels – and perhaps to limit application to certain roles. Within limited roles, certain DR could be considered a candidate for incorporation in the model sooner but it may not fit all Regions. The group is correct that many DR roles may be presently handled contractually or within Regional criteria, but it should continue to monitor as our industry considers a larger role for demand management.
No
Individual
Thad Ness
American Electric Power
No
Taken literally, Conclusion 1 negates the need for, and benefits of, Demand Response as it implies that load could always be shed which obviously is not the preferred course of action if and when other options exist.
No

We believe that it would be better to properly identify those who perform DR-related duties by the creation of the DR functional group rather than placing existing and future DR requirements on existing functional groups whose primary duties do not involve DR. No one can predict what future DR requirements might be created, and without a DR functional group, those new requirements could be misapplied to existing functional groups. While it might be somewhat true that “responsible entities have some measures in place to guard against the possibility that a DR resource does not fulfill its obligations to provide the agreed amount of reserves”, this does not mean that continuing in this manner is the best course of action to take. If no DR entities are created, further requirements would simply end up being absorbed by the existing functional entities, which already burdened with other obligations and requirements. Doing so might be considered appropriate within some regions but not for others, again making it preferable to create DR functional entities which would provide much more consistency across regions. In addition, we are concerned that DR obligations might not be met at all by those who are not currently registered as NERC registered entities yet who are involved in DR activities.
No
While this might be true for existing requirements, future requirements will likely drive the need to create a segmentation of responsibilities. Even if the DR functional entity is not absolutely necessary at this time, future requirements will likely make the need even more apparent. We believe the creation of a DR functional entity will ultimately be necessary, so it seems preferable to create them now rather than simply delaying the inevitable.
No
Again, as stated in our response to Q1, this conclusion if taken literally negates the need for, and benefits of, Demand Response. If DR requirements are indeed needed, there should be a functional entity created to properly represent the work being performed.
No
This has been previously used to infer the apparent similarities between Generation output and markets, however we disagree with this premise as there are many existing GOP requirements which necessitate coordination and communication among these entities. This line of thinking is flawed as it could also be used to advocate that registration not be required for GOPs.
No
We do not believe we can support this argument, as once again, it infers that DR requirements themselves are not needed.
In general, the arguments made by the FMDRAT call into question not only the need to create DR functional entities, but also (and probably unintentionally) the need to have DR at all. As a result, the conclusions reached by the team seem too weak to support the recommendations they ultimately reached. If having DR is indeed beneficial to the reliability of the BES, then functional entities should be created to properly shoulder those responsibilities. We are confident that the FMWG will monitor the situation, but we have concern that pressure for DR related requirements could be mandated faster than a functional entity could be established. We believe that it would be better to properly

identify those who perform DR-related duties by the creation of the DR functional group, rather than place existing and future DR requirements on existing functional groups whose primary duties do not involve DR.
Individual
Scott McGough
Georgia System Operations
Yes
One caveat: Only controllable, dispatchable DR is "instructed" by the operating authority to perform. Economic, dispatchable and non-dispatchable DR is not "instructed" by the operating authority.
Yes
We agree that entities should have some measures in place to guard against the possibility that a DR resource does not fulfill its obligations to provide the agreed amount of reserves. As far as we know, all do.
Yes
Yes
Yes
Yes
Yes
Individual
Laura Lee
Duke Energy
Yes
Yes
Yes
Yes
While Demand Response is an important tool that can be used in the operational time frame, inclusion of an additional DR functional entity will not impact the current roles and responsibilities of the listed entities.

Yes
Yes
Yes
It will be important to reevaluate the conclusions that the recommendations are based on as Demand Response continues to evolve.
Duke Energy finds the Minority Opinion (Section 4) extraneous to the document and issue at hand. The inclusion of Appendix B seems especially irrelevant to this report. For these reasons Duke Energy refrains from commenting on the technical merits of this section.
Group
Pepco Holdings Inc & Affiliates
David Thorne
Yes
Yes
Yes
No
Demand Response is a key component for meeting the resource adequacy requirements in the PJM market. PJM recognizes the key role of Demand Response, and includes DR resources among those which may be offered to meet the resource requirements of Load Serving Entities operating in the PJM system.
Yes
Yes
No
Regional transmission organizations such as PJM routinely rely on DR resources to ensure system reliability, and DR resources are included in the PJM reliability resource market mechanisms. The model should recognize the role of DR resources in providing resource adequacy.
No
Individual
Sylvain Clermont
Hydro-Quebec TransEnergie
Yes

Yes
Yes
Yes
Yes
Yes
Yes
Yes
Individual
Edward Davis
Entergy Services
Yes
As with any component of a plan to respond to system events, the performance of any particular element or resource may or may not provide the releif planned. Contingency plans and mitigation plans should include sufficient diversity to allow for reliability should one step not provide the needed amount of relief. As the FMDRAT report indicates, DR contracts include measures regarding the implication of non-performance when called upon.
Yes
Yes
Yes
Individual
Andrew Z. Pusztai
American Transmission company, LLC

No
The purpose of Operating Reserves is to prevent adverse reliability impacts, such as frequency collapse. Historically, Operating Reserves were added to system operations to protect against such adverse reliability impacts. If DRs are included in Operating Reserves, DRs operation and failure to perform, and the related impact on the reliable operation of the BES should be considered on par with other reserve resources (generation, UFLS, etc.) and, should be subject to reliability requirements to the same extent as other Operating Reserves.
Yes
However, by implementing these measures, ATC believes it is duplicating the effort. This creates a situation such that non-DR resources become responsible for the DRs short comings. Also, consider the situation where the amount of reserves by the DR may not be the same as the non-DR resource.
Yes
Yes
Yes
Yes
Yes
Individual
Jason Snodgrass
Georgia Transmission Corporation
Yes
Yes
Yes
Yes
Yes
Yes

Yes
Individual
Michelle R. D'Antuono
Ingleside Cogeneration LP
Yes
Because Demand Response resources are generally used to supply system reserves or to self dispatch during periods of high electricity prices, there will not be a shock to the local system should it fail to engage as there could be with a potential frequency spike that results when an active generator is suddenly severed from the BES due to a circuit breaker trip.
Yes
The contingency plans that Balancing Authorities and Transmission Operators develop must account for the possibility that a certain percentage of all reserve resources will not respond when called. Therefore there will always be other options available if the DR operator does not reduce load when directed. Furthermore, the DR is under contract to execute their load reduction obligations. There are financial penalties that may be assessed for non-performance (as there generally are for generator non-performance), which would discourage such an action. Also, as more resources compete to participate in Demand Response programs, those with poor track records will lose their bids for future contracts.
Yes
All long term planning entities assume that some fraction of committed resources will not be available during a contingency, whether these are generation or Demand Response resources. This is a practical reflection of the reality that there are many factors that would lead to a Demand Response resource to be unavailable – and consistent with any other resource connected to the BES. Also, as mentioned in the FMDRAT report, many planning entities provide for meeting forecasted load, including that represented by Demand Response. The DR portion is then used in planning for adequate reserves during contingencies.
Yes
As mentioned above, many planning entities provide for meeting forecasted load, including load represented by Demand Response. Planning for reserves, including generation and DR, is then addressed, as mentioned in the report, by applying a discount factor or probability analysis to resources' availability in the resource adequacy assessments. Planning entities apparently have adequate information concerning DR resources currently. Hence, adding a DR function would not change the role or responsibilities of the planning entities.
Yes
This is perhaps the FMDRAT's compelling argument against the need to create Demand Resource Owner and Operator Functional Entity types. Many commercial enterprises will find that the cost of compliance to DR-applicable NERC requirements will override the

revenue they receive by participating in a load reduction program or a reserve market. As stated in the report, there are no NERC standards for Generator Owner/Operators that force compliance with commercial agreements, i.e., a failure to generate to its cleared energy quantity or to provide the needed reserves as procured or requested by the Balancing Authority. The penalties (or lack of payment) to both generators and Demand Response resources provide compliance with no need for imposing reliability standards.
Yes
Perhaps the term “reactive” should be replaced with “non-active” or “passive” to avoid confusion with “reactive power components”. Otherwise, we agree that the operating characteristics of Demand Response resources are very different than generation resources and increase the effective utilization of the BES as described in the report. Absent the incentive to provide responsive reserves, Demand Response would just be part of the forecasted load and the system would be planned and operated accordingly.
Yes
Ingleside Cogneration LP agrees that there is no need to define DR functional entities and include them in the Functional Model because it is not required to maintain an Adequate Level of Reliability of the BES. In addition, as stated in the report, requiring DR resources to adhere to even a limited number of NERC Standards could have a chilling effect on the development of this additional reserve resource that requires no additional system capital investment (as would additional generation reserves). There is no evidence in either operations or planning functions that imposing reliability standards on Demand Ressponse is necessary.
Yes
The White Paper clearly states the predominate reason why we should approach the regulation of Demand Response with caution. Businesses who participate in a load-reduction contract or in responsive reserve markets are economically incented to do so. If they determine that the incremental expense required to comply with NERC’s reliability requirements is too great, they may decide to cease participation in responsive reserve markets and individual contractual arrangements altogether. Since DR resources provide system reserves with no fossil fuel emissions (unlike generation), they provide additional benefits through energy and environmental conservation. Clearly, we do not want to be perceived as impeding progress on these important initiatives. Adding to our unease is the fact that there is no data demonstrating the reliability benefit gained by oversight of Demand Response resources. Secondly, we agree with the FMDRAT’s assessments of the Minority Opinion. As stated in the report, generators are a fundamental part of the integrated power system providing primary products for reliability. Demand Response enhances the capability of the system, primarily by providing an additional source of responsive reserves. However, the integrated system would be planned and operated at an Adequate Level of Reliability without these Demand Response rersources (because they would revert to being only a part of the demand). Hence, there is no substantive reason for including Demand Response in the Functional Model.
Individual

