414 Nicollet Mall
Minneapolis, Minnesota 55401

September 1, 2011

—Via Electronic Filing—

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 Seventh Place East, Suite 350
St. Paul, MN 55101-2147

RE: COMPLIANCE FILING
DEMAND RESPONSE – POTENTIAL OPPORTUNITIES TO PARTNER WITH ARCS
DOCKET NO. E-999/CI-09-1449

CUSTOMER BUYBACK PROGRAM
DOCKET NO. E-002/M-11-588

Dear Dr. Haar:

Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company") submits the attached Compliance Filing in response to the following Minnesota Public Utilities Commission's (the "Commission") Orders:

- ORDER PROHIBITING BIDDING OF DEMAND RESPONSE INTO ORGANIZED MARKETS BY AGGREGATORS OF RETAIL CUSTOMERS AND REQUIRING FURTHER FILINGS BY UTILITIES, Docket No. E999/CI-09-1449 (May 18, 2010);
- ORDER REQUIRING FURTHER FILINGS BY UTILITIES, Docket No. E999/CI-09-1449 (February 8, 2011); and,
- ORDER ACCEPTING XCEL ENERGY'S FINAL REPORT AND CANCELLATION OF ITS CUSTOMER BUYBACK PROGRAM, Docket No. E002/M-11-588 (August 8, 2011).

Together, these Orders require the Company to submit the following by September 1, 2011:

1) A report on ARC operations in the wholesale markets operated by the Midwest Independent Transmission System Operator, Inc. ("MISO") and in the wholesale markets operated by other independent system operators and regional

transmission organizations, focusing specifically on the impact of Aggregators of Retail Customers ("ARC") operations on prices, reliability, nonparticipating customers, utility operations, and utility-operated demand response programs;
2) Comments on the ability to expand demand response options through contracts with third parties in order to achieve demand response potential;
3) Potential replacement program options for the Company's Customer Buyback Program; and
4) A report on the tariff and program changes that each utility believes would be necessary to accommodate ARC operations in Minnesota.

Pursuant to Minn. Stat. § 216.17, subd. 3, we have electronically filed this document, and copies have been served on the parties on the attached service lists.

Please contact Carolyn Brouillard at carolyn.s.brouillard@xcelenergy.com or (612) 330-5571 or me at (612) 330-6270 or allen.krug@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

/s/

ALLEN D. KRUG
MANAGING DIRECTOR
REGULATORY ADMINISTRATION

Enclosures
c: Service Lists

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Ellen Anderson	Chair
David C. Boyd	Commissioner
J. Dennis O'Brien	Commissioner
Phyllis A. Reha	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF AN INVESTIGATION OF WHETHER THE COMMISSION SHOULD TAKE ACTION ON DEMAND RESPONSE BID DIRECTLY INTO THE MISO MARKETS BY AGGREGATORS OF RETAIL CUSTOMERS (ARCS) UNDER FERC ORDERS 719 AND 719-A

DOCKET NO. E999/CI-09-1449

COMPLIANCE FILING

IN THE MATTER OF NORTHERN STATES POWER COMPANY'S REQUEST TO ACCEPT ITS FINAL COMPLIANCE REPORT AND CANCEL THE CUSTOMER BUYBACK PROGRAM

DOCKET NO. E002/M-11-588

COMPLIANCE FILING

INTRODUCTION

Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company") submits to the Minnesota Public Utilities Commission ("Commission") these Compliance Filings. These Compliance Filings address the requirements of the Commission's Orders dated May 18, 2010 and February 8, 2011 in Docket No. E999/CI-09-1449, and the Commission's Order dated August 8, 2011 in Docket No. E002/M-11-588, which include:

- A report on Aggregators of Retail Customers ("ARC") operations in the wholesale markets operated by Midwest Independent Transmission System Operator, Inc. ("MISO") and in the wholesale markets operated by other independent system operators and regional transmission organizations, focusing specifically on the impact of ARC operations on prices, reliability, nonparticipating customers, utility operations, and utility-operated demand response programs;
- Comments on the ability to expand demand response options through contracts with third parties in order to achieve demand response potential;

- Potential replacement program options for the Company's Customer Buyback Program; and
- A report on the tariff and program changes that each utility believes would be necessary to accommodate ARC operations in Minnesota.

PROCEDURAL BACKGROUND

Federal Energy Regulatory Commission ("FERC") Order No. 719, as amended,[1] sought to improve the operation of organized wholesale electric power markets such as the MISO wholesale regional energy and Ancillary Services Market. Among other things, Order No. 719 modified market rules to allow ARCs to bid demand response resources from retail customers into a RTO's wholesale market, unless the relevant electric retail regulatory authority prohibited such action.

Order No. 719 directed RTOs and ISOs, like MISO, to submit compliance filings to modify their tariffs to, among other things, allow the operation of ARCs within their region, or demonstrate that their existing tariff and market design satisfied the requirements of Order No. 719.[2] MISO submitted its compliance filing on April 28, 2009, but FERC has not yet accepted the ARC-related aspects of MISO's Order No. 719 compliance filing.[3]

In January 2010, the Commission opened this Docket to determine how it should exercise its responsibilities under Order No. 719. After receiving comments from interested parties, on May 18, 2010, the Commission issued an ORDER PROHIBITING BIDDING OF DEMAND RESPONSE INTO ORGANIZED MARKETS BY AGGREGATORS OF RETAIL CUSTOMERS AND REQUIRING FURTHER FILINGS BY UTILITIES. This Order took the following actions:

- Prohibited the demand response resources of the retail customers of Minnesota's investor-owned utilities from being bid into organized markets by non-utility aggregators of retail customers;
- Required utilities to file by June 28, 2010 descriptions of their demand response programs;

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[1] *Wholesale Competition in Regions with Organized Electric Markets,* Order No. 719, FERC Stats. & Regs. ¶ 31,281, 73 FR 61,400 (Oct. 28, 2008); *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292, 74 FR 37,776 (July 29, 2009); *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719-B, 129 FERC ¶ 61,252 (Dec. 17, 2009) (collectively, "Order No. 719")

[2] On May 15, 2011, FERC issued a separate, but related Order No. 745. Order No. 745 states that a demand response resource must be compensated for the service it provides to the energy market at the market price for energy, referred to as the locational marginal price. *Demand Response Compensation in Organized Wholesale Electric Markets,* Order No. 745, FERC Stats. & Regs. ¶ 61,187 (May 15, 2011) (hereinafter "Order No. 745").

[3] *See* FERC Docket No. ER09-1049. On October 21, 2010, FERC issued an order accepting the RTO/ISO governance requirements of Order No. 719, but "reserve[d] for judgment in a separate order Midwest ISO's compliance with all remaining Order No. 719 requirements." *Midwest Independent Transmission System Operator, Inc.*, 133 FERC ¶ 61,068 at 1 (Oct. 21, 2010).

- Required utilities to file by September 1, 2011 a report on ARC operations and a report on tariff and program changes; and
- Established the criteria to evaluate proposals for pilot projects designed to explore the potential for ARC and other third-party providers to increase levels of demand response in Minnesota.

On June 28, 2010, we filed a description of our demand response programs, which was followed by comments from interested parties on August 25, 2010. The Company filed Reply Comments on September 23, 2010.

The Commission met on January 27, 2011 to consider the utilities' filings and related comments and replies. On February 8, 2011 the Commission issued an Order requiring the investor-owned utilities to file comments by September 1, 2011 on the ability to expand demand response options through contracts with third parties in order to achieve demand response potential.

The Commission's August 8, 2011 Order in this Docket and Docket No. E002/M-11-588 directed the Company to include in its September 1, 2011 compliance filing potential replacement program options for its Customer Buyback program that it intends to further develop with its customers and the Department.[4]

COMPLIANCE FILINGS

In the attached document and in the narrative below we provide the required information in compliance with the above-referenced Commission Orders.

A. Report on ARC Operations in the Wholesale Markets

We provide this report as Attachment A to this filing. We respectfully request that the Commission accept this report as fulfillment of our requirement under Order Point 3a of the Commission's May 18, 2010 Order in this Docket.

We partnered with Interstate Power and Light, Otter Tail Power, and Minnesota Power to contract a consultant to prepare the report. We note that the consultant was unable to provide direct and definitive answers to the Commission's questions due to a lack of publicly-available data, and the inability to distinguish between ARCs and other demand response participants in wholesale markets.

However, through the use of existing studies and interviews with several experts, the consultant was able to make general statements about the impact of demand response on prices, reliability, non-participating customers, utility operations, and utility-

[4] This program was referenced in our June 28, 2010 Compliance Filing as the Peak Day Partners program.

operated demand response programs, drawing inferences about the impacts of ARCs where possible.

The report concludes that there is general consensus that demand response reduces wholesale energy prices, at least in the short-run, and can help reduce prices for capacity and ancillary services. Through participation in capacity and ancillary service markets, demand response can also help satisfy adequacy, reliability and security requirements. Demand response's impact on non-participating customers is largely dependent on the compensation scheme approved; non-participants are generally protected if demand response providers are paid a rate that does not increase the overall cost of the demand response program.

The authors found varying impacts of demand response and ARCs on utility operations between the ISOs and RTOs, ranging from minimal to substantial impacts. The impacts can be substantial where utilities must provide customer data and event data to the ARCs. The largest impact on utility-operated demand response programs is likely customer confusion due to multiple demand response offerings available to customers from various parties. Finally, to the extent demand response has affected prices and the other metrics in deregulated states, ARCs are likely the primary drivers of those effects since they constitute the bulk of the demand response resources in those markets.

B. Comments on the Ability to Expand Demand Response Options

Below we provide discussion of the definition and objectives of demand response, our existing demand response programs, and comments on expanding demand response options through the use of third party contracts.

1. Definition of Demand Response

As adopted in Order No. 719, FERC defines demand response as "a reduction in the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy."[5]

For purposes of this filing, we will limit our definition of demand response to reductions in electricity consumption in response to incentive payments. This definition refers to demand response resources that are dispatchable, meaning that the customer is directed by a utility or other entity to reduce energy consumption.

[5] 18 C.F.R. § 35.28(b)(4) (2010).

Examples of dispatchable demand response resource programs are direct load control programs, such as air conditioner cycling programs, and interruptible rate programs, where participating customers reduce load when called on to do so, in exchange for lower rates (i.e. discounts on firm service rates). Non-dispatchable demand response resources include predetermined time-varying rates and market-based dynamic rate programs, which allow customers to choose whether, when, and how much to change consumption as retail rates change.

2. *Demand Response Objectives*

National policy seeks to foster more competition in wholesale electricity markets and lower the cost of meeting the country's electricity needs. Demand response bid directly into the wholesale energy market may play a role in fostering competition in wholesale electricity markets by providing more supply options, allowing new entrants to the market, and decreasing the total physical generation capacity needed to serve load.

To increase the amount of demand response nationwide, the Energy Independence and Security Act of 2007 directed FERC to conduct a national assessment of demand response potential and develop a National Action Plan and implementation proposal to achieve the potential.[6] Additionally, to facilitate the growth of demand response in the market, FERC instituted several reforms through Orders No. 719 and 745 designed to allow demand response resources greater access to wholesale markets and to enable demand response to be paid market values for the services it provides.

However, FERC has acknowledged that state regulatory agencies have ultimate authority over whether to allow ARC participation and retain their authority to regulate their respective demand response retail tariffs.

From the Company's perspective, the overarching objective of demand response programs is to reduce peak demand, which has the benefit of: (1) reducing peak demand can lower costs by lowering peak generation capacity requirements and avoiding high energy costs; and, (2) demand reductions can help preserve system reliability during periods of high demand, thereby helping to avoid brownouts and other reliability issues. In summary, by managing load, utilities and other load-serving entities can better manage costs by reducing expensive peak generation capacity that is needed less than one percent of hours each year and by reducing exposure to high market energy prices during those times.

[6] FERC's *National Action Plan on Demand Response*, Docket No. AD09-10 (June 17, 2010).

3. Xcel Energy Demand Response Programs

As discussed in our June 28, 2010 Compliance Filing in this Docket, we have a portfolio of long-running demand response programs for our business and residential customers, including:

- Electric Rate Savings (interruptible rate program);
- Saver's Switch for Business (direct load control); and
- Residential Saver's Switch (direct load control).

We rely on these programs primarily to reduce the highest system peaks that occur on hot, humid summer weekdays. Because demand response resources are netted from our load forecast before applying the planning reserve margin, demand response programs help us meet our planning reserve requirement.

For each of these programs we aggregate the participating retail customers and represent those customers as one program in the wholesale market. By registering these programs as "Load Modifying Resources" in MISO's resource adequacy construct (Module E), they can count towards our planning reserve requirement.

We also use our demand response, in aggregate (as tiers), in MISO's Day-Ahead and Real-Time markets. For instance, when our load forecast is high, we decrement the amount of energy we purchase in the Day-Ahead market by the amount of interruptible load we expect to call in real time. This action reduces the exposure to high day-ahead and real-time prices, and reduces both the per MW and total cost of energy purchased for our customers. These savings are reflected in the Fuel Clause Adjustment and are passed through to all customers.

In Minnesota, we have approximately 855 MW of controllable capacity under these programs with approximately 350,000 participating customers, representing 12.2 percent of peak load. On the Northern States Power system as a whole, we have over 1,000 MW of controllable load.[7] This supports FERC's National Assessment of Demand Response Potential, which shows that Minnesota has a higher level of existing demand response than most states, particularly in regards to participation in interruptible tariffs.[8]

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[7] The Northern States Power system includes the Northern States Power Company, a Minnesota corporation and Northern States Power, a Wisconsin company operating companies.

[8] A National Assessment of Demand Response Potential, June 2009, available at http://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf

As such, the identified demand response potential for Minnesota represents a much smaller incremental gain than is possible in other states, with much of the potential coming from direct load control and dynamic pricing.

a. Electric Rate Savings

Within the Electric Rate Savings program, we offer a number of sub-programs to provide additional flexibility and options to customers. For example, we offer the Peak-Controlled Rates program to business customers that can control at least 50 kW of their electric demand during the summer months.[9] The program includes time-of-day and non-time-of-day pricing versions. It also includes Tier 1 and Tier 2 sub-groups. The tiered sub-groups each have different performance requirements, such as maximum annual interruption hours and contract lengths.

The rate incentives (discounts) also vary by the amount of load relief actually available during summer peak times as a share of the total amount of discounted controllable load.[10] Interruptible discounts for retail customers are specified in retail service tariffs and do not directly represent market prices. Participating customers can save on their average monthly demand charges in exchange for reducing demand during required control periods; customers receive the discount regardless of whether their load is called for control in a given year.

We also offer an additional energy rate discount to qualifying Peak-Controlled Rates customers. The *Tier 1 Energy Controlled Rates Rider* requires additional interruption hours (i.e. outside of peak control hours) when energy supply prices are high, but reliability is not necessarily threatened. There is also a similar program, *Energy Controlled Service (Non-Demand Metered)*, for non-demand metered customers to control dual-fuel space heating loads and water heating loads in exchange for a lower energy rate.

Finally, until recently, we also offered the *Peak Day Partners* program, which provided participating customers with an option to commit to reduce load by at least 500 kW in return for a market-based incentive payment determined the day before the Company expected to need the load relief.[11] This load relief was intended to be ad hoc, voluntary, and market price-driven, and used only as a last resource to avoid an emergency that would result in firm load shed.

We sought to cancel this program because we had not needed to use the program since the summer of 2001, due to the availability of wholesale energy resources in the

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[9] Customers typically receive one hour notice of a control period.
[10] The total amount of discounted load is based on a customer's maximum monthly billing demand
[11] This program is also known as the Customer Buyback Program.

MISO energy market. Also, wholesale market prices under the MISO Day 2 and Ancillary Services markets have been low relative to what retail customers seem to require in order to induce them to voluntarily curtail end use loads. The Commission approved our request to cancel the program in August 2011, but directed the Company to propose a replacement program.[12]

b. Saver's Switch

Saver's Switch is a direct load control program for residential and business customers used to reduce demand from air conditioners on hot, humid summer weekdays when system loads are likely to reach peak conditions. Residential customers may also enroll their electric water heaters for year-round control. Participating customers receive an air conditioning discount during the four summer months of June through September, regardless of actual load control activity. Residential customers receive a 15 percent discount on their electric energy and fuel cost charges, and business customers receive a monthly discount of $5 per ton of air conditioning load.

In summary, the Company has a large and robust demand response portfolio that provides options for residential and business customers to receive discounts when they agree to reduce demand during control periods. We have historically deployed these resources predominantly to manage our peak load, which provides the majority of cost savings. The net savings produced by these programs are passed on to our retail customers.

4. Expanding Demand Response

As noted above, FERC, as guided by national policy, is interested in expanding demand response as a way to improve the competitiveness of the wholesale energy markets and lower costs. Specifically, we have seen a movement to expand options for customers and third parties to participate in federally-regulated energy markets and increase the incentives available to demand response providers through the federally regulated wholesale markets.

This can take the form of customers or ARCs offering demand resources into the wholesale market, where they compete against generation or supply-side resources to provide energy or operating reserves. When offers are accepted, the participant receives a market-based payment for the lowered demand, or for the provision of ancillary services. Failure to reduce load can result in financial penalties. In addition, demand response can provide capacity in RTO run resource adequacy constructs.

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12 See the Commission's August 8, 2011Order in this Docket and Docket No. E002/M-11-588; see also, section 3, below.

Demand response activity in wholesale markets (as opposed to retail demand response managed by the utility or load serving entity) is most prevalent in deregulated states or markets that encompass a single state, such as NY ISO and PJM. In these markets, customers that do not have access to a regulated retail demand response tariff are paid directly by the wholesale market for demand response. In the wholesale market, the cost of paying demand response is allocated to market participants according to the FERC-approved wholesale market tariff, which differs in each market. This is in contrast to Minnesota, which is not deregulated and where customers have access to Commission-approved retail demand response tariffs.

In Minnesota, under the approved retail demand response tariffs, the cost of retail demand response discounts are appropriately distributed to all retail customers, which recognizes its beneficial role as an alternate capacity resource. For MISO demand response programs, the recovery and allocation process is yet to be defined or approved, which presents the risk that some of the cost savings provided by Minnesota customers will be more widely distributed throughout the MISO region to the detriment of Minnesota customers.

These differences in regulatory structure and historical demand response activity, as well as current resource needs, make it difficult and perhaps risky to directly import programs from other states and regions and rely on the wholesale markets to subsidize and incentivize a robust demand response program. Therefore, we are cautious about pursuing demand response programs that are wholly federally regulated and subsidized through the wholesale markets.

Over 12 percent of our system peak is already controllable and we expect to have sufficient capacity available over at least the next five years. We believe that it would not be cost-effective to further expand our existing demand response programs in the short term, either through utility promotions or contracts with third parties.

When we compare the cost of adding demand response, assuming current interruptible rate discounts, against the cost of adding alternatives, like a new combustion turbine, it may be more cost-effective for our customers for us to add the physical generation than to expand our current programs. We believe that any new program should be cost competitive against new generation additions and provide benefits to non-participating customers.

Further, expanding our current programs would not serve FERC's objective of improving the competitiveness of the wholesale energy and operating reserve markets, since our current interruptible rate programs do not allow customers (or third parties representing those customers) to participate directly in those markets.

However, we believe there is growing interest from customers, third parties and state and federal regulatory agencies to expand options for customers and third parties to participate directly in wholesale energy markets. We are willing to explore possible ways for our customers, through third party contracts or otherwise, to have more access to the demand response products offered by MISO. But, we believe there are several issues that need to be addressed before any new demand response pilot or program could be implemented. We discuss these issues in Section D below.

C. Replacement Program Options for Customer Buyback Program

In approving our request to cancel the Customer Buyback program, the Commission directed us to identify potential replacement program options that we could develop with our customers and the Minnesota Department of Commerce – Division of Energy Resources (the "Department").

One of the distinguishing features of the Customer Buyback program was that the incentive for reducing load was largely based on wholesale market prices. As noted above, we are willing to explore program options that would provide more opportunity for customers to respond to market opportunities, which would preserve that market-based feature.