Mike Gentry
Salt River Project
Yes
Yes
Yes
Yes
Yes
Yes
Yes
No
Individual
Patti Metro
National Rural Electric Cooperative Association (NRECA)
Yes
NRECA agrees that DR as described in this report does not pose adverse reliability impacts on the BES.
Yes
NRECA agrees that all responsible entities have some measures in place to guard against the possibility that a DR resource does not fulfill its obligations to provide the agreed amount of reserves. Several examples of reliability standards that specifically address such safe guards are: EOP-001 which requires that “Each Transmission Operator and Balancing Authority needs to develop, maintain, and implement a set of plans to mitigate operating emergencies” with requirement R2.3 specifically addressing “ a set of plans for load shedding”; EOP-002 which requires that Balancing Authorities have capacity and energy plans that include options for curtailing interruptible customers; and EOP-003 which requires Balancing Authorities and Transmission Operators to have load shedding plans.
Yes
The degree of consideration for DR contributions varies greatly among transmission planners and the regions they serve. Those who are planning in RTO regions with capacity and reserve markets likely take a much stronger look at the long-term contributions of DR than in other regions without such markets. DR can be used to help offset capacity

requirements for LSEs and help to meet reserve targets in the markets. Most likely DR contributions in transmission planning are viewed much more conservatively due to the nature of the transmission system operation and the long lead-times associated with the planning and construction of transmission facilities. Peak load projections are the primary driver for transmission planning, and the contributions of DR to that peak load requirement will likely e discounted based on local experiences over time. Whether and to what degree probability analysis is applied to this effort, has little bearing on the question at hand, other than the further out the planning cycle extends, the likelihood DR will see greater discounts (regardless of the discount method of choice).
Yes
NRECA is not aware of any entities that count on DR as a critical component of said entities operational plans.
Yes
NRECA agrees that reliability standards are not required to enforce DR compliance with contractual agreements or obligations. With an approach that includes the possibility of sanctions for non-compliance, there is a significant business risk that would discourage development of demand response.
Yes
NRECA agrees removing load from the BES does not increase the system's capability to serve more load.
Yes
NRECA supports the recommendations include in the DR report specifically that DR functions and any associated functional entities nor be defined and introduced to the Functional Model.
No
Group
PJM Power Providers Group
Glen Thomas
Please see comments in Question 8
Please see comments in Question 8
Please see comments in Question 8
Please see comments in Question 8
Please see comments in Question 8
Please see comments in Question 8
Please see comments in Question 8
Yes
Comments of the PJM Power Providers Group On the Report of the Functional Model Demand Response Advisory Team on Assessing the Need forIntroducing Demand Response Functions and Entities to the NERC Reliability Functional Model I. Introduction On February

10, 2012, the Functional Model Working Group Demand Response Advisory Team ("FMDRAT") issued its Report on Assessing the Need for Introducing Demand Response Functions and Entities to the NERC Reliability Functional Model ("Report"). The FMDRAT assessed the role and reliability impacts of Demand Response ("DR") in the planning and operating horizons. The Report stated six conclusions and two recommendations. Generally, the Report concluded that DR does not impact reliability and specifically stated in Conclusion number five that: "Reliability standards are not required to enforce DR compliance with contractual agreements or obligations. There are little or no reliability impacts caused by the failure of DR resources to perform as agreed to or as requested. Therefore imposing reliability standards to force compliance with commercial agreements would be inappropriate, may not achieve the desired outcome, and in fact may discourage entities from participating in DR programs." (FN1- Conclusion 5, Section 5.0 Conclusions and Recommendations of the FMDRAT Report, February 10, 2012.) The two recommendations stated in the Report were that: 1) DR functions and their associated functional entities not be defined and introduced to the Functional Model at this time, and 2) the Functional Model Working Group ("FMWG") would continue to monitor DR development and identify if and when DR technology and penetration levels create a unique impact on Bulk Electric System ("BES") reliability.(FN2-Section 5.0 Conclusions and Recommendations of the FMDRAT Report, February 10, 2012.) The FMDRAT in the Report noted that prior to submitting the FMDRAT Report to the Standards Committee for acceptance, the FMWG was seeking industry's views on its findings and requested comments as to whether the conclusions and recommendations are agreed to or not. The PJM Power Providers Group ("P3") respectfully submits these comments and does not agree with the Report's conclusions regarding the impact of DR on reliability, nor does P3 agree with the Report recommendations. II. PJM Power Providers Group P3 is a nonprofit corporation dedicated to promoting policies that will allow the PJM Interconnection, LLC ("PJM") region to fulfill the promise of its competitive wholesale electricity markets. Combined, P3 members own over 87,000 megawatts of power generation, own over 51,000 miles of transmission lines, serve nearly 12.2 million customers and employ over 55,000 people in the PJM region. (FN3- The comments contained herein represent the position of P3 as an organization, but not necessarily the views of any particular member with respect to any issue. For more information on P3, visit www.p3powergroup.com) III. Comments P3 appreciates the FMWG's extensive work and commitment to reviewing DR and its role in reliability. P3, however, disagrees with the conclusion that there are little or no reliability impacts caused by the failure of DR resources to perform and with the recommendations of the Report. Rather, P3 agrees with the statement of the Report's Minority Position that DR providers "should bear the same obligations as their generation counterparts and hence should have a comparable set of reliability standards imposed on the DR Owners and Operators." (FN4 - Section 4.0 Minority Position of the FMDRAT Report, February 10, 2012.) While it is debatable whether DR should be relied upon for system security, the reality of the PJM market is that PJM does rely on DR for grid management and treats it as a reliability resource. Given this fact, the NERC report is contrary to the realities in PJM and other organized markets. Although, as P3 continues to maintain, DR is

not a comparable capacity resource with generation, since DR however now makes up a significant amount in the capacity market, if DR does not show up as committed, there is a reliability problem in PJM. DR has grown to be a substantial capacity resource in PJM and rules have needed to be changed to prevent an over reliance on DR to the detriment of reliability. Over 14,000 MWs of DR capacity cleared the 2011 Base Residual Auction ("BRA") which procured capacity for the 2014/15 Delivery Year. (FN5- See PJM 2014/2015 RPM Base Residual Auction Results at http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20110513-2014-15-base-residual-auction-report.ashx p.6.) The BRA is the mechanism used by PJM to obtain the supply resources that it needs to maintain the required level of system reliability. This represented approximately a 50 percent increase in the amount of DR that cleared in the 2010 BRA. (FN6-See id at pgs.4 and 6.) Furthermore, considering the 2011 BRA cleared a total of 149,974.7 MWs,(FN7-See id at p.12.) DR makes up nearly 10% of the total capacity resources committed to PJM for 2014/15. Also noteworthy is that studies performed by PJM suggest that, on a probabilistic basis, at a 10% DR penetration level there would be a 20% probability DR could be called more than 10 times per year. (FN8- PJM Interconnection, L.L.C., Docket No. ER11-2288-000 (December 2, 2010), DR Product Reform Transmittal Letter: p8, figure 3. http://www2.pjm.com/~/media/documents/ferc/2010-filings/20101202-er11-2288-000.ashx.) P3 submits that given the expectation that DR will be called to this extent, it is certainly incorrect to conclude that DR does not materially impact reliability, or to come to the conclusions, as the Report does, that the failure of DR resources to perform as agreed to or as requested causes little or no reliability impact. Equally important is the fact that many DR systems rely on mechanical and communication systems that are owned by a wide variety of entities. For example, many behind-the-meter ("BTM") generators are started and operated to provide the DR that is counted on by PJM. Because these BTM generators are under the control of a variety of entities with a range of managerial and financial wherewithal, it is imperative that these supply resources be required to maintain and test their capabilities periodically to provide a level of assurance that the DR will operate as planned when it is called upon. Historically, DR comprised only a small percentage of the total capacity resources committed to PJM. However, times have changed. As the current data reveals, PJM now relies on DR to be there when it commits to be, and is needed for peak load. The Report is simply incorrect in its conclusions and recommendations. The recommendations of the Report will result in adverse impacts on the BES, and do not amount to a practical or real understanding of how DR operates within the PJM market today. IV. Conclusion Based upon the above-stated comments, P3 respectively urges the Functional Model Working Group not to finalize the Report in its current form as it does not reflect the material role that DR plays in maintaining reliability in PJM and other RTOs. Instead, the working group should develop meaningful reliability criteria that hold DR providers to the same level of accountability as generators. Respectfully submitted, PJM POWER PROVIDERS GROUP By: /s/ Glen Thomas Glen Thomas GT POWER GROUP 1060 First Avenue, Suite 400 King of Prussia, PA 19406 On behalf of PJM Power Providers Group Dated: March 14, 2012
Individual

Don Schmit
Nebraska Public Power District
Yes
No
Group
Electricity Consumers Resource Council (ELCON)
John Hughes
Yes
Yes
Yes
Yes
The FMDRAT should clarify that Conclusion (4) does not imply that (a) DR resources have no or less inherent value, (b) entities do not utilize DR in-part for resource adequacy/planning, or (c) that entities capable of deploying DR in their operational plans should not recognize that value.
Yes
Yes
The FMDRAT should clarify that Conclusion (6) does not imply that (a) DR has no or less value or capability as a capacity resource, operating reserves or regulation service, (b) DR can not be used to more efficiently serve load than existing resources, and (c) DR can not be used to reduce system peaks to avoid the need for additional resources.
Yes
Group
Bonneville Power Administration

Chris Higgins
No
BPA believes that the FMWGroup needs to re-analyze the DR's spontaneous performance to determine if it fits into the NERC functional model, especially in the case where an entity with large amounts of DR of a common mode element vs. substantial loss mode.
Yes
Yes
BPA currently uses a "Planning Reserve Margin" but agrees with the long-term planning industry trend.
Yes
BPA strongly requests clarification from the FMWGroup. BPA believes that the language for Conclusion 4 appears out of the ordinary and is counter to the document the task force published concerning Demand Response Data Availability System (DADS.
Yes
BPA recognizes the need to continue to attain "utility conventional reliability standards" as they are not detached. BPA believes the FMWGroup has not made the case that it is not a reliability issue. BPA also believes the topic is more closely inline with load response, not demand response.
No
BPA's concern is that the FMWGroup is not using the same definition and/or description of the DR that NERC and FERC are using. BPA also recognizes that a modern DR can move spontaneously.
Yes
BPA agrees that with item (a) as to not being defined, introduced or be a part of the functional model at this time. Additionally, BPA agrees with (b) and supports that even though it doesn't need to be a part of the functional model, it still can be used as a tool.
No
Group
Southwest Power Pool Regional Entity
Emily Pennel
No
When reserve margins are high and controllable demand response penetration is low in a region, SPP RE agrees with this conclusion. However, as reserve margins tighten, DR can become more critical for maintaining operating reserves and providing ancillary services which in turn could impact reliability.
No
SPP RE agrees that responsible entities (Balancing Authorities, Transmission Operators and/or Reliability Coordinators) have measures in place should DR fail to fulfill their