We envision that these program options may include opportunities to contract with third parties to implement or market the program. Therefore, we believe that replacement program options and options to expand demand response through third party contracts can be considered together and may result in a single program that satisfies both objectives. As a result, the issues discussed below are also relevant when considering replacement program options.

D. Report on Tariff and Program Changes

Whether or not tariff and program changes would be necessary to accommodate ARC operations in Minnesota largely depends on what role the ARCs would play and what existing program offerings are affected. For example, tariff changes may be unnecessary if ARCs were to operate as our agents in promoting existing demand response programs.

However, as discussed above, we believe that it would not be beneficial to expand our existing programs in the short-term, and agree with the Commission that any new demand response activity should not replace existing activity or simply change the identity of the person performing them.[13]

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[13] See page 7, Order Point 5(e) of the Commission's May 18, 2010 Order in Docket No. E999/CI-09-1449.

The direct participation of ARCs in the wholesale markets as envisioned by FERC would require ARCs to coordinate operations through utilities under an approved retail tariff. This is a fundamental requirement that is needed to avoid double-counting of demand response, cost-shifting, and potential harm to customers. Without coordination and oversight through a retail tariff, ARC operations may make system planning more difficult and provide the opportunity for rate discrimination.[14]

In developing any ARC-related program, the following issues would need to be evaluated and addressed:

- Administration,
- Infrastructure, and
- Payment and recovery.

We provide a discussion of these issues below.

1. Administration

To administer a program that would allow an ARC full access to MISO's market, it would be necessary to manage:

- Development of new and revised tariffs;
- Confirmation that customer demand response is not double counted;[15]
- Registration of ARC resources with the MISO market;
- ARC offers into the market;
- Issues related to developing the correct communication and metering;
- Settlements;
- Billing;
- Retail revenue and cost accounting; and
- Reporting requirements.

2. Infrastructure

The Company would have to establish ARC-specific infrastructure for metering, communication infrastructure, and billing and settlement. For example, currently all retail customers are billed through the Company's Customer Resource System ("CRS").

[14] See our February 16, 2010 Comments in this Docket for a more complete discussion of the potential impacts of allowing ARC operations in Minnesota.
[15] Double-counting could occur if customers were allowed to be on one of our existing demand response tariffs as well as any new program

In order to accommodate the billing needs of a market-based demand response program, we would need to implement system changes in the back-office to properly account for the MISO feeds, which would essentially create a second bill statement to participating customers. Necessary changes in our CRS and Power Billing System ("PBS") could range from $250,000 to over $1 million depending on the complexity and scope of the project.

3. Payment and Recovery

A new retail tariff would have to address how to transfer payments from the wholesale market to the participating customers, while protecting non-participating customers from charges from the wholesale market. The proposal would also have to address recovery of the associated infrastructure and increased administration costs.

Protection from excessive demand response payments could be improved by subtracting from those payments the applicable retail energy rate applied to the forgone energy. For example, as noted in the report provided as Attachment A to this filing, Indiana has approved direct pass-through of MISO settlements minus the marginal forgone retail rate plus a five percent administrative fee.

We acknowledge that the issues discussed above, in addition to other issues that we have not yet identified, could potentially be barriers to implementing a demand response program that allows customers, or ARCs, or both to participate more directly in the wholesale energy market. However, we believe that our involvement is critical not only to avoid double-counting and other customer equity issues, but to preserve our important relationship with our customers.

CONCLUSION

Xcel Energy respectfully requests that the Commission accept our Compliance Filings. Should the Commission determine that customers or ARCs or both should have the opportunity to participate directly in wholesale energy markets, we will work with parties to develop a pilot program concept that addresses the issues raised herein. We look forward to continuing the discussion on how demand response can best meet the needs and objectives of all critical stakeholders.

Dated: September 1, 2011

Northern States Power Company,
a Minnesota corporation

RESPECTFULLY SUBMITTED,

/s/

By: ______________________________

ALLEN D. KRUG
MANAGING DIRECTOR
REGULATORY ADMINISTRATION

Aggregators of Retail Customers: Impacts on RTO Markets

Xcel Energy, Minnesota Power, Otter Tail Power, Interstate Power & Light

The Mendota Group, LLC
Olivine, Inc.

August 30, 2011

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Executive Summary

The following report responds to the Minnesota Public Utilities Commission's request that Minnesota utilities provide a report on the effects of aggregators of retail customers (ARCs) on prices, reliability, nonparticipating customers, utility operations, and utility-administered demand response programs in the wholesale markets operated by the Midwest Independent Transmission System Operator (MISO) and other independent system operators. The report concludes that such a request cannot be readily answered with publicly available data and that, if such data were available, definitive conclusions would still be difficult to draw.

Therefore, the following report instead seeks to review existing studies, supplemented by discussions and interviews with RTO, utility and regulatory representatives, other experts, and ARCs in an effort to thoroughly examine the issues the PUC raises. This review also did not lead to definitive conclusions but does help to define the role ARCs play in Northeastern RTOs and the effects demand response generally has on prices, reliability and nonparticipants. The study contends that demand response does indeed reduce prices and increase reliability. Although the extent to which ARCs are responsible for these benefits is not possible to determine with available information, it is reasonable to conclude that they are partially responsible to the extent that they increase participation in demand response activities. Current experience indicates that ARCs' greatest contributions are to increased reliability given their more active participation in capacity markets.

This study determined that MISO has no existing ARC participation and so current comparisons between MISO and other RTOs are not possible. However, it can be inferred that ARC participation in MISO markets would alter the current demand response program structure and require meaningful changes to existing Midwest utility demand response programs, which are primarily interruptible programs serving residential, commercial and industrial customers.

Minnesota's very robust levels of utility demand response participation make the state an attractive target for ARCs because there exists a base of customers who are very familiar with demand response. This high level of demand response participation means that integration of ARCs into Minnesota's markets must be carefully considered because additional demand response benefits are uncertain but implementation costs are virtually guaranteed. In requesting that utilities submit reports on tariff changes required to accommodate ARC operations, the PUC is investigating one way to facilitate ARC participation. Should the PUC proceed with any changes in current policy related to ARCs, the findings of this study support establishing mechanisms to test the effects the PUC is interested in understanding in order to better understand the benefits that ARCs may bring to Minnesota customers and the costs associated with enabling their participation.

Section 1: Study Objectives

Respond to regulatory issues

Minnesota's investor-owned electric utilities (Xcel Energy, Minnesota Power, Otter Tail Power, and Interstate Power and Light) commissioned this report to answer questions posed by the Minnesota Public Utilities Commission ("Commission" or "PUC") in its May 18, 2010 Decision in Docket No. E-999/CI-09-1449.[1] Order Point 3 of that Decision states,

> 3. On or before September 1, 2011, Xcel Energy, Minnesota Power, Interstate Light and Power, and Otter Tail Power shall file two reports:
> a. a report on ARC operations in the wholesale markets operated by MISO and in the wholesale markets operated by other independent system operators and regional transmission organizations, focusing specifically on the impact of ARC operations on prices, reliability, nonparticipating customers, utility operations, and utility-operated demand response programs; and
> b. a report on the tariff and program changes that each utility believes would be necessary to accommodate ARC operations in Minnesota.[2]

This report focuses on 3.a. Utilities will provide responses to 3.b. in separate documents.

Determine impact of ARCs by addressing additional questions

Although the Commission asks straightforward questions, the answers to these questions are complicated. The complexities stem from the nature and diversity of the RTOs in which ARCs operate and the difficulty of distinguishing between ARCs and other demand response participants in wholesale markets and the interaction of retail demand response with the wholesale markets. As with many policy questions, these complexities make it difficult to provide definitive answers to the Commission's questions without direct access to detailed and likely confidential ISO/RTO data. Thus, in an attempt to provide a meaningful response to the Commission's direction, the authors have re-phrased and expanded upon the PUC's questions.

These questions follow:

- What impacts do ARC operations have on prices?
  - Does demand response generally have an impact on prices?
  - Can one draw distinctions between ARC and non-ARC participation in wholesale markets in order to explain potential differential impacts on prices?
- What impacts do ARC operations have on reliability?

[1] "In the Matter of an Investigation of Whether the Commission Should Take Action on Demand Response Bid Directly into MISO Markets by Aggregators of Retail Customers Under FERC Orders 719 and 719-A," Minnesota Public Utilities Commission (Docket No. E-999/CI-09-1449), May 10, 2010.

[2] "In the Matter of an Investigation of Whether the Commission Should Take Action on Demand Response Bid Directly into MISO Markets by Aggregators of Retail Customers Under FERC Orders 719 and 719-A," p. 7.

    - Does demand response generally have an impact on reliability?
    - Can one draw distinctions between ARC and non-ARC participation in wholesale markets in order to explain potential differential impacts on reliability?
- What impacts do ARC operations have on nonparticipating customers?
    - Would nonparticipating customers be impacted differently from ARC vs. non-ARC demand response programs?
    - Is it possible to determine whether the benefits of ARCs exceed their costs?
- What impacts do ARC operations have on utility operations?
    - What is the definition of utility operations?
    - Is this a relevant question if "utilities" in the RTOs in which ARCs operate are basically distribution companies [because the retail markets have been deregulated]?
    - Does a deregulated retail market facilitate ARC participation and reduce the potential impacts on utility operations?
- What impacts do ARC operations have on utility-administered demand response programs?
    - Do utilities in RTOs in which ARCs are active have significant utility-administered demand response programs?
    - Can utility and ARC-administered demand response programs complement one another?
    - Do utility and ARC-administered demand response programs compete?

Refining and re-phrasing the questions helps clarify the issues the PUC's questions raise. The following sections address these issues.

The report is organized as follows. The first section provides an overview of the study's objectives. The second section explains the approach the authors have taken to address the questions. The third section explains the study's finds and the fourth section provides recommended next steps. The final section concludes the report.

Section 2: Study Approach

Summary of secondary research, not primary

As a first step, this report must determine how to assess the impacts of ARC operations on prices, reliability, nonparticipating customers, utility operations, and utility-operated demand response programs. Ideally, the study would address the first three elements (prices, reliability and nonparticipating customers) using primary research to produce specific quantitative estimates. For example, "ARC operations in the PJM Interconnection have resulted in a reduction/an increase in prices of 5 percent over the 2009-2010 period."

Unfortunately, such a quantitative study would require significant amounts of time, resources, and access to detailed RTO/ISO data. Even with such access, specific quantitative results are unlikely since RTOs do not segregate ARCs from non-ARCs for reporting purposes. In addition, because of the nature of prices and reliability, demand response impacts, and the integrated nature of ARC participation in wholesale markets, such a study would likely not yield definitive results.

Given these constraints, the authors conducted a search for existing (primary data) reports but found little that would facilitate direct answers to the PUC's questions. This search included reviews of existing reports about the effects of demand response generally on prices, reliability and other relevant topics, inquiries to organizations familiar with these topics, discussions with representatives of the targeted Independent System Operators (ISOs) – the Midwest ISO (MISO), the PJM Interconnection (PJM), ISO New England (ISO-NE), and the New York ISO (NYISO), and conversations with ARCs and utilities. Although this search elicited some useful primary data about demand response, this data did not support complete answers to the PUC's questions.

This review led the authors to conclude that the best approach to answering the questions was to use primary data (conversations with knowledgeable sources) and some secondary data to address the effects of ARCs on utility operations and utility-administered demand response programs and to use secondary data (RTO reports, consultant and academic reports, regulatory decisions) to attempt to address the effects ARCs have on prices, reliability and non-participants.

Despite the aforementioned limitations, there is ample information about the impacts <u>demand response</u> is having on prices and reliability. The impacts on non-participants are less clear and not as readily available.

Generally limited to MISO, PJM, ISO-NE, and NYISO

The study focused on four Regional Transmission Operators (RTOs): the Midwest Independent Transmission System Operator, PJM Interconnection, ISO New England, and the New York Independent System Operator. It should be noted that information from MISO is very limited because, according to MISO representatives, ARCs are not yet participating in MISO markets.

Section 3: Study Findings

Background

Aggregators of retail customers (ARCs[3]) have been active participants in wholesale markets operated by PJM, ISO-NE, NYISO, and ERCOT for several years. In addition, ARCs have also signed numerous contracts with utilities and other load serving entities (LSEs).[4] ARCs are not currently participants in MISO markets.[5]

As of this writing, the Federal Energy Regulatory Commission (FERC) has not approved MISO's revisions to its Open Access Transmission, Energy and Operating Reserve Markets Tariff regarding the participation of ARCs in Midwest ISO's markets and, therefore, no ARCs are currently participating in MISO markets.[6] However, once FERC acts on the tariff change filing, ARCs will still be required to certify that the "law, regulations, order(s)" of the Relevant Electric Retail Regulatory Authority (RERRA) do not preclude such participation.[7]

FERC Order 719 includes an "opt out" provision for RERRAs. "An independent system operator or regional transmission organization must not accept bids from an aggregator of retail customers that aggregates the demand response of the customers of utilities that distributed more than 4 million megawatt-hours in the previous fiscal year, where the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into organized markets by an aggregator of retail customers, or the customers of utilities that distributed 4 million megawatt-hours or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into organized markets by an aggregator of retail customers." [8]

Nearly all of the states within MISO's footprint (Indiana, Iowa, Michigan, Minnesota, Missouri, North Dakota, South Dakota, Wisconsin) have issued regulatory decisions opting out of the FERC's requirement to allow ARC participation (see Appendix B for further information). The

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[3] This report will use the Federal Energy Regulatory Commission term, ARCs, to describe aggregators of retail customers in its Order 719 - "Final Rule: Wholesale Competition in Regions with Organized Electric Markets," Federal Energy Regulatory Commission (Docket Nos. RM07-19-000 and AD07-7-000), October 17, 2008, p. 3.

[4] This report distinguishes between "utilities" which are defined as vertically-integrated utilities and "load serving entities" a term which includes utilities, but also includes retail electric providers in states that have implemented deregulation (restructuring).

[5] MISO formalized demand response participation in its markets with launch of the "Day 2" market in April 2005. "Demand Response in the Midwest ISO: An Evaluation of Wholesale Market Design," Sam Newell, Attila Hajos (The Brattle Group), Prepared fore the Midwest Independent System Operator, January 29, 2010, p. 8.

[6] "Midwest Independent Transmission System Operator, Inc. Filing re Aggregators of Retail Customers Docket No. ER09-1049-002," Midwest Independent Transmission System Operator, Federal Energy Regulatory Commission Docket No. ER09-1049-002, October 2, 2009.

[7] "Frequently Asked Questions: Aggregator of Retail Customers (ARC) Registration," Midwest Independent System Operator, p. 2.

[8] 18 Code of Federal Regulations §35.28(g)(1)(iii).

only MISO states that currently allow aggregators are Illinois, Ohio, and Indiana. All three of these states are served by both PJM and MISO, and Illinois and Ohio have deregulated their retail electricity markets. Indiana is the lone state within the MISO's footprint that allows ARC participation and has not deregulated its retail electricity markets.[9]

The distinction between states that have deregulated their retail electricity markets and those that have not is a very important one. For the most part, RTOs with very active ARC participation include states that have deregulated their retail electricity markets. This makes sense because the utilities in deregulated states are legally required to facilitate provision of retail electric service by competitive retail electric suppliers. As such, retail customers can also choose an ARC to provide curtailment services with fewer concerns about reliability, retail revenues/rates, and logistical issues because many of these issues have already been dealt with during the deregulation process. In addition, the RTOs have historically been actively involved in the deregulation process by ensuring that wholesale markets are designed to ensure efficient allocation of generation and curtailment resources and reliable service.

This study, therefore, focuses primarily on PJM, ISO-NE and NYISO. Although there is little opportunity to compare with MISO markets, it has become something of an accepted fact that increased levels of demand response within competitive wholesale markets have the potential to reduce overall prices and improve reliability.[10] This "fact" forms the foundation for the Federal Energy Regulatory Commission's recent Orders 719 and 745, which (among other objectives) aim to facilitate greater levels of demand response in organized wholesale electricity markets. To facilitate more demand response, Order 719 says that RTOs and ISOs have a duty to remove unreasonable barriers to treating demand response resources comparably with other resources.[11]

Prices

- Does demand response generally have an impact on prices?
- Can one draw distinctions between ARC and non-ARC participation in wholesale markets in order to explain potential differential impacts on prices?

What do we mean by prices?

This study focuses on wholesale electricity prices as opposed to retail prices. Wholesale prices refer to the price of electricity set by transactions in wholesale electricity markets that, for much of the United States, are organized by Regional Transmission Operators. "The balance of supply and demand and the cost to produce power essentially determine wholesale electricity prices."[12] There are three primary markets at the wholesale level: energy, capacity and ancillary services. Not all RTOs have formal markets for all three.

Most studies focus on the impact demand response has on energy prices. Wholesale energy markets include the day-ahead energy market in which resources and loads are bid and settled

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[9] Note that Michigan has also deregulated its retail electricity market but prohibits ARCs (with the exception of certain PJM legacy contracts).

[10] These reports are listed in Appendix A.

[11] "Final Rule: Wholesale Competition in Regions with Organized Electric Markets," p. 150.

[12] "Wholesale Electricity Markets," ISO New England, http://www.iso-ne.com/img/wem.pdf, August 7, 2011

the day ahead of the real-time market. As compared to real-time energy, this market provides greater certainty for suppliers and consumers of electricity and ensures that fewer transactions occur in the more volatile real-time market. Real-time energy is the balancing settlement for the quantity deviations from each participant's day-ahead energy market obligations whereas the real-time energy market is a spot market in which current prices are calculated at intervals (usually five minute) based on actual grid operating conditions.

Demand response can also affect prices for capacity and ancillary services, but these do not get as much attention. As described in a report about PJM,

> The effects of demand response on energy prices are often discussed, but the potential effects on capacity prices are rarely mentioned. Demand response could reduce capacity prices by reducing peak loads and therefore reducing the demand for capacity, as determined by PJM's resource adequacy requirements. If the demand for capacity is reduced, then the capacity market could clear at a lower price, particularly if the demand reduction shifts the market balance from a capacity scarcity to a capacity surplus.[13]

In the past, demand response, particularly utility interruptible programs, has been frequently evaluated based on its ability to provide lower cost capacity. Utility integrated resources plans have long incorporated interruptible capacity because it tends to be lower cost than peaking generating units.[14] But the more recent focus has shifted to demand response's effects on energy prices because demand response is viewed as a potential proxy for dynamic pricing. Many economists and regulators consider full implementation of dynamic retail electricity pricing (also referred to as "price responsive demand" or PRD) to be the ultimate goal, with demand response programs as a bridge to this goal.[15]

Demand response's effects on the cost for ancillary services is not well known, largely because demand response has only recently begun to provide ancillary services. In addition, capacity and ancillary services are considered reliability products. They will be discussed further in the section on reliability.

What impacts do ARC operations have on prices?

As discussed, there is insufficient quantitative data to directly determine the impact of ARCs on prices. That said, we can answer the sub-question, "Does demand response generally have an

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[13] "Quantifying Demand Response Benefits In PJM," Prepared by The Brattle Group for the PJM Interconnection and the Mid-Atlantic Distributed Resources Initiative (MADRI), January 29, 2007, p. 27.

[14] IRP presents price effects in terms of "avoided costs". A recent study for the Avoided-Energy-Supply-Component (AESC) Study Group examined such costs for New England and incorporated the latest information from ISO-NE's energy and capacity markets. "Avoided Energy Supply Costs in New England: 2011 Report," Prepared for the Avoided-Energy-Supply-Component Study Group by Synapse Energy Economics, July 21, 2011.