obligations. However, the measures are primarily financial or market-based incentives and they do not fall under NERC's responsibility for maintaining BES reliability. While these measures should incent a DR provider to meet their obligations, the application of DR applicable reliability standards, when appropriate, would provide further assurance that DR providers meet their obligations.
No
SPP RE agrees that most entities include DR contributions for long-term planning purposes. However, contract terms for most DR programs are typically less than 5 years, which increases the uncertainty surrounding DR beyond that timeframe. This may exacerbate long-term planning efforts particularly as the reserve margin tightens.
No
Adding a DR functional entity will not change the role of the planning coordinator, resource planner or operations planner for maintaining the reliability of the BES. Adding a DR functional entity would make demand response providers responsible for meeting enforceable reliability standards applicable to their function. SPP RE disagrees with the statement that there are no known entities that count on DR as a critical component of their operational plans since Reliability Coordinators, such as PJM and ERCOT, have controllable Demand Response Programs that they rely on to increase operating reserves when they fall below the required amount or to supply ancillary services. PJM has an Emergency Demand Response program that represents a mandatory commitment to reduce load during system emergencies. ERCOT has two programs that allow load to participate in the ancillary services market and respond to grid emergencies.
No
SPP RE believes that this is true so long as reserve margins are high and the demand response penetration in an area is low. NERC is not responsible for enforcing compliance with contractual agreements, however, they are responsible for maintaining the reliability of the BES through enforceable standards. Should controllable DR penetration reach a level that becomes critical for maintaining reliability, then DR providers should be held accountable for providing their service just as the entities that currently comprise NERC's functional model are. Applicable DR reliability standards would not be used to force compliance with commercial agreements, but would ensure that the DR providers meet their reliability performance obligations.
No
SPP RE agrees that increasing the controllable DR penetration will not increase system capability to serve more load. However, it can be a valuable tool that system operators call on to maintain the reliability of the BES. Not only can DR provide operating reserves and ancillary services, it may provide valuable localized reactive support. Once controllable DR penetration becomes a significant portion of an area's reserves or ancillary services, failing to perform when required may impact reliability. This is why SPP RE recommends that the FMWG conduct a study to determine at what level DR could impact reliability. See response to Question 7.
Yes

While SPP RE agrees with the DR Report Recommendations at this time, we recommend the FMWG consider undertaking a study to establish a threshold or criteria to determine at what point controllable DR technology and penetration levels could impact reliability. As DR reaches this level, it would be just as important for system operators to know what DR resources are available and the rules behind DR use (such as how many times per month they may be used) as it would for them to know what generator capability is available at any time. Examples of standards that may be applicable to DR resources that would give system operators this information are some of the TOP and COM standards.
No
Group
Electric Power Supply Association
Jack Cashin
EPSA cannot answer this question with a definite yes or no as additional factors critically impact how DR is defined and is participating as a resource on the Bulk Electric System. Therefore, please refer to answer to Question #8 for a full explanation of EPSA's perspective on the report, its conclusions and recommendations.
Please refer to answer to Question #8
Please refer to answer to Question #8
Please refer to answer to Question #8
Please refer to answer to Question #8
Please refer to answer to Question #8
Please refer to answer to Question #8
EPSA (Footnote 1) appreciates the opportunity to comment on the Functional Model Demand Response Advisory Team's ("FMDRAT") "Report on Assessing the Need for Introducing Demand Response ("DR") Functions and Entities to the NERC Reliability Functional Model." With demand response increasingly participating as a resource on the electric system, accurately assessing the extent of its role as a reliability resource and any related or necessary NERC registration is timely and necessary. While EPSA can support certain of the FMDRAT report's findings that generating resources and DR resources do not contribute equally to grid reliability for the Bulk Electric System ("BES"), it may be too far a reach to recommend that there be no reliability registration, standards or requirements for DR resources. What the FMDRAT report highlights is increasing concern with mixed messages as to the role that DR plays on the BES and therefore how it should be treated. For instance, the DR Function Report's conclusions are not supported and are in fact repudiated by recent actions and rule implementation by the Federal Energy Regulatory Commission ("FERC" or the "Commission"), in particular issuance of Order No. 745 last year. (Footnote 2) Additionally, DR resources' increased participation as a capacity resource in the organized markets indicates an important role for reliability and assurance of resource adequacy. (Footnote 3) Therefore, DR is currently being integrated in to the marketplace in a manner that reflects some reliability functions. While EPSA does not

believe that DR resources are equal or comparable to generation for reliability, they are increasingly being assumed to function as a network participant as a matter of public policy (whether EPSA agrees or not) and therefore should be accountable for standards, requirements and obligations commensurate with that participation. This view of DR is supported by the statements of DR providers before regulatory venues other than NERC, and at odds with the recommendations of the FMDRAT, as is discussed below. Conflicting assessments of DR's role as a BES resource warrant consideration and analysis by NERC. It's troubling that DR is to be compensated to reflect comparability with generation by rate regulators (i.e., FERC), but then not responsible for comparable reliability obligations for reliability. Further, environmental regulators (i.e., Environmental Protection Agency) are told that because DR based on behind the meter generation is critical during emergencies, it requires loosened environmental restrictions in order to be available as a system emergency unit. These conflicts need to be addressed if greater DR is desired and artificially stimulated by policymakers and therefore would and does represent a network participant on the BES. If the FMDRAT's assessment is correct as to DR's role on the system, then FERC and the Environmental Protection Agency ("EPA") must make concomitant changes in their regulatory treatment of DR. If this does not occur, then it may be incumbent on NERC and the FMDRAT to reassess their findings and therefore conclusions and recommendations here. Based on the implementation of Order No. 745 at FERC, notwithstanding multiple appeals currently pending before the D.C. Circuit, the Commission has determined that "account[ing] for the practical realities of how those markets operate," (Footnote 4) generation and demand resources "[b]oth can have the same effect of balancing supply and demand at the margin either by increasing supply or by decreasing demand." (Footnote 5) Based on that finding, the Commission requires comparable compensation of the Locational Marginal Price ("LMP") for DR resources, which some argue is, in fact, an overpayment due to the inclusion of the foregone retail rate, but, for purposes of the Commission at least at present, represents comparable compensation for a demand side resource which offers similar service to a supply side resource. The premise – refuted by EPSA in comments submitted to FERC during the development of Order No. 745(Footnote 6)– is that DR fills a role in the wholesale bulk power grid which is equal to generation's role in maintaining reliability because it can balance supply and demand. (Footnote 7) This finding, which must be significant as it underpins a required compensation level in every organized wholesale electricity market across the country until the courts rule otherwise, seemingly supports NERC's recognition that achieving the balance of supply and demand is key to reliability: Maintaining the reliability of the North American bulk electric system depends on the complicated and technically sophisticated activities of balancing electricity supply and demand and managing the flow of electricity throughout North America's interconnected networks. These activities require close cooperation among and adherence to minimum standards by all network participants. (Footnote 8) NERC in its Long-Term Reliability Assessment ("LTRA") has also noted the importance of DR contribution as a grid network participant especially in light of the ongoing growth of DR dependence, primarily in organized markets. The LTRA mentions how DR can make up for supply shortfalls as well as asserting that DR is key to coordinating and planning for system reliability. From the LTRA:

The ability to implement Energy Efficiency programs in a relatively short time period provides the industry with another short-term solution to address any anticipated near-term capacity short-falls. Successful integration of Energy Efficiency into resource planning requires close coordination between those responsible for Energy Efficiency and those in bulk system planning to ensure appropriate capacity values are estimated while meeting reliability objectives. (Footnote 9) EPSA highlights that a megawatt of generation can offer attendant services and capabilities that a megawatt of Demand Response cannot, and therefore it is possible that the FMDRAT has found correctly that DR is not as operationally critical or necessary for reliability as generation. This raises concerns, however, surrounding recent findings from FERC as discussed above, as well as possible inconsistencies with certain NERC requirements and findings that DR providers are network participants key to maintaining system reliability. Additionally, and importantly, DR providers themselves have made claims before both FERC and the Environmental Protection Agency ("EPA") which are at odds with the findings of the FMDRAT, and therefore raise serious confusion as to their BES role in light of these contrary messages. These mixed messages from DR providers are outlined below, in responses enumerated based on the FMDRAT Report Review conclusions. The FMDRAT Report Review Conclusions Responding to System Changes The FMDRAT states that a sudden load increase and generator tripping, or DR's spontaneous performance or failure to perform as instructed, do not pose adverse reliability impacts on the BES, and therefore supports the recommendation that DR should not be registered for reliability compliance. This is based on the conclusion that DR is "not an active facility or component like a generator." However, DR providers have asserted that DR is not only on par with generators' physical attributes and abilities to respond to grid management signals, but is indistinguishable from those of generators. From Order No. 745: Viridity states that attempts to distinguish the physical characteristics of generation and demand response ignore bid-based security-constrained economic dispatch as the foundation for LMP and are based on the assumption that the value of load management on the grid is limited to periods when the system is stressed, i.e., traditional "super peak shaving." Viridity states that, while these arguments might have been valid 15 years ago, today competitive markets can offer proactively-managed load control and comparable and non-discriminatory treatment of load-based energy resources. (Footnote 10) Viridity as a DR provider explains that DR can respond comparably to any other resource under times when the bulk-power system is stressed. DR providers state that in times of system stress they indeed play a role in maintaining system reliability. This assertion by DR providers has played a part in establishing the basis upon which FERC equates generation and DR resources to one another with respect to their contribution to reliability, and therefore compensation requirements. While NERC's purview does not extend to issues of compensation or contractual relationships, it is the physical participation in the BES upon which FERC's findings rely. Additionally, several DR providers have urged the Environmental Protection Agency ("EPA") to tailor its environmental regulations to allow DR resources to provide reliability for the BES. A coalition of DR providers (Footnote 11) petitioned the agency regarding its Reconsideration of National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines rulemaking proceeding ("RICE

NESHAPS”), (Footnote 12) stating that changes to the final rule must be considered because DR entities play a key role for transmission operators in times of electric system emergency conditions. The DR providers assert that DR is indeed needed to avoid adverse BES reliability impacts. They state, “Emergency engines participating in emergency DR programs provide a critical service in stabilizing the electric grid on the rare occasions when the grid is about to fail.” (Footnote 13) Further, DR providers note that their operation is based on emergency operation, not driven by cost: “System Operators call emergency DR programs to EEA Alert 2 NERC standards when there is the real potential for blackouts due to insufficient energy supply…regardless of the cost of those resources…” (Footnote 14) Therefore they urge the EPA to extend the allowable hours that stationary internal combustion (RICE) units may operate as emergency units in order to participate in the BES to backup and ensure reliability. These arguments before the EPA raise yet another confounding wrinkle in how DR is to be treated, as DR in some instances is in fact a generation product participating on the system under the guise of a decrease in load. Should, then, DR which is facilitated by additional generation be treated in a different fashion by NERC from DR that is not? EPSA and others, including a major organized market operator,(Footnote 15) believe that DR which is sourced by behind the meter generation should be treated as the resource that it is – generation. To date, FERC has dismissed calls to make such a distinction, but the arguments of DR providers before the EPA underscore that they may well be different resources in terms of their ability to ensure reliability on the system. EPSA argues that if this is the case, then the diesel fuel units are in fact generation and should be held to the same restrictions and requirements. Therefore, this may be an important aspect of DR participation that requires attention and analysis by the FMDRAT and NERC. Long-term planning and Operational Planning In the LTRA, NERC asserts the importance of DR’s contribution to reliability both from the planning and operational perspective. The LTRA also suggests that data from DR resources can be uncertain, especially for long-term planning purposes. Unlike traditional generating resources with many decades of historic data for analysis, the long-term projections of Demand Response resources involve greater forecasting uncertainty. For example, the New England and New York electricity markets integrate large Demand Response programs; however, the long-term availability of these resources remains uncertain. While extremely valuable in planning and operations, less understood attributes of the resources, such as response fatigue or economic-base participation rates must be carefully monitored to assure they do not pose reliability issues in the future. In most cases, forecasting of Demand Response is not performed. (Footnote 16) The FMDRAT Report states that operating entities do not count on DR in their operational plans. The LTRA further asserts that system planners do not have credible information regarding the operational viability of their equipment. However, DR providers have suggested that transmission operators rely significantly on DR in times of emergency. To support this, EnerNOC pointed the EPA to state rules, regulations and resource adequacy planning to demonstrate their key role in upholding reliability. ….[T]he proposed rule would seriously threaten the viability of emergency demand response programs and limit grid operator options to avoid catastrophic losses of power on the electric grid and risk serious damage to electrical infrastructure. Numerous states have formally changed their definition of emergency or otherwise allow the use of emergency engines in emergency DR programs. (Footnote 17) If, as DR providers claim, states have and the EPA should alter environmental regulations and restrictions due to the critical nature of wholesale DR resources,(Footnote 18) the necessary connection is that such resources are critical and therefore should be deemed reliability resources with all attendant responsibilities and obligations. EnerNOC supports this assumption by explaining, “Emergency DR resources are utilized as an important last line of defense against brownouts and blackouts of our nation’s electrical infrastructure.” (Footnote 19) In the context of state actions relying on DR for reliability, the Maryland Public Service Commission (“PSC”) recent experience should be highlighted. In response to warnings by PJM, the regional grid operator, that Maryland could possibly face electric capacity shortfalls as early as 2011-2012, the PSC determined that “the most appropriate and timely response” was to procure “insurance” in the form of customer provided demand response. (Footnote 20) Consequently, the PSC directed the state’s electric utilities to procure DR commitments from Curtailment Service Providers (“CSPs”) such as EnerNOC and several other DR providers. On February 29, 2012, the PSC issued an order approving a settlement agreement between EnerNOC and three electric utilities revising the terms of its commitments, as it did not fulfill the 2011/2012 commitments and addressing prospective contractual terms.(Footnote 21) Other DR providers’ performance is currently under review by the PSC in this proceeding. EPSA Conclusion While the FMDRAT correctly finds that DR is not an active facility or component like a generator, this does not necessarily lead to the conclusions or recommendations included in the DR Function Report. DR is operating increasingly as part of the BES as a matter of policy and there should be standards commensurate with that participation. Additionally, there are complications at play based on whether a DR resource is the product of a true reduction in load or facilitated by behind the meter generation (in which case it is a generation resource which should be bound by the same requirements that apply to other generation). Additionally, the FMDRAT findings cannot stand at NERC if they do not apply fundamentally across regulatory regimes such as FERC and EPA, which have oversight of and impact on the BES. Currently, there are inconsistent explanations of DR’s role on the BES in different policy venues, and therefore inconsistent treatment and requirements. Such distinctions are not theoretical; if DR is a wholesale reliability resource as DR providers claim – either via the energy or capacity markets – then it must be held to the same requirements and obligations as generation resources, or in the least requirements commensurate with its participation. The statements by DR providers suggest that there are real reliability impacts if DR resources do not perform as requested. The FMDRAT report’s conclusions do not reflect that view, which raises grave concerns about the role, responsibilities and obligations of DR providers in relation to their impact on the system and interaction with all BES resources. FOOTNOTES: *[Footnote 1 - EPSA is the national trade association representing competitive power suppliers, including generators and marketers. Competitive suppliers, which, collectively, account for 40 percent of the installed generating capacity in the United States, provide reliable and competitively priced electricity from environmentally responsible facilities serving power markets. Each EPSA member typically operates in four or more NERC regions, and members represent over 700 registered entities in the NERC registry. EPSA seeks to bring the benefits of competition to all power customers. The comments contained in this filing represent the position of EPSA as an organization, but not necessarily the views of any particular member with respect to any issue.] *[Footnote 2 - Demand Response Compensation in Organized Wholesale Energy Markets, Order No. 745, FERC Stats. & Regs. 31,322, on reh’g and clarification, Order No. 745-A, 137 FERC 61,215 (2011), reh’g denied, Order No. 745-B, 138 FERC 61,148 (2012). Petitions for review of Order Nos. 745 and 745-A, filed by numerous parties representing a cross-section of the electricity sector, are now pending before the U.S. Court of Appeals for the District of Columbia Circuit. See Electric Power Supply Association v. FERC, No. 11-1486 (petition for review filed on Dec. 23, 2011, consolidated with Nos. 11-1489, 12-1088, 12-1091 and 12-1093 by orders issued on Dec. 28, 2011, Feb. 13, 2012, and Feb. 15, 2012).] *[Footnote 3 - In PJM, DR represents 10% of the total capacity resources committed for the 2014/2015 delivery period based on the 2011 Base Residual Auction results for the Reliability Pricing Model forward capacity market (“RPM”). See PJM 2014/2015 RPM Base Residual Auction Results at http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20110513-2014-15-base-residual-auction-report.ashx, p. 12.] *[Footnote 4 - - Order No. 745, para 46.] *[Footnote 5 - Order No. 745, para 49.] *[Footnote 6 - Request for Rehearing of the Competitive Supplier Associations, Docket No. RM10-17-001 (filed Apr. 14, 2011), Elec. Power Supply Ass’n v. FERC, Petition for Review, Case No. 11-1489.] *[Footnote 7 - “….demand response has the potential to support system reliability and address resource adequacy and resource management challenges surrounding the unexpected loss of generation. This is because demand response resources can provide quick balancing of the electricity grid. The Commission finds that in the organized wholesale energy markets demand response can balance supply and demand as can generation.” Order No. 745, para 10.] *[Footnote 8 - http://www.nerc.com/docs/docs/blackout/NERC_recommendation_12-technical_edits.pdf.] *[Footnote 9 - http://www.nerc.com/files/2011%20LTRA_Final.pdf, page 15.] *[Footnote 10 - Order No. 745, para 20.] *[Footnote 11 - “Petition for Reconsideration of National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines, Final Rule,” filed by CPower, Inc., EnergyConnect, Inc., EnerNOC, Inc., and Innoventive Power, LLC on May 27, 2010, RIN 2060-AP36, EPA Docket No. OAR-2008-0708, page 2. (“DR Providers Petition”)] *[Footnote 12 - “Comments on Proposed Settlement Agreement,” filed by the Electric Power Supply Association (“EPSA”), the Electric Power Generation Association (“EPGA”), the Independent Power Producers of New York, Inc. (“IPPNY”) and the New England Power Generators Association (“NEPGA”) on February 3, 2012, EPA Docket No. HQ-OGC-2011-1030.] *[Footnote 13 - DR Providers Petition, page 2.] *[Footnote 14 - Id, page 7.] *[Footnote 15 - “DRR that is Behind the Meter Generation (“BTMG”) will not be paid the full LMP, in part, because BTMG is not a demand response reduction in energy, pursuant to Order No. 745, but rather is an incremental increase in Energy behind the meters.” Midwest Independent Transmission System Operator, Inc., Order No. 745 Compliance Filing, Docket No ER11-4337-000 (filed Aug. 19, 2011), Transmittal letter page 5, fn 16.] *[Footnote 16 - NERC 2009 Long-Term Reliability Assessment 2009-2018, p. 19. Available here:

http://www.nerc.com/files/2009_LTRA.pdf. The Report also notes that going forward, “To monitor historical performance of Demand Response, NERC, in coordination with the North American Energy Standards Board (NAESB), is developing the Demand response Availability Data System (DADS) to assess the capability and availability of Demand Response.” page 20.] *[Footnote 17 - EnerNOC, Inc. Comments to the EPA on NESHAP RICE proposed rule) published in the Federal Register March 5, 2009; Vol. 74, No. 42), Docket ID No. EPA-HQ-OAR-2008-0708, page 3. (“EnerNOC EPA Comments”)] *[Footnote 18 - As these state and environmental reliability qualifications appear to be available as part of state resource adequacy plans, and are not confidential as part of commercial agreements, EPSA believes that full consideration of all available resources would add value to the FMDRAT Report.] *[Footnote 19 - EnerNOC EPA comments, page 1.] *[Footnote 20 - Order No. 84715, In the Matter of the Investigation Of the Process and Criteria For Use in the Development of Request for Proposal by the Maryland Investor-Owned Utilities for New Generation to Alleviate Potential Short-term Reliability Problems in the State of Maryland, Case No. 9149 (issued February 28, 2012) (approving Settlement Agreement between EnerNOC, Delmarva Power and Light, Potomac Electric Power Company, Potomac Edison, PSC Staff, and the Office of People’s Counsel).] *[Footnote 21 - Id. at pages 18-20.]
Group
LG&E and KU Services
Brent Ingebrigtson
Yes
Yes
It should be stressed that DR resources are not generally used as reserves in non-market operating areas. DR resources are becoming increasingly significant sources of operating and capacity reserves in ISO/RTO markets. In PJM, DR also provides area regulation services. We agree with the report recommendation that as DR resources take on added significance in such markets, NERC should reevaluate whether some reliability requirements should apply to DR aggregators.
Yes
See response to Question 2
Yes
In many cases, the “contractual agreements or obligations” on DR resources include regulatory (FERC or PSC) approved tariffs, terms and conditions. The potential of additional costs for DR providers related to compliance activities (or potential penalty for non-compliance) could discourage many DR programs, leading to reduced participation. See response to question 2.
Yes
DR is a temporary, voluntary or contractual reduction in load occurring within specified parameters. Entitles responsible for BES reliability must be prepared to take necessary