[15] *See* "Price Responsive Demand," *PJM Staff Whitepaper*, March 3, 2011; "Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005," U.S. Department of Energy, February 2006; "Fostering Economic Demand Response in the Midwest ISO," Prepared for the Midwest Independent Transmission System Operator by The Brattle Group, December 30, 2008.

impact on prices?" There is general consensus that demand response successfully reduces wholesale energy prices, at least in the short run, and it also can help reduce prices for (or "the cost of," if not market provided) capacity and ancillary services. In these cases, demand side resources have proven to be obtainable at lower prices than marginal generation sources. As stated in a recent article by the current Chairman of the Federal Energy Regulatory Commission,

> FERC has recognized a number of benefits associated with participation by demand response in the organized markets. Addressing one important benefit, FERC has stated that demand response helps to reduce prices in competitive wholesale markets in at least three ways. First, when demand response is bid directly into a wholesale market, the lower demand means a lower wholesale price. Second, demand response tends to flatten an area's load profile, thereby reducing the need to use more costly resources during periods of high demand and lowering the overall average cost to produce energy. Third, demand response reduces generator market power. The more demand response that is available during peak periods, the more downward pressure it places on generator bidding strategies by increasing the risk to a power supplier that it will not be dispatched if it submits too high a bid (FERC 2008a, P 29-31).
>
> The benefits stemming from demand response, however, go beyond reductions in wholesale prices. For example, FERC has stated that demand response enhances reliability and supports the use of renewable energy resources (FERC 2008a, P 27).[16]

As evidenced by the rise of demand side management (DSM) and least cost resource planning (integrated resource planning or IRP) in the 1970s, this conclusion is not a new realization. The National Energy Conservation Policy Act of 1978 "was an acknowledgment that saving energy could be cheaper than producing it" and many states followed suit by requiring utilities to implement DSM programs and IRPs.[17]

What is new is the rise of a new class of market participants called aggregators of retail customers and integration of demand response into wholesale markets. In fact, ARCs have existed since the inception of RTO demand response programs in the late 1990s; however, their role in wholesale markets has increased markedly over the last several years, particularly as Northeastern RTOs have created opportunities for greater participation. FERC has adopted the view that:

> Aggregating small retail customers into larger pools of resources expands the amount of resources available to the market, increases competition, helps reduce prices to consumers and enhances reliability…We also agree with commenters

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[16] "Creating Regulatory Structures for Robust Demand Response Participation in Organized Wholesale Electric Markets," Hon. Jon Wellinghoff, David L. Morenoff, James Pederson, Mary Elizabeth Tighe, Federal Energy Regulatory Commission, 2008 ACEEE Summer Study, p. 2.

[17] "The Past, Present, and Future of U.S. Utility Demand-Side Management Programs," Joseph Eto, Environmental Energy Technologies Division Ernest Orlando Lawrence Berkeley National Laboratory, December 1996, p. 5.

> that (aggregation) could encourage development of demand response programs and thereby provide retail customers more opportunities available through larger markets.[18]

Two RTOs, ISO-NE (since 2003) and NYISO (since 2001) with large amounts of ARC participation are required to submit reports to the Federal Energy Regulatory Commission documenting the effects demand response has had on prices. The two RTOs estimated demand response impacts on energy prices using their day-ahead demand response programs. ISO-NE ran simulations using participation in its Day-Ahead Load Response Program (DALRP) to estimate what real-time prices would have been had been with and without interruptions. NYISO analyzed actual schedules, loads and prices using participation in its Day-Ahead Demand Response Program (DADRP). See Appendix C for a detailed description of RTO demand response activities.

ISO-NE's DALRP is an optional program that allows a participant in the RTPR (Real-Time Price Response) program to offer interruptions concurrent with the Day-Ahead Energy Market. Participants in the DALRP are paid the Day-Ahead LMP for the cleared interruptions, and Real-Time deviations are charged or credited at the Real-Time LMP.[19]

From the December 2010 ISO-NE report,

> During the first two months of the Reporting Period, the Load Response Program reduced real-time LMPs by approximately $0.61/MWh across the entire wholesale market in New England. The largest average decrease, $0.87/MWh, was seen in Connecticut. During the latter four months of the Reporting Period, due in part to a tenfold increase in interrupted MWh per month, the program reduced real-time LMPs by approximately $1.72/MWh across the entire market, with the largest average decrease of approximately $2.15/MWh seen in Maine ... (These reductions in prices) decreased energy costs charged to load in the New England region by about $8.8 million during the Reporting Period.[20]

The most recent NYISO report provides a summary of the DADRP's estimated impacts since 2001,[21]

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[18] "Order 719," pp. 83-84.

[19] "Semi-Annual Status Report on Load Response Programs of ISO New England Inc., Docket No. ER03-345-," ISO New England, December 30, 2010 p. 3.

[20] The reporting period was April-September 2010. "Semi-Annual Status Report on Load Response Programs of ISO New England Inc., Docket No. ER03-345-," p. 12. Although 2009 was not as active a year for demand response as 2008, the results from 2008 were not appreciably different.. Estimates in price reductions did not account for potential increases in load that occurred in non-event periods due to load shifts from event to non-event periods.

[21] "Annual Report in Docket Nos. ER01-3001-000," New York Independent System Operator, Submitted to the Federal Energy Regulatory Commission (Docket No. ER01-3001-000), January 18, 2011, p. 27.

Figure 1 – NYISO Day Ahead Demand Response Program Summer Price Reductions

Table 10: DADRP Average Price Reductions (Summer Season)

	Scheduled DADRP MWh	Program Payments		Average Price Reduction ($)		Average Hourly Schedule (MWh)
2001	2,694	$	217,487	$	0.58	5.07
2002	1,468	$	110,216	$	0.30	6.99
2003	1,752	$	121,144	$	0.12	2.79
2004	675	$	40,651	$	0.07	3.04
2005	829	$	77,885	$	0.10	4.02
2006	295	$	29,821	$	0.05	1.53
2007	765	$	64,737	$	0.04	1.67
2008	3,177	$	348,509	$	2.05	1.71
2009	28	$	2,605	$	-	1.00
2010	20	$	-	$	-	5.00

> The DADRP program provides demand resources with an opportunity to offer their load curtailment capability into the Day-Ahead energy market as energy supply resources. Resources submit offers by 5:00 a.m., specifying the hours and amount of load curtailment they are offering for the next day, and the price at which they are willing to curtail … the offer floor price for DADRP has been set at $75/MWh. Offers are structured like those of generation resources, so DADRP program resources may specify minimum and maximum run times and effectively submit a block of hours on an all-or-nothing basis … Load scheduled in the DAM is obligated to curtail the next day. Failure to curtail results in the imposition of a penalty equal to the product of the MW curtailment shortfall and the greater of the corresponding Day-Ahead and Real-Time market price.[22]

NYISO sets a floor price to "prevent a DADRP Resource from submitting low bids for periods of time when its load would already be off-line for maintenance or regularly scheduled shutdowns, thus discouraging free-ridership and bidding behavior that provides no real benefit."[23] In Figure 1, Scheduled DADRP MWh is the sum of all scheduled DADRP during the analysis period while payments are the sum of the scheduled MWh in a specific hour multiplied by the day-ahead locational market price. Average price reduction represents the estimated impact that the DADRP performance had on the day-ahead locational market price.[24]

ARCs are not significant players in NYISO's DADRP, instead focusing on the reliability programs. The following graph shows the percentage of total participation for the DADRP by provider type.

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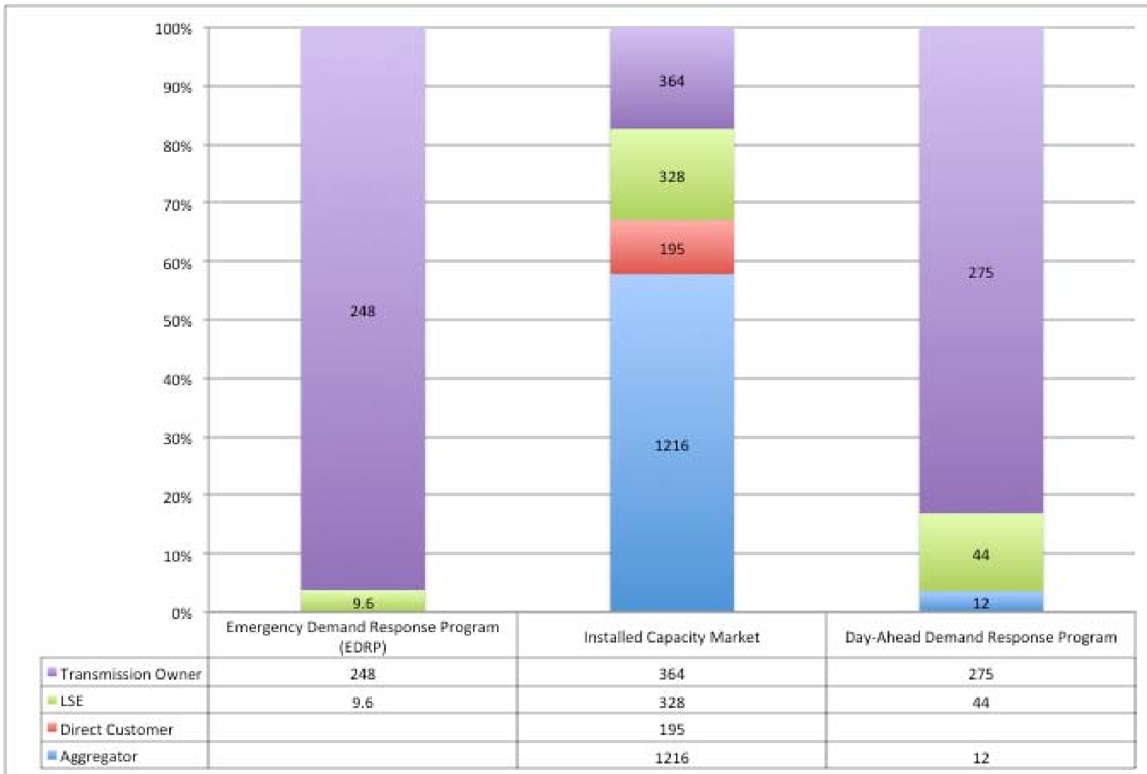
[22] "Annual Report in Docket Nos. ER01-3001-000," p. 18.

[23] "Letter Order to NYISO," Federal Energy Regulatory Commission (Docket No. ER04-1188-000), October 29, 2004, p. 1.