action to maintain reliability if DR does not perform as planned or if DR performance is within parameters but the reliability threat persists. As noted in the response to question 2, DR provides area regulation in the PJM region.
Yes
Yes
There has been a lack of transparency by the Functional Model Demand Response Advisory Team (FMDRAT) during the final stages of development of this report. It is not clear why the team decided to include a distinct minority position within this report.
Group
Florida Municipal Power Agency
Frank Gaffney
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Under Section 3.2, Observation 2 starts with the sentence: "TOPs or BAs are responsible for managing the load and supply balance in their control areas." This is not true, only the BA does this. Hence, TOP should be struck from Observation 2.
Group
NRG Energy, Inc. ("NRG")
Abraham Silverman
No
NRG strongly disagrees with Conclusion (1), as it appears premised on an outdated assumption that DR will never be a sufficient part of the market to cause an adverse reliability impact on the BES. In fact, many parts of the country are already relying heavily on DR to support system reliability, including the provision of both “active” and “passive” products. This reliance on DR is expected to continue growing in future years as FERC

continues its efforts to integrate DR into the organized and non-organized markets on an equal basis with generation. Further, the Report's finding that there is "recourse" for DR's failure in the form of penalties levied under commercial arrangements or contractual agreements and because of the penalties, reliability standards are not needed to force DR's compliance with its commercial agreements(Report at 3.4.), undercuts the rationale for subjecting generators to the reliability standards. Generation is subjected to the same financial penalties should it not fulfill its commercial and/or contractual arrangements. If because of the penalties, reliability standards are not necessary to achieve the desired DR performance, reliability standards are also not necessary to force generations' compliance with commercial and contractual obligations. If Conclusion (1) is not changed, there will be an irreconcilable conflict between NERC's mission to preserve the reliability of the BES and FERC's mandate that DR providers be able to supply operating reserves and capacity service on an equal basis with conventional generation. If NERC were to exempt all DR providers from registration, regardless of their size or market participation, there would be a major hole in NERC's ability to oversee the reliability of the BES.
No
Because of the lack of operational standards for DR, it is unclear how responsible entities fulfill their obligations to provide reserves. It is clear that from the planning standards, DR is required to be taken into consideration in the planning horizon, but how DR resources are utilized in the operational horizon is a black box. For example, the MOD standards (specifically, MOD-016 through MOD-021) require various registered entities to include DR in their models and forecasts. In fact, the purpose of the standards is described as "to assist in proper real-time operating, Load information related to controllable Demand-Side Management (DSM) programs is needed." As a further example, the planning standard's incorporation of DR is reflected below: • MOD-016 –The standard requires planning authorities and regional reliability organizations to have documentation identifying the scope and details of the actual and forecast demand side management data to be reported for system modeling and reliability analyses. • MOD-021 – Requires LSE's, TP's and Resource Planner's forecasts to document how the Demand and energy effects of DSM programs (such as conservation, time-of-use rates, interruptible Demands, and Direct Control Load Management) are addressed. As discussed in Question 5 and 8, the measures that responsible entities have in place to guard against the failure of DR resources are, by FERC mandate, comparable to the measures that responsible entities have in place to guard against the failure of a generation resource. Each ISO and RTO is under a FERC mandate to allow DR resources to supply energy, capacity and reserve service on an equal basis with generation. However, while the planning standards require the inclusion of DR, there is simply a gap when it comes to the operational standards and the unknown extent to which DR fulfills its obligations. To fill this gap, DR should be subject to requirements along the lines of those set forth in Appendix A to the draft report.
Yes
While DR's contributions may be accounted for in the planning horizon, as discussed in response to Question 2, there is a gap between those plans and the inclusion of DR in the operational horizon. Entities are required to include DR in their planning and forecasting

under the MOD standard, but there is currently no mechanism to hold DR accountable for performing (other than penalties that may occur under commercial and contractual arrangements, which as discussed in response to Questions 1 and 8 are the same penalties faced by generators for non-performance). Resource adequacy procurement, both of generation and demand response, already accounts for a statistical estimate of non-performance. However, NERC and FERC have already concluded that reliability needs dictate that conventional suppliers of resource adequacy services should: (i) have their performance discounted by a statistical estimate of non-performance and (ii) be subject to regulation as registered entities. It is unclear why DR providers should only be subject to (i) and not (ii).
No
No. Existing operational plans are already counting on DR resources as a critical component of their operational plans. In fact, the NERC definition of “non-spinning reserve” is already defined to include DR products. That definition states that “non-spinning reserve” includes “interruptible load that can be removed from the system in a specific time” and that “interruptible load” is defined as “demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment.” Thus, NERC already requires reliability coordinators and LSEs to use DR as one of their tools when encountering a disturbance on the BES. Additionally, several existing NERC standards mandate that RCs and LSEs utilize DR to maintain BES reliability, including MOD-016 through MOD-021 as discussed in response to Question 2 and EOP-001-0, which lists the following as emergency responses: • System energy use – the reduction of the system’s own energy use to a minimum. • Load management - implementation of load management and voltage reductions, if appropriate; • Interruptible and curtailable loads - use of interruptible and curtailable customer load to reduce capacity requirements or to conserve the fuel in short supply; • Load curtailment – a mandatory load curtailment plan to use as a last resort. Additional standards also require the reliance on DR when faced with various operating scenarios, for example: • IRO-006 requires RCs to initiate voluntary load reduction, including DSM, among other mechanisms, when exceeding Interconnection Reliability Operating Limit. • EOP-002-3 – R.6, lists various remedies for the BA to implement should it not comply with the Control Performance and Disturbance Control Standards, including curtailing interruptible load. Further, the different regions include explicit operational language including the activation of DR as a method to return operating systems to normal state. For example, • NYISO lists the activation of Special Case Resources and Emergency Demand Response Programs as possible remedial actions to be implemented in response to an alert state, major emergency or operating reserve deficiency or shortage (*1 NYISO, Manual 15, Emergency Operations Manual at §§ 1.2.2, 2.3, 3.3.1 and 4.4 (November 2011) available at http://www.nyiso.com/public/webdocs/documents/manuals/operations/em_op_mnl.pdf.); • PJM explicitly includes demand resources as load management products and the emergency operations manual states that in response to a load reduction action issued in an emergency situation, demand resources are to reduce load; PJM Manual 18: (*2 PJM Capacity Market (Feb. 23, 2012); PJM Manual 13: Emergency Operations at Attachment G

(Capacity Emergency Matrix) (Jan. 1, 2012)) and • ERCOT relies on DR to maintain system frequency and meet total system capacity, primarily through Load Resources providing responsive reserves and emergency reserve service. Both of these programs have measurement and verification to determine the availability and responsiveness of the reserves. Load Resources providing frequency response with an under frequency relay are an essential tool for grid security in ERCOT. These loads trip instantaneously when frequency dips below their set point. Thus, it is simply inaccurate to suggest the DR resources are not needed for reliability. The RCs, LSEs and ISOs are counting on DR to perform when called upon and as such, DR must be subject to the same reliability standards as generation, otherwise reliability is compromised. As discussed in response to Question 2, there is an inherent gap between the inclusion of DR in the planning horizon but not holding DR accountable through operating standards. The Report's finding that a DR asset poses no impact to reliability because its impacts are analyzed and assessed in the operating plans of the respective TOPs and BAs,((4)Report at 3.1.) ignore the fact that the TOPs and BAs are relying on DR, just as they rely on generation and DR must be held accountable. Again, subjecting DR to the tasks similar to those set forth in Appendix A to the Report will achieve this goal.
No
The Report curiously concludes that because DR is usually arranged through commercial arrangements or contractual agreements and penalties are levied if these obligations are not met, reliability standards are not needed to address the reliability impacts to the BES if DR does not comply with its commercial obligations.(Report at 3.4.) There are several problems with this analysis. First, the premise of the question appears to be that DR resources play no role in preserving the reliability of the BES. As discussed above, this is an incorrect assertion, particularly as DR continues to grow as a portion of total load. Second, financially driven decisions may not be consistent with the reliability of the BES. For example, an entity driven only by financial considerations may (reasonably) elect to pay a financial penalty rather than curtail load and absorb lost opportunity costs when it receives a dispatch from system operators. The economically driven decision may result in stress on the BES as the system operator does not experience the expected drop in load. Third, NERC has previously concluded that economic penalties alone are insufficient to incent generator performance. In most parts of the country, a non-performing DR provider and a non-performing generator would be subject to comparable financial penalties should it not fulfill its commercial and/or contractual arrangements. The FMDRAT's implicit conclusion that NERC registration is necessary to incent generator performance, but is not necessary to incent the performance of DR, is thus illogical and should be reversed. Fourth, NERC registration provides a valuable tool for ensuring that Registered Entities are ready at all times to follow instructions received from grid operators. Requiring DR providers to register would similarly improve the quality of their compliance with reliability instructions from system operators.
No
This appears to be a fundamental misconception in the Report. As discussed in Question 8, many organized markets consider DR to be both "active" and "passive," depending on what

product the DR provider is providing. It is critical that NERC assign appropriate functional responsibilities to DR providers based not on their status as DR providers, but instead based on the service that they are providing to the grid. Further, in each of the organized markets, DR capacity is a 1:1 replacement for thermal generating capacity. Thus, DR is critical to meeting reserve margins. It is impossible to understand how NERC will assure the reliability of the BES if there are no testing, verification of communication protocols, or other registered entity functions applicable to DR.
No
It is critical that NERC input DR functions and their associated functional entities into the functional model immediately. Penetration into parts of the country is already at or near the level of assigned reserve margins, and is growing fast. It is well past time to include DR in the functional model.
Yes
NRG Energy, Inc. ("NRG") appreciates the opportunity to comment on the Functional Model Demand Response Advisory Team's February 10, 2012 Report on Assessing the Need for Introducing Demand Response Functions and Entities to the NERC Reliability Functional Model ("Report"). NRG disagrees with the FMDRAT's majority's refusal to include demand response resources ("DR") in the Functional Model and the majority's finding that DR's "failure to perform as instructed does not pose adverse reliability impacts on the BES for which there is no recourse" (Report at Exe. Summary (1)). The Report curiously concludes that because DR is usually arranged through commercial arrangements or contractual agreements and penalties are levied if these obligations are not met, reliability standards are not needed to force DR's compliance with its commercial agreements (Report at 3.4). However, this conclusion fails to recognize that generation is subjected to the same financial penalties should it not fulfill its commercial and/or contractual arrangements. If because of the penalties, reliability standards are not necessary to achieve the desired DR performance, reliability standards are also not necessary to force generations' compliance with commercial and contractual obligations. DR represents a growing portion of the electric system and the various RTOs and ISOs rely on DR in increasing amounts and capacities. System operators must have assurance that they can rely on DR and financial penalties are simply insufficient to provide such assurance. Further, to the extent DR participates in the same capacity and ancillary services markets as generation, DR should be subject to the same requirements, including reliability standards and, where applicable, availability standards.*3 NRG recognizes the increasing role of DR and that the various regions are relying more heavily on demand resources to meet their reliability needs. For example, FERC's 2011 Assessment of DR & Advanced Metering recognized that the contribution of DR in RTOs and ISOs increased by more than 16 percent from 2009 to 2010 and overall represented 7.0% of the 2010 Peak Demand market:*4 ISO/RTO MWs Percent of 2010 Peak Demand CAISO 2,135 4.5% ERCOT 1,484 2.3% ISO NE 2,116 7.8% MISO 8,663 8.0% NYISO 2,498 7.5% PJM 13,306 10.5% SPP 1,500 3.3% Total 31,702 7.0% Contrary to the FMDRAT majority's view that DR poses no impacts to reliability, the use of DR for reliability is contemplated in NERC's own definition of DR and its existing standards. In fact, the Report itself defines DR as "a temporary change in electricity usage by a Demand

Resource in response to market or reliability conditions" (Report at 3.1). Likewise, the NYISO explicitly recognizes DR as a "reliability program."*6 Additionally, NERC's EOP-001 standard includes both the implementation of load management and the use of interruptible and curtailment customer load to reduce capacity requirements as elements for the development of emergency plans. Additionally, both NERC's ACE and BAL standards contemplate the use of DR to maintain reliability. As the various RTOs/ISOs and FERC have recognized, DR indeed provides reliability benefits. "Economic and Capacity-based demand response clearly provides benefits to regional grid operation and the wholesale market operation. . . . These demand resources provide benefits by providing valuable alternatives to PJM in maintaining operational reliability and in promoting efficient market operations."*7 FERC itself recognized that "demand response has the potential to support system reliability and address resource adequacy[*8] and resource management challenges surrounding the unexpected loss of generation. This is because demand response resources can provide quick balancing of the electricity grid.[*9]" (Order No. 745 at P 10). The various regions include explicit operational language including the activation of DR as a method to return operating systems to normal state. For example, • NYISO lists the activation of Special Case Resources and Emergency Demand Response Programs as possible remedial actions to be implemented in response to an alert state, major emergency or operating reserve deficiency or shortage;*10 • PJM explicitly includes demand resources as load management products and the emergency operations manual states that in response to a load reduction action issued in an emergency situation, demand resources are to reduce load;*11 and • ERCOT relies on DR to maintain system frequency and meet total system capacity, primarily through Load Resources providing responsive reserves and emergency reserve service. Both of these programs have measurement and verification to determine the availability and responsiveness of the reserves. Load Resources providing frequency response with an under frequency relay are an essential tool for grid security in ERCOT. These loads trip instantaneously when frequency dips below their set point. It is simply inaccurate to suggest the DR resources are not needed for reliability. The ISOs are counting on DR to perform when called upon and as such, DR must be subject to the same reliability standards as generation, otherwise reliability is compromised. DR is counted for reliability planning by regional entities and those entities should be able to rely on DR, the same as generation. In its 2010 Annual Report, PJM noted that it was enhancing opportunities for DR to help the system meet future reliability requirements and reported several instances in 2010 when demand resources helped "keep the system sound."*12 FERC Staff itself recognized DR's "significant contributions to balancing supply and demand during system emergencies for several RTOs and ISOs in 2011":*13 - For example, very hot weather during July 2011 in the Eastern U.S. caused demand for electricity to approach record-setting levels. On July 21, the New York Independent System Operator (New York ISO) activated all of its registered demand response in the downstate region (more than 800 MW), and activated more than 2,000 MW of demand resources statewide the following day. - In the PJM Interconnection, L.L.C. (PJM) region, economic (non-emergency) demand response reached a peak reduction of 105 MW in reaction to high prices on July 21. On July 22, PJM activated demand resources in six Mid Atlantic zones, resulting in about 2,400 MW of peak reduction, mostly from emergency demand resources. ISO New England called for 643 MW of demand response on July 22, and estimated that about 663 MW of peak reduction resulted. Extended hot weather and high demand led the Electric Reliability Council of Texas (ERCOT) to activate approximately 1,500 MW of load resources and interruptible resources during a level 2 emergency on August 4, 2011. ERCOT invoked another level 2 emergency on August 24, 2011 and deployed interruptible loads. - ERCOT also called on demand response resources in response to severe cold weather during February 2-3, 2011. A significant number of electric generating facilities in the U.S. Southwest tripped off line, failed to start, or had their available capacity de-rated during the extreme cold weather. On February 2, 2011, a cumulative total of 14,702 MW of generation capacity was unavailable in the ERCOT region. The grid operator responded by dispatching demand response, shedding loads and appealing for voluntary energy conservation by the public. - On February 2 more than 1,000 MW of non-controllable load resources responded to the Texas emergency. About 886 MW of load resources responded within 10 minutes of ERCOT's call. Within the next thirty minutes a scheduling entity contacted ERCOT and shed an additional 140 MW load that was not previously committed. Several demand response providers reduced more load than was committed. - ERCOT also deployed all of its Emergency Interruptible Load Service (EILS), during the February 2-3, 2011 weather event. ERCOT normally procures EILS three times during the year, but decided to obtain supplemental EILS capacity via a one-time April-May solicitation to ensure the availability of demand response resources for the remainder of the year. The various regions rely on DR to maintain their systems and DR should be subject to NERC's reliability standards to assure system operators that using DR will provide reliability. Contrary to the majority's view, mere financial penalties are insufficient to deter DR non-compliance. Additionally, the ISOs and RTOs do not only rely on DR in specific emergency events, but also forgo purchasing other resources in their reliance on DR. For example in PJM's efforts to revise its tariff to compensate DR based not on the resources' likely energy consumption levels during the relevant hour, but on their Peak Load Contribution, i.e., the measure relied upon by PJM to plan for capacity, the Commission noted PJM assertions that "a Capacity DR resource, as opposed to any other load consuming entity, has made a commitment in the RPM auction to met the system reliability requirement, and PJM, in reliance on that commitment, has foregone purchasing other resources."*14 In PJM, as in other regions, DR is participating as an ancillary service that is both compensated and counted on for reliability and is not merely a passive resource. As such, NERC must maintain equivalent and stringent standards in ancillary services markets, regardless of the type of resource (whether DR or generation) providing the service. Further, the various regions are undertaking efforts to even further integrate DR into their markets. ISO-NE and its stakeholders are engaged in modifying their energy and capacity markets to fully integrate demand resources, in compliance with FERC Order No. 745. In so doing, ISO-NE has recognized that "[t]he . . . process for complying with Order No. 745 entails the implementation of rules that will fully integrate demand resources into the energy market. The fully integrated rules are scheduled to become effective as of June 1, 2016."*15 DR is participating on equal footing with generation in capacity and ancillary services markets, is being relied upon by various RTOs and ISOs for reliability planning and as such, should be required to meet comparable performance and reliability standards as generation. The Report distinguishes DR from generation because DR is not an “active facility” (Report at Executive Summary (1)) and, unlike generation, it does not expand the capability of the BES to serve more load (Report at 4). However, DR does just that – it in effect expands the capability of the electric system by allowing demand and supply to be balanced at the margin. In allowing demand response to bid into organized wholesale energy markets, FERC found that such action “expands the amount of resources available to the market, increases competition, helps reduce prices to consumers and enhances reliability.”*16 In many markets the objective is to have active DR respond to dispatch signals just as generators do today. In ISO-NE for example, the current system has a specific amount of dispatchability for DR and through the stakeholder process, ISO-NE is working to have all active DR respond to dispatch signals. Because DR expands the ability of the electric system and actively participates in capacity and ancillary services markets, it is discriminatory to compensate DR for its participation in these markets, but not to hold DR to the same standards as other market participants. Thus, considering that through the various regions efforts to comply with Order 745, the regions are working to hold DR to even more of the same standards as generation, DR must be subject to the same reliability standards as generation. In sum, DR is receiving compensation to perform when needed, the ISOs depend on DR to perform when called upon and as such, DR must be subject to the same reliability standards as generation, otherwise reliability is compromised. In the event the majority rejects these arguments and maintains that the reliability standards should not apply to DR, as the minority suggests, the reliability standards should also not apply to generation (since like DR, generation is subjected to financial penalties should it fail to comply with its commercial and contractual obligations) and the list of NERC Reliability Standards set forth in Appendix B should be removed. ENDNOTES FOR QUESTION 8 *3 - See, e.g., California Independent System Operator Corporation, 127 FERC ¶ 61,298 at PP 58-59 (2009) (granting demand response a temporary exemption from the California ISO’s standard resource adequacy capacity product availability standards, but directing the CAISO to work to end that exemption in a timely manner.) *4 - Federal Energy Regulatory Commission: Assessment of Demand Response & Advanced Metering 2011 Staff Report at 10 (Published Nov. 2011) (“FERC DR Report”) available at http://www.ferc.gov/legal/staff-reports/11-07-11-demand-response.pdf. *5 - Report at 3.1 (“A DR asset or aggregator that functions according to operating conditions as defined by prior agreements poses no impact to reliability because its impacts are analyzed and assess in the Operating Plans of the respective Transmission Operator (TOP) and Balancing Authority (BA).”). *6 - Errata to Annual Report, “NYISO Annual Report on Demand Response Programs,” FERC Docket No. ER01-3001-000 at 4, 9 (filed Jan. 25, 2012) (noting that DR resources in NYISO reliability programs represented 6.4% (2,167 MW) of the 2011 Summer Capability Period peak demand). *7 - Demand Response Compensation in Organized Wholesale Energy Markets, 134 FERC ¶ 61,187 at n.117 (2011) (quoting Senior Vice President of PJM Andrew L. Ott) (“Order No. 745”). *8 - See ISO-RTO Council Report, Harnessing the Power of Demand How RTOs and ISOs Are Integrating Demand Response into Wholesale Electricity Markets at 4, found at http://www.isorto.org/atf/cf/%7B5B4E85C6-7EAC-40A0-8DC3-