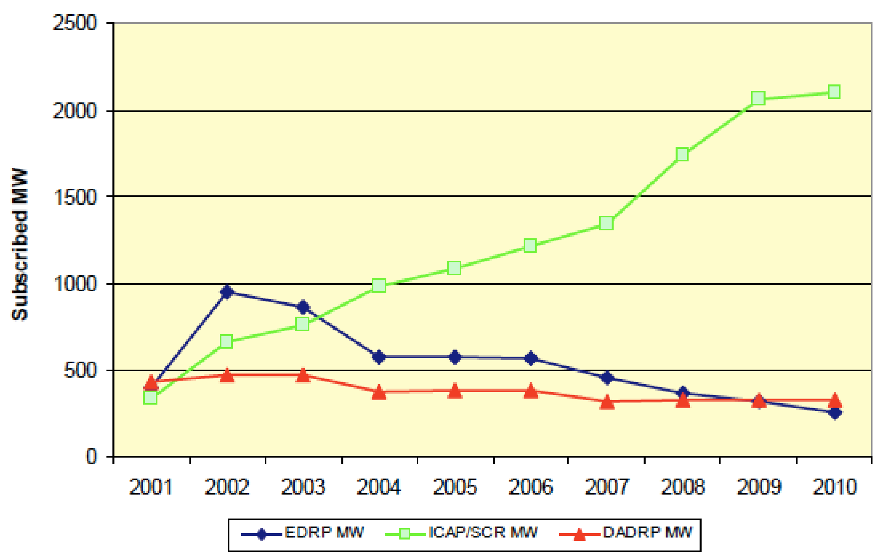
[24] "Compliance Filing in Docket Nos. ER01-3001-, ER03-647-," New York Independent System Operator, Submitted to the Federal Energy Regulatory Commission (Docket No. ER01-3001-000), January 15, 2009, p. 23.

Figure 2 - NYISO 2010 DR Program Participation by Provider Type (megawatts and % of total)[25]



Overall participation (MW) in NYISO's DADRP has remained fairly steady over the years while participation in its ICAP/SCR program has increased nearly every year (see Figure 3).

Figure 3 – NYISO Demand Response Program Enrollment 2001-2010 (MW)



[25] Annual Report in Docket Nos. ER01-3001-000," January 18, 2011, p. 9.

The scope of the instant report did not provide the opportunity to fully analyze the reasons for this shifts between programs, but according to the NYISO the shift from its Emergency Demand Response Program (EDRP) to the ICAP/SCR program is at least partly due to the monthly reservation payment associated with the ICAP/SCR program.[26]

PJM does not have any reporting requirements similar to those for ISO-NE and NYISO, but PJM commissioned a study in 2007 from the Brattle Group to quantify demand response benefits.[27] The study used "a simulation-based approach to quantify the market impact of curtailing 3 percent of load in the BGE, Delmarva, PECO, PEPCO, and PSEG zones during the top twenty 5-hour price blocks in 2005 and under a variety of alternative market condition."[28] The simulations determined that:

- Curtailing 3% of each selected zone's super-peak load, which reduces PJM's peak load by 0.9%, yields an energy market price reduction of $8-$25 per megawatt-hour, or 5-8% on average, during the 133-152 hours in which curtailment occurs in at least one zone. The range depends on market conditions.
- Assuming all loads (i.e., customers or their retail providers) are exposed to spot prices, the estimated price reductions could benefit non-curtailed loads in MADRI states by $57- $182 million per year. The potential benefits to the entire PJM system amount to $65- $203 million per year.[29]

The estimated values from the PJM study are much higher than those estimated by ISO-NE and NYISO, likely due to the megawatts of demand response used in the PJM study as compared to the actual amounts registered in ISO-NE and NYISO. The ability to curtail 3 percent of a region's super-peak load would have a demonstrably larger effect than the approximate 1 percent (author's estimate) of load actually available for day-ahead scheduling in NYISO, ISO-NE and PJM.

The study did not segregate ARCs from other market participants. PJM does not break out the different types of "curtailment service providers" that participate in its demand response programs.

In *Fostering Economic Demand Response in the Midwest ISO*, the Brattle Group reported that, "comments from FERC and the RTOs, publicly available data on CSPs, and our interviews with the three largest CSPs indicate that CSPs contribute a large fraction, if not the majority, of DR in PJM and ISO-NE, as well. This could, in fact, be due to the retail choice environments prevalent in the East, whereas, MISO has mostly a regulated rate environment."[30] This may be true but PJM representatives point out that a number of utilities (local distribution companies or LDCs)

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[26] "Annual Report in Docket Nos. ER01-3001-000," p. 14.

[27] "Quantifying Demand Response Benefits In PJM."

[28] "Quantifying Demand Response Benefits In PJM," p. 2.

[29] "Quantifying Demand Response Benefits In PJM," p. 2.

[30] "Fostering Economic Demand Response in the Midwest ISO," Prepared for the Midwest Independent Transmission System Operator by The Brattle Group, December 30, 2008, 53.

are also active participants. These LDCs include Baltimore Gas & Electric (MD), Commonwealth Edison (IL), and Public Service Electric & Gas (NJ).

Thus, given the impact of demand response on prices and the participation of ARCs in demand response activities, it is likely that ARC operations have had an impact on prices but this value is difficult to quantify. The one RTO (ISO-NE) that provides information about participants in its day-ahead market indicates that ARCs are not very active in this market.

Claims by ARCs, utilities, and others about ARC participation

In conducting research, the authors sought information from a selection of aggregators. The aggregators were also not aware of existing studies that segregated ARC participation from other market participants but pointed to studies that demonstrated the effects demand response can have on wholesale market prices. In addition, aggregators highlighted the fact that much of the new demand response participation in wholesale markets, particularly in the Northeast, is from aggregators. Considering the increasing role aggregators are playing in wholesale markets, aggregators believe that a persuasive argument can be made that, to the extent that demand response impacts (lowers) prices, that aggregators are the primary causes of these impacts because of their role in the market.

This may be true, but it is a difficult claim to confirm without true quantitative studies that segregate ARCs from other participants. By the same token, it very well may be true that non-ARC participants in wholesale markets would have the same impacts on prices. In this sense, the issue isn't so much the impact ARCs have on prices (or reliability) but rather is the active participation of ARCs a necessary feature for wholesale markets to benefit from demand response?

In Order 719, FERC comes down strongly in support of RTOs facilitating greater amounts of ARC participation in wholesale markets, and one can assume that this support is heavily aimed at RTOs that do not currently have large amounts of ARC participation (MISO, Southwest Power Pool, California Independent System Operator). For its part, MISO has commissioned a number of recent studies to examine ways MISO can improve its markets for participation by demand response and energy efficiency resources (among other changes).[31]

These studies conclude that MISO markets would benefit from more active demand side participation while acknowledging that MISO currently has a fairly large demand side resource, mainly from legacy utility interruptible programs. The Brattle Group's *Fostering Economic Demand Response in the Midwest ISO* comes down strongly in favor of increasing price-responsive demand response in the Midwest and recommends that MISO enable "participation of curtailment service providers (CSPs) in its energy markets as at least a bridge to a future in

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[31] *See* "Fostering Economic Demand Response in the Midwest ISO; "Midwest Retail Demand Response Program Survey Results," by Chuck Goldman, Ranjit Bharvirkar, Grayson Heffner, Lawrence Berkeley National Laboratory for the Midwest Demand Response Initiative (MWDRI), March 7, 2008; "Demand Response in the MISO: An Evaluation of Wholesale Market Design," Sam Newell, Attila Hajos, The Brattle Group for the MISO (MISO), January 29, 2010; "Assessment of Demand Response and Energy Efficiency Potential for MISO," Global Energy Partners, LLC, Report #1314, November 2010.

which the states enable the first-best approach to economic DR by implementing widely retail rates with dynamic pricing."[32]

The study goes on to say that, "CSPs can provide expertise, technology, and a willingness to take risk that many utilities lack. LSEs and CSPs are not necessarily in competition with each other. For example, CSPs may be able to approach more customers that LSEs find difficult to manage. Furthermore, working through LSEs may reduce the CSPs' marketing costs."[33]

The same study, though, acknowledges that Minnesota ranks highest among MISO states in terms of "likelihood of producing significant DR impacts" and does not point to Minnesota as one of the states where "CSPs can help to fill those gaps."[34] The study also suggests that increasing levels of price-based demand response in the Midwest can be accomplished in three different ways: 1) load serving entities should move retail customers to time-based pricing, 2) LSEs and possibly third parties (ARCs) should bid price responsive demand curves into wholesale markets and/or 3) demand response should be bid as a supply resource into the wholesale market.[35] In other words, ARCs can be part of the solution but so, too, can utilities.

But there is another important point that should not be lost in the discussion of demand response, prices and ARCs. *Fostering Economic Demand Response in the Midwest ISO* and similar studies emphasize the value of demand response as a proxy for dynamic pricing and consider key to this demand response programs that can directly impact day-ahead and real-time energy prices. However, demand response programs that affect day-ahead and real-time energy markets are <u>not</u> well subscribed (relative to capacity programs) and whether or not ARCs are active participants in these programs may not be as important as the fact that overall participation is not very robust.

Reliability

- Does demand response generally have an impact on reliability?
- Can one draw distinctions between ARC and non-ARC participation in wholesale markets in order to explain potential differential impacts on reliability?

What is reliability?

The North American Electric Reliability Corporation (NERC) defines the reliability of the interconnected bulk power system in terms of two basic and functional aspects:

- Adequacy — The ability of the bulk power system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

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32 "Fostering Economic Demand Response in the Midwest ISO," p. 3.

33 "Fostering Economic Demand Response in the Midwest ISO," p. 55.

34 "Fostering Economic Demand Response in the Midwest ISO," pp. 71-74.

35 "Fostering Economic Demand Response in the Midwest ISO," pp. 2-3.

- Security — The ability of the bulk power system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements from credible contingencies.[36]

NERC develops standards for reliability planning and the reliable operation of the bulk power systems. The Energy Policy Act of 2005 added Section 215 to the Federal Power Act to establish a framework for making reliability standards mandatory for all bulk power system owners, operators and users.