003829518EBD%7D/IRC_DR_Report_101607.pdf ("Demand response contributes to maintaining system reliability. Lower electric load when supply is especially tight reduces the likelihood of load shedding. Improvements in reliability mean that many circumstances that otherwise result in forced outages and rolling blackouts are averted, resulting in substantial financial savings . . . ."). *9 - For instance, in ERCOT, on February 26, 2008, through a combination of a sudden loss of thermal generation, drop in power supplied by wind generators, and a quicker-than-expected ramping up of demand, ERCOT found itself short of reserves. The system operator called on all demand response resources, and 1200 MW of Load acting as Resource (LaaRs) responded quickly, bringing ERCOT back into balance. OAK RIDGE NAT'L LAB., NAT'L RENEWABLE ENERGY LAB., TECH. REP. NREL/TP-500-43373, ERCOT EVENT ON FEB. 26, 2008: LESSONS LEARNED (JUL. 2008). *10 - NYISO, Manual 15, Emergency Operations Manual at §§ 1.2.2, 2.3, 3.3.1 and 4.4 (November 2011) available at http://www.nyiso.com/public/webdocs/documents/manuals/operations/em_op_mnl.pdf. *11- PJM Manual 18: PJM Capacity Market (Feb. 23, 2012); PJM Manual 13: Emergency Operations at Attachment G (Capacity Emergency Matrix) (Jan. 1, 2012). *12 - PJM 2010 Annual Report at 6, 11 available at http://pjm.com/about-pjm/who-we-are/~/media/about-pjm/newsroom/2010-annual-report.ashx (noting that "on July 7, for example, PJM asked consumers in the mid-Atlantic region to voluntarily conserve power and issued mandatory load management orders. In late September, the heavy summer loads continued; PJM requested load management in parts of the system on September 23 and 24."). *13 - FERC DR Report at 9-11 (citations omitted). *14 - PJM Interconnection, L.L.C., 137 FERC ¶ 61,108 at P 26 (2011). *15 - ISO-NE and NEPOOL, Price Responsive Demand FCM Conforming Changes, Docket No. ER12-947 at 4 (Jan. 31, 2012). *16 - Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 154 (2008).
Individual
Steven Huber
Public Service Enterprise Group
No
Public Service Electric and Gas Company, PSEG Energy Resources & Trade LLC and PSEG Power LLC ("the PSEG Companies") do not agree with Conclusion (1) that DR's failure to perform does not pose an adverse impact on reliability. First, NERC is wrong in downplaying or minimizing DR's penetration levels. In fact, DR is rapidly becoming a significant source of generation capacity. In PJM, DR represents nearly 8% of the capacity the upcoming delivery year, and nearly 10% in the 2014/2015 forward capacity auction delivery year. NERC's 2011 Long-Term Reliability Assessment has noted that DR increased significantly from 30,000 MW in 2010 to 43,000 MW in 2011. Furthermore, NERC expects DR to increase to 50,000 MW by 2016. This amount represents nearly ½ of the total nuclear capacity in the United States. Clearly, any resource representing such a large fraction of capacity should not be ignored by the Functional Model(FM). Second, DR is considered a resource by Transmission Planners in certain regions. For example, the PJM's Reliability Pricing Model (RPM) forward capacity market allows DR to participate as capacity resources. In the RPM construct

demand resources therefore participate on an equal footing with generation and are considered in the transmission planning process. Furthermore, the RPM structure allows a demand resource provider to offer resources associated with behind-the-meter generation into the RPM. Since DR is considered a substitute for generation by Transmission Planners and Resource Planners and may displace traditional generating units, it meets one of the guiding principles of Version 5 of the FM such that “The Model must be complete, that is that it must include all reliability Tasks and the interrelationships between entities performing them.” Third, the FMDRAT White Paper acknowledges that both generating capacity and DR are resources that participate in operating reserve markets; reserves which would be activated with the sudden loss of generation or a sudden increase in load. Given that generating capacity and DR can both provide operating reserves, they both perform a role in ensuring BES reliability. Since generating capacity is included in the FM, DR, which performs a similar role, should also be included.
No
First, it is not clear which reliability functions the responsible entities discussed in Conclusion (2) are accountable for administering DR resources. There are a number of entities in the NERC functional model that are engaged in planning and reserve requirements. These include the Balancing Authority, Resource Planner, Transmission Planner, Planning Coordinator, and Reliability Coordinator. The interrelationships between the functions are a key component of the FM. For example, the Reliability Functional Model Technical Document notes: “The Generation Operator provides information to the Resource Planner related to generator performance and availability. The Generator Operator provides maintenance schedules, generator status, and AVR status to the Transmission Operator. The Generator Operator receives notification of transmission system problems affecting its generator from the Transmission Operator or Reliability”. It appears that the FMDRAT has only done a cursory assessment of the operational aspect of DR performance for two functions, the Balancing Authority (BA) and Transmission Operation (TOP), and concluded that load can be served with or without DR. The PSEG Companies believe that the FMDRAT may not have adequately evaluated the interrelationships between DR and the other reliability functions. Second, the conclusion that other entities specified in the current FM have measures in place to resolve the issues caused by the failure of DR to meet its obligations is unsupported. Resource Planners ensure sufficient resources are planned so that the failure of any resource (generator or DR) is addressed and reliability is maintained. Furthermore, Reliability Standard BAL-002 ensures that the Balancing Authority must have access to a Contingency Reserve to respond to disturbances. So Conclusion (2) is already addressed in NERC standards and therefore is not relevant to the discussion of whether DR entities should be added to the Functional Model. Rather, NERC should consider to what extent DR replaces other capacity resources, and whether that replacement has a potential long-term reliability impact. As noted in the Minority Views section of the White Paper, as more and more DR is included in the dispatch stack and in the planning and operating horizon, fewer real generation resources are required to meet the aggregate load obligations on the grid. In fact, in PJM studies, DR is assumed to available to the full extent that it is committed as a capacity resource. However,

this performance standard is not necessarily always achieved. For example, in the July 20, 2011 load management event in PJM only about 91% of the MW of DR called upon was actually delivered in certain regions. Nor is there any assurance that any “extra” resources to address potential non-compliance by DR providers will be obtained through the RPM construct. In fact, the RPM procedures used for procuring sufficient capacity resources to meet the one-day in ten-year loss of load expectation do not impose any obligation to procure capacity resources to offset the non-performance of DR capacity resources. Moreover, even if RPM does sometimes acquire more resources than the minimal amount needed to meet the reliability expectation for a one-day in ten-year loss of load probability, there is no assurance provided that a sufficient level of extra resources to offset non-performance by DR (which comprises up to 15% of the all capacity resources for at least one transmission zone in Delivery Year 2014/2015) will be available. Accordingly, it cannot be assumed that there will be extra capacity resources needed to offset non-performance by DR capacity resources for the purpose of capacity adequacy. Moreover, NERC should explain the basis for its conclusion that “DR’s spontaneous performance or failure to perform as instructed does not pose adverse reliability impacts on the BES for which there is no recourse.” How can it be assured, for example, given the longer-term implications of DR replacing generation resources, that there will be extra generation capacity available to make up for DR that does not show up when it is being relied upon to do so?
No
While resource adequacy assessments are not embedded in NERC’s standards, they are performed by NERC to fulfill its obligations per Section 215 (g) of the Federal Power Act. Our responses to Question 1 and Question 2 demonstrate that DR has a reliability role in the operation of the BES, and should be considered in planning for BES reliability. The determination of whether a reliability function for DR should be included in the FM is not solely dependent upon how DR is modeled for resource adequacy assessment treatment. The purpose of the FM is to ensure there are no gaps in the operation, or performance of reliability tasks anywhere in the BES. The determination as to whether a function should be included in the FM should be based on the reliability effects arising from that particular function as well as the interrelationships between the specific function and the other reliability tasks in the FM. As noted in our comments on Conclusion (2), PSEG does not believe the FMDRAT effectively evaluated these interrelationships. Additionally, NERC recently created the NERC Demand Response Availability Data System (DADS) to collect information on the performance of DR. Explaining the need for DADS, NERC also clearly laid out the importance of DR to reliability with the following statement. “In order for NERC to carry out its responsibility to ensure the reliability of the North America bulk power system, NERC must be able to: evaluate and understand the benefits of demand response and it impact on reliability; quantify the performance of demand-side resources; and assess the overall characteristics of demand response as it relates to bulk power system planning and operations.” These statements suggest that NERC is looking at DR as an important component of the BES which should not be overlooked by summarily dismissing DR from inclusion in the FM. They also reinforce the fact that FMDART’s conclusion is at odds with overall NERC policy and direction on this issue.

No
Please see the responses to Questions 1 and 2.
No
Conclusion (5) presupposes that DR is merely a contractual agreement which has no impact on reliability. As discussed earlier, PSEG believes that the performance of DR can be expected to have an impact on the reliability of the BES. Moreover, NERC already includes generator owners and purchasing-selling entities in the FM. These parties enter into commercial arrangements with an understanding that such arrangements may have a host of associated regulatory requirements which may be borne solely by the owner of the asset or shared through the contractual agreement. A generation asset owner is subject to reliability as well as environmental standards, and contractual arrangements may be subject to FERC or state utility commission oversight. In these cases the generation asset owner assesses the costs for compliance with those requirements and factors them into its business plan. Historically, NERC has not considered the effects of these regulatory requirements when specifying reliability requirements for generators. Demand response providers should be treated no differently. To the extent that NERC is relying on indeterminate compliance with these commercial arrangements as the basis for concluding that DR has no impact on reliability, these arrangements should be periodically audited so that there can be some degree of comfort obtained that the arrangements are not wholly illusory. The responsible entities should, at a minimum, have procedures in place to assure that the claimed commercial relationships actually exist for the entire duration of the term for which the DR facility is being claimed as a capacity resource. In addition, adequate standards need to be in place to measure and verify performance and seasonally capability.
No
DR should not be considered purely a derivative product of the power system. In PJM and in the ISO-NE, DR participates in the forward capacity markets (in PJM the forward capacity market is also known as Reliability Pricing Model or RPM). In those markets, DR is paid the same locational capacity price as generators in the same delivery zone. In the NYISO, DR also participates in the capacity market and receives the same capacity payments as traditional generators. Since capacity is one of the principal components of a reliable BES, DR must be considered more than a derivative component or reactive product of the BES. In addition, this finding ignores that in many cases DR is not just like generation, it is generation. For instance, the Midwest ISO recently indicated that it believes more than half of the total DR on its system is actually behind the meter generation(1). The instant White Paper provides absolutely no basis to distinguish between the reliability impact of a generating unit operated as a capacity resource based on the unit's location in relationship to a meter. (1) See Comments of Midwest ISO, Docket ID number EPA-HQ-OGC-2011-1030, filed February 2, 2012, p. 2 "Currently, MISO has approximately 8,000 MW of Load Modifying Resources to meet resource adequacy requirements. Of that 8,000 MW, over 4,500 MW of such Resources are from behind-the-meter generation including many internal combustion engines." (available at http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OGC-2011-1030-0012.)