Demand response and reliability

Demand response can effectively help satisfy requirements for adequacy and security. According to NERC, in "addition to providing capacity for resource adequacy and planning purposes, capacity and ancillary services provided by Demand Response helps ensure resource adequacy while providing operators with additional flexibility in maintaining operating reliability. However, Demand Response is still a relatively new resource, and both NERC and stakeholders need to measure its performance in order to gauge its benefits and impacts on reliability. Better performance measures will also help develop industry confidence in Demand Response use."[37]

Although utilities have historically used demand response to help ensure the reliable operation of the grid, this responsibility has shifted to RTOs in many regions. RTOs are in the process of integrating demand response (and energy efficiency) into their activities to ensure both short-term and long-term reliability. RTOs are following the requirements of Section 1252(f) of the Energy Policy Act of 2005 which states that "deployment of such technology and devices that enable electricity customers to participate in such pricing and demand response systems shall be facilitated, and unnecessary barriers to demand response participation in energy, capacity and ancillary services markets shall be eliminated."[38]

Demand response can participate in two reliability related markets: ancillary services and capacity. Ancillary services act as an insurance policy against the unforeseen loss of a major power plant or transmission line and basically keep the electrical system in balance. Procurement of such services can be cost-base or market-based. Ancillary services include:

- **Forward and Real-Time Operating Reserves** - ensure that sufficient resources are held in "reserve" and are available to produce electricity on short notice when an outage or another problem occurs. These can be provided by demand response.

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[36] http://www.nerc.com/page.php?cid=1|15|123. The Bulk Power System refers to the "part of the overall electricity system that includes the generation of electricity and the transmission of electricity over high-voltage transmission lines to distribution companies. This includes power generation facilities, transmission lines, interconnections between neighboring transmission systems, and associated equipment. It does not include the local distribution of the electricity to homes and businesses."

[37] http://www.nerc.com/page.php?cid=4%7C357. Accessed on August 8, 2011.

[38] "Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005," U.S. Department of Energy, February 2006.

- **Regulation -** allows RTOs to instruct specific power plants to increase or decrease output moment-by-moment to balance system frequency, which must always be kept at a constant rate. Demand response can provide regulation services.
- **Voltage Support -** allows the system operators to maintain transmission voltages within acceptable limits. Demand response is not generally used for voltage support.
- **Black-Start Capability -** is provided by specific power plants at strategic locations and involves restoring generation to restart the transmission system following a system wide blackout. Demand response is not generally used for black-start capability.[39]

"Capacity markets compensate supply resources and demand resources either for the electricity they are capable of producing if needed—or in the case of demand resources, for the electricity they avoid using—to ensure that enough electricity capacity exists to meet regional reliability requirements."[40]

Ancillary services and capacity are not always procured through markets but rather may also be obtained through bi-lateral contracts between entities responsible for maintaining reliability (RTOs, utilities) and providers of such services. RTOs are still in the process of implementing markets for all types of ancillary services and some RTOs (such as the MISO) don't have capacity markets.[41] In RTOs that do not have capacity markets, RTOs rely upon load serving entities to ensure sufficient levels of capacity to meet demands.

Demand response and energy efficiency are playing increasingly important roles in providing ancillary services and capacity due to each resource's flexibility, cost, environmental attributes and speed of implementation. In Order 719, FERC required RTOs to accept bids from demand response providers for ancillary services on a comparable basis with other resources as long as the demand response resources could meet technical specifications.[42] RTOs with formal capacity markets, including ISO-NE, PJM and NYISO, now allow participation by demand response resources (and in ISO-NE and PJM's cases, energy efficiency). This is to say that demand response services play active roles in delivering both short-term and long-term reliability. The graphic below depicts these roles relative to other resources.

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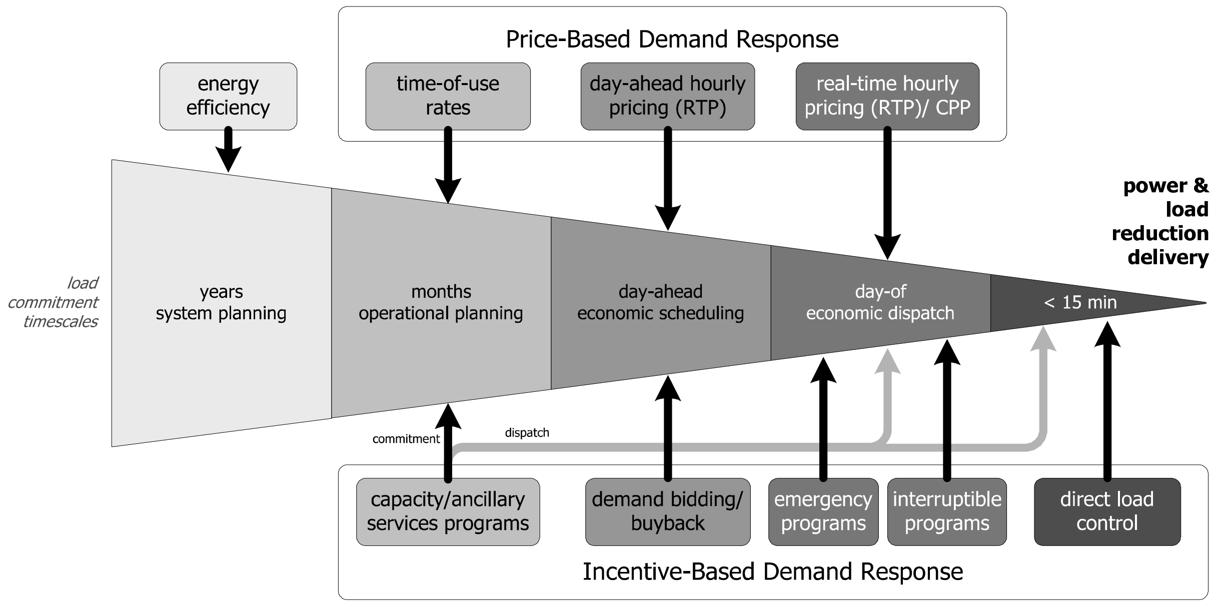
[39] "Wholesale Electricity Markets," ISO New England, http://www.iso-ne.com/img/wem.pdf, accessed on August 8, 2011.

[40] Ibid.

[41] MISO recently filed with FERC its "enhanced resource adequacy construct" (Midwest Independent Transmission System Operator, Inc. Filing to Enhance RAR By Incorporating Locational Capacity Market Mechanisms; FERC Docket Nos. ER08-394-004; ER08-394-005; ER08-394-021; ER08-394-022; ER08-394-028; ER08-394-029; and ER11- ___ -000, July 20, 2011). The construct proposes to establish a short-term capacity market (1 year) but provides opportunities for LSEs in non-retail choice states to "opt out" of the auction.

[42] "Final Rule: Wholesale Competition in Regions with Organized Electric Markets, Docket Nos. RM07-19-000 and AD07-7-000," Federal Energy Regulatory Commission, p. 27.

Figure 4 - Role of Demand Response Electric System Planning and Operation[43]



What impact do ARCs have on reliability?

Demand response is increasingly relied upon by RTOs to provide ancillary services and capacity and, therefore, demand response is playing a very important role in ensuring the reliability of the electricity system. In an effort to systematically quantify the effects demand response has on reliability, NERC created the Demand Response Availability Data System (DADS). According to NERC,

> Demand response is one of many resources needed to satisfy the increasing demand for electricity in North America. In addition to providing capacity for resource adequacy and planning purposes, capacity and ancillary services provided by Demand Response helps ensure resource adequacy while providing operators with additional flexibility in maintaining operating reliability. However, Demand Response is still a relatively new resource, and both NERC and stakeholders need to measure its performance in order to gauge its benefits and impacts on reliability…The goal of the DADS is to collect Demand Response enrollment and event information to measure its actual performance including its contribution to improved reliability. Ultimately, this analysis can provide industry with a basis for projecting contributions of dispatchable and non-dispatchable (e.g., price-driven) Demand Response supporting forecast adequacy and operational reliability. [44]

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[43] "Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005," U.S. Department of Energy, p. 15.

[44] http://www.nerc.com/page.php?cid=4%7C357, accessed on August 25, 2011.

NERC is in the process of implementing the mandatory "Phase II" of DADS and expects to have semi-annual reports that will include statistics and metrics to assess demand response's impacts on reliability and resource adequacy. Submitted data will be treated as confidential information.

But, again, there is an issue with distinguishing ARC contribution to reliability relative to other players in the market. Although one can make a persuasive argument that ARCs, because of their very active participation in ISO-NE, PJM and NYISO ancillary services and capacity markets, contribute significantly to reliability, it is not easy to distinguish the contribution that ARCs make vis-à-vis other players.

Starting with the 2007/8 delivery year, demand side resources can participate in PJM's Reliability Pricing Model (RPM).[45] RPM is PJM's capacity-market model. Designed to create long-term price signals to attract needed investments in reliability, PJM requires that participants make capacity commitments three years ahead. For the 2012/13 planning year, demand response is expected to provide over 5% of the total cleared capacity resources, a value that increases to 9.4 percent for the 2014/2015 planning year.[46] Although PJM does not break out the portion of its demand response resources that are provided by ARCs vs. other entities, it appears that ARCs are very active participants in this market, too.

ARCs are the majority of participants in NYISO's reliability programs. According to its report to FERC, of the 56 Curtailment Service Providers (CSPs) and Responsible Interface Parties[47] participating in the ISO's Emergency Demand Response Program (EDRP) and ICAP/SCR (Installed Capacity/Special Case Resource) program, 7 were transmission owners, 6 were load-serving entities not affiliated with a Transmission Owners, 31 were aggregators that were not load serving entities or transmission owners and 12 were direct resources (typically large end-use customers).[48]

The demand response resources in NYISO reliability programs represent 7.0% of the 2010 Summer Capability Period peak demand of 33,452 MW, an increase of 0.7% from 2009. As shown in Figure 2, in 2010 aggregators constituted a majority (~57%) of MW registered in the ICAP but a much small percentage (~2%) in the Emergency Demand Response Program.

MISO currently meets its capacity requirements by obligating LSEs to have sufficient capacity to meet demands. Demand response resources can be used by LSEs to meet their Module E (reliability section of MISO tariff) requirements. These capacity resources are fairly substantial with approximately 10,000 MW registered as of April 2011.[49] Since there are no participating ARCs, these resources are provided entirely by utilities or end-use customers. ARC participation

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[45] Demand side resource participation actually started with the 2005/6 delivery year but the RPM was implemented for the 2007/8 delivery year.

[46] "RPM Offers by Commitment and Fuel Type," http://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx, PJM, May 25, 2011. Accessed on August 8, 2011.

[47] Responsible Interface Parties are a subset of NYISO participants within the Installed Capacity Market who can receive energy and capacity payments.

[48] "Annual Report in Docket Nos. ER01-3001-000," p. 6.

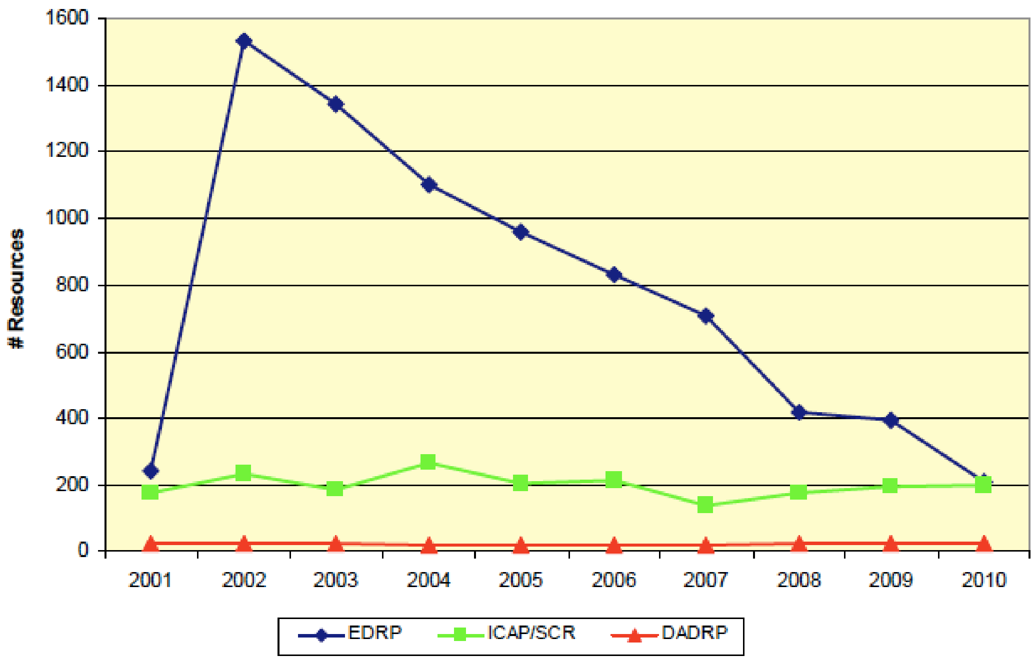
[49] "Demand Participation Update," Demand Response Working Group, Midwest ISO, April 4, 2011, p. 2.

may change these values, although it is not obvious whether the amount of participating load would increase or decrease. Due to differences with respect to retail regulation, the Northeastern RTOs are not necessarily analogous to the Midwest ISO.

Evolving ARC preferences as they relate to reliability

ARCs are clearly very active participants in capacity markets in the Northeastern RTOs. In fact, ARCs appear to be focusing heavily on capacity markets (as opposed to day-ahead and real-time energy markets). In the New York ISO, as of 2010, only three resources representing thirty locations submitted load reduction offers in the Day-Ahead Demand Response Program. In addition, "Offer activity decreased by 70% over the previous 12-month period and 87% fewer hours were scheduled (134) than in the previous period (1,067)."[50] At the end of August 2010, the NYISO's reliability programs had a total of 4,386 end-use locations enrolled, providing a total of 2,362.1 MW of demand response capability, a less than 1% decrease over the 2009 MW enrollment level.[51] (see table below)

Figure 5 - NYISO Demand Response Program Enrollment History 2001-2010[52]



This appears to have happened because ARCs find capacity market opportunities attractive due to guaranteed payments and likely limited numbers of interruptions. In addition, payments from capacity markets help compensate ARCs for investments they may have made in marketing, systems, etc. to sign-up and activate customer demand response. In contrast, utilities that run demand response programs can usually recover acquisition and systems costs through rates.[53]

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[50] "Annual Report in Docket Nos. ER01-3001-000," p. 7.

[51] "Annual Report in Docket Nos. ER01-3001-000," p. 7.

[52] "Annual Report in Docket Nos. ER01-3001-000," p. 15.

[53] Between rate cases, however, a utility as well may incur costs that are not recoverable and so may have similar incentives as ARCs.

Nonparticipating customers

- Would nonparticipating customers be impacted differently from ARC vs. non-ARC demand response programs?
- Is it possible to determine whether the benefits of ARCs exceed their costs?

Why are nonparticipating customers important?

The term "nonparticipating customers" refers to the customers within a particular area (usually a utility service territory but could also pertain to an area served by an RTO running a demand response program) that do not participate in the relevant demand response program. These customers are of interest because a basic principle of the use of demand response is that its benefits to the grid or market as a whole are greater than the total cost of securing demand response load reduction. Thus, if demand response program costs (including payments to participating customers) associated with load reductions exceed the overall financial benefits to the particular area, the nonparticipating customers could end up subsidizing participating customers because these costs need to be recovered from all customers, including nonparticipating customers. In addition, if reduction in energy use limits the load serving entity's ability to recover its fixed costs (without lowering these costs), the utility must raise rates for all customers to recover the costs.

DR and nonparticipating customers

The authors found no available quantitative data regarding the effects of ARCs on nonparticipating customers; however, to the extent that ARCs receive the same compensation as any other demand response participant or ARC compensation is designed to not increase overall costs, this issue is best addressed by prudent demand response design and implementation. FERC's opinion on the matter is clear and RTOs and utilities are using FERC's direction as a basis for demand response design.

In its Order 745, FERC attempted to resolve this issue, at least as it pertains to wholesale transactions. As the Commission states,

> "[D]ispatching demand response resources may result in an ***increased cost per unit to load associated with the decreased amount of load paying the bill,*** depending on the change in LMP relative to the size of the energy market. ... [T]his is the billing unit effect of dispatching demand response resources. ...[***W]hen reductions in LMP from implementing demand response results in a reduction in the total amount consumers pay for resources that is greater than the money spent acquiring those demand response resources at LMP***, such a payment is a cost-effective purchase from the customers' standpoint. In comparison, when wholesale energy market customers pay a reduced price attributable to demand response that does not reduce total costs to customers more than the costs of paying LMP to the demand response dispatched, customers suffer a net loss." [54] (***emphasis*** added)

[54] "Demand Response Compensation in Organized Wholesale Energy Markets," (Docket No. 17-000, Order No. 745), Federal Energy Regulatory Commission, p. 41.

This order resulted in the so-called "net benefits" test. Order 745 directs "each RTO and ISO to develop a mechanism as an approximation to determine a price level at which the dispatch of demand response resources will be cost-effective."[55] The net benefits test and payment of LMP for demand response is not without controversy, though.

The Organization of MISO States (OMS) in its Request for Rehearing of Order 745 contends that FERC's determination is "not just and reasonable because it will result in excessive compensation for certain demand response resources" and that the net benefits test "will preclude the deployment of demand response resources at certain times when it would otherwise be efficient to do so."[56] OMS also says that, by pushing the handling of the retail rate component of demand response compensation back to the states, FERC could be imposing "complex and costly changes to billing and metering systems" to facilitate "charging the retail rate to participating customers for load reductions."[57]

In the MISO states that are still under traditional ratemaking schemes and have vertically integrated utilities, only one has thus far opted to allow aggregator participation. In this state, Indiana, the Indiana Utility Regulatory Commission authorized aggregator participation in PJM and MISO wholesale demand response programs (the state includes utilities in both RTOs) through IURC-approved utility tariffs. The utilities have subsequently issued and the IURC has approved these tariffs.

The approved tariffs for Duke Energy Indiana, Inc. and Northern Indiana Public Service Company (NIPSCO) provide opportunities for ARCs to participate in PJM and MISO demand response opportunities. The tariffs compensate ARCs with whatever compensation the utility receives through the demand response activity and then reduce this amount by the Marginal Foregone Retail Rate (MFRR) along with a 5 percent administrative fee. The Marginal Foregone Retail Rate is defined as "the full marginal retail rate inclusive of trackers excluding any demand component effects."[58]

Presumably, this rate structure will help ensure that non-participating retail customers will be held harmless by customer participation in wholesale markets through ARCs. It remains to be seen whether ARCs will actively participate in these programs or what types of implications ARC participation may have for other Indiana utility demand response programs. It should be noted that Indiana only recently revived efforts to implement utility energy efficiency and currently has modest levels of utility demand response activity.[59]

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[55] "Demand Response Compensation in Organized Wholesale Energy Markets," p. 4.

[56] **"**Request for Rehearing of the Organization of MISO States," by Organization of MISO States, Federal Energy Regulatory Commission (Docket No. RM10-17-000), April 14, 2011, p. 2.

[57] "Demand Response Compensation in Organized Wholesale Energy Markets," p. 5.

[58] "Standard Energy Contract Rider No. 22: Duke Energy Market Based Demand Response (MBDR) Rider Applicable to HLF and LLF Rate Groups," Indiana Utility Regulatory Commission (IURC) Cause No. 43566, Approved March 2, 2011.

[59] As of 2010, Indiana had 1,891 MW of demand response potential peak reduction as compared to Minnesota's 4,410 MW. "Assessment of Demand Response & Advanced Metering: Staff Report," Federal Energy Regulatory Commission, February 2011, p. 38. Customer demand in Indiana is close to double Minnesota demand.

Conclusions about DR and nonparticipating customers

Demand response can have a positive effect on nonparticipating customers as well as participating customers if compensation parameters are correctly established. FERC Order 745 attempted to craft a compensation scheme so that nonparticipants would not be harmed, at least at the wholesale level, but as discussed herein, it is clear that this matter is not fully resolved. Therefore, this issue may still be left to retail regulators to sort out.

Inferences about ARCs based on DR data

It is difficult to make inferences about ARC impacts on non-participating