No
NERC should include DR in the next version of the Functional Model. NERC should consider including functions for Demand Response Ownership and Demand Response Operation.
No
Individual
Matthew F. Goldberg
ISO-NE
No
As DR is treated comparably to other resources (e.g., as capacity resource), DR may have similiar impacts.
Yes
The relevance of this conclusion to the question presented (i.e., the establishment of DR functional model category) is not clear.
Yes
No
The conclusion contains two separate assertions: (i) whether DR is a critical component of operational plans, and (ii) an additional DR functional entity will not change the current role or responsibility of the PC, RP, or operational planner. Depending on the area, DR may be important part of operational planning. For instance, FERC has recently observed that: "The reliability of ISO-NE's power grid hinges on the fact that its market participants, whether providing generation or demand response, respond timely and accurately to ISO-NE dispatch instructions." See Final Audit Report, PA11-20, at page 30 (1/13/12). The question of whether the roles/responsibilities of PCs, RPs might be modified depends on the role/responsibility assigned to DR. (Operational Planner is not a Functional Model entity)
No
As DR is treated comparably to other resources, it is not clear why Standards that are crafted to ensure an adequate level of reliability would necessarily discourage entities from participating in DR programs. Moreover, the presence of contractual agreements is not necessarily a dispositive factor about the need for Functional Model categorization.
No
As DR is treated comparably to other resources, it may have the impacts for which appropriate Reliability Standards would support acceptable performance.
Yes
The FMWG should continue to convene and monitor this issue.
Yes
The Team should continue to meet, because as DR becomes more prevalent and provides services on a comparable basis as other resources (e.g., generation capacity), the question of establishing DR in the Functional Model needs to continue to be considered.

Individual
Brett Holland
Kansas City Power & Light
Yes
Yes
Yes
Although the FMDRAT report did not specifically refer to the NERC Reliability Standards, the MOD-018-0 Standard requires Entities to include consideration of uncertainties of load projections and energy to meet load obligations and the treatment of those uncertainties for the purpose of assuring those uncertainties are reflected properly in reliability assessments. The conclusion that was drawn by the FMDRAT is consistent with the application of this standard.
Yes
NERC Reliability Standards MOD-019-0.1 and MOD-020-0 require Entities to provide forecasted and actual demand response actions for the express purpose of performing and understanding the reliability impact of the effects of demand response actions.
Yes
Yes
The FMDRAT has captured the essence of what the NERC Reliability Standards represent in MOD Standards 018 through 020 regarding demand response actions and effects and have drawn appropriate and reasonable conclusions.
Yes
No
Individual
H. Steven Myers
ERCOT ISO
Yes
Yes
Yes
Yes

Yes
Yes
Yes
Individual
Maggy Powell
Constellation Energy Commodities Group
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
We appreciate the efforts of the Advisory Team in developing this report. The team delves into a number of the aspects unique to demand response (DR). We agree that the facts and analysis to date do not present reliability concerns that warrant including DR in the functional model. It is critical that the NERC perspective on DR focus on reliability. A number of DR aspects concern market mechanisms and economic products that are important to understanding DR, but not necessarily relevant to its role in reliability. Varying types of DR products and services, variations in markets across regions, as well as the similarities and differences between DR and generation all warrant careful consideration before deciding whether action is needed. Until there is a substantiated reliability issue before NERC and stakeholders, DR should not be added to the functional model. While this report begins to look at the reliability aspects of DR, to further clarify the role of DR in reliability the team should further vet a number of other issues. We believe that a greater understanding of the aspects below will strengthen the conclusions of the FMDRAT report, improve the understanding of DR and its role relative to reliability and clarify the boundary

between reliability and market mechanisms. Identified below are issues and questions to consider: • Because DR assists in reducing load, in the event of an SOL or IROL exceedance, DR could be used to bring the system back within its operating limits. The Report should explain why the use of DR is different from the use of load shedding to address SOL or IROL exceedances, to illustrate that DR need not be brought within the scope of the Reliability Standards. • The Report addresses normal operational circumstances, explaining that "in operational planning, there are no known entities that count on DR as a critical component of their operational plans." This should also address planning for emergency circumstances to demonstrate that DR would not have an important reliability role in responding to system emergencies. For example, the Report should explain why a DR provider would not need to be one of the entities bound to comply with Reliability Coordinator, Transmission Operator, or Balancing Authority directives during a system emergency in the same manner as Load-Serving Entities, Distribution Providers, Generator Operators and the like. • The Report explains that the contractual obligations of DRs are sufficient to drive the appropriate behavior, stating that "having commercial arrangements and compensation/penalty mechanisms in place to govern their contractual obligations would suffice to drive DR to achieve the desired behavior." The Report should also address situations where DR could be operationally useful but is, for some reason, contractually unavailable. As written, the Report suggests that there are no circumstances in which a system operator would need to call upon DR when DR would be unavailable. Are those circumstances unlikely to exist given the contracts under which DR operates? Or does load-shedding and generator dispatch provide faster relief such that incorporating DR within the NERC Functional Model would provide no reliability purpose because DR would not be used by system operators in responding to reliability concerns? • The Report states that "all responsible entities have some measures in place to guard against the possibility that a DR resource does not fulfill its obligations to provide the agreed amount of reserves" and that "compared to sudden load increase and generator tripping, DR's spontaneous performance or failure to perform as instructed does not pose adverse reliability impacts on the BES for which there is no recourse." This should explain how, under the existing Reliability Standards, responsible entities are already required to plan for the unavailability of DR. The current discussion does not reference the current planning Standards, but should do so to demonstrate that the measures in place to guard against improper DR action are already mandatory and do not, therefore, need to be addressed through new Standards or Requirements specific to DR. • The Report should be placed in the wider context of avoiding unnecessary regulatory burdens on DR. DR provides critical environmental and cost-savings benefits because it reduces the need for new generation capacity and helps avoid the use of high-emission, high-cost generation during peak load periods (e.g. peak-shaving). For these reasons, among others, the Commission is working to increase the use of DR across the United States. See, for example, the Commission's 2010 National Action Plan on Demand Response. Making DR a new NERC functional type and imposing Reliability Standards compliance obligations on DR providers could discourage the wider use of demand response and, as a result, prevent the country from achieving the environmental and cost-saving benefits DR can provide. • Also worth consideration is that, currently, much

of DR operates at the distribution level and the majority of DR participants are connected below the threshold of the BES and thus not subject to NERC registration. When analyzing the role of demand response in reliability, it is critical to establish criteria that clearly distinguish the types and thresholds of DR relevant to reliability. Thank you for the opportunity to comment.
Individual
Charles Yeung
Southwest Power Pool - RTO
Yes
No
The FMDRAT report does not provide sufficient evidence to support this conclusion. Supporting data, in the form of survey results or other research, would have assisted in validating this conclusion. While I do believe the statement is true, the report offers nothing to support it.
No
Again, the FMDRAT report does not provide sufficient evidence to support this conclusion. Supporting data, in the form of survey results or other research, would have assisted in validating this conclusion. While I do believe the statement is true, the report offers nothing to support it.
No
While we are not aware of any entities that count on DR as a critical component of their operational plans, the FMDRAT report does not provide any supporting evidence/data to collaborate the conclusion.
Yes
Yes
Providing the use of the term ‘reactive’ is meant to imply that DR is a responsive component of the power system. When I first saw ther term ‘reactive’ I was confused by the possibility that some reference was being made to reactive power. I would suggest changing this term to ‘responsive’ or some other term to eliminate the possibility of confusion
Yes
Yes
Group
ACES Power Marketing Standards Collaborators
Jason Marshall
Yes

To answer this question, the drafting team needs to define what is meant by demand response. NERC has defined Demand-Side Management which essentially includes all activities designed to limit load or influence the amount and timing of use. As a result, Demand-Side Management would include direct load control (i.e. air conditioners, hot water heaters), interruptible customers (i.e. primarily industrial customers), real-time pricing (i.e. some utilities have established these programs outside of an organized market) and demand response programs as established in many markets and that are designed to respond to economical signals. If the drafting team intended to focus on demand response that is incentivized by economic signals, then we agree that it does not pose an adverse reliability impact. If traditional load control and interruptible customers were intended to be included, then it is possible for an adverse reliability impact to occur because these are generally counted upon for capacity and energy deficient situations. Of course, in those situations, load shed would still be available. Our selection of the "Yes" checkbox assumes the drafting was truly focued on demond response that is incentivized by economic signals.
Yes
Our answer assumes that demand response is only that part of Demand-Side Management that responds to economic signals. We agree that all responsible entities either have measures in place or are required to have other measures by the NERC standards should demand response not provide agreed upon reserves. For example, BAs and TOPs are required to have load shedding plans per EOP-003. BAs must also have capacity and energy energy plans per EOP-002. They may also have interruptible customers and direct load control. In addition, FERC has provided a very clear signal to demand reponse providers that they must comply with tariffs. A demand response provider entered into a settlement agreement with FERC for failing to comply with PJM's tariff by not responding to calls for reserves(133 FERC ¶ 61,089). The settlement calls for the entity to pay a civil penalty of $500,000 and disgorge $2,258,127 of profits and interest. There was also personal liability of $50,000 in a related settlement (138 FERC ¶ 61,018).
Yes
Most transmission planners and planning authorities either currently have or are developing methodologies to consider demand response via probabilistic analysis. The remainder of transmission planners and planning coordinators do not count on the performance of demand response and plan to serve this load. While demand response programs are still developing, this is a conservative but reasonable approach. Other transmission planners and planning coordinators in areas with more mature demand response programs, do consider the probability of demand response performance. In general, transmission planners and planning coordinators plan to serve all other forms of demand-side management such as load-control and interruptible customers because these are intended for emergency operations.
Yes
We know of no entities that count on demand response in operational planning. Furthermore, even if BAs and TOPs did count on demand response, they are required to have other plans in place per EOP-002 and EOP-003.

Yes
Reliability standards cannot impede markets and tariffs. Applying reliability standards to demand response at this stage of development will likely impede its development. Risks of sanctions will add one additional significant business risk that certainly does discourage development of demand response.
Yes
It is certainly straight forward that removing load from the BES does not increase its capability to serve load.
Yes
Given that DR is still not mature, this seems like a very reasonable approach.
No
Group
ACES Power Marketing Standards Collaborators
Jason Marshall
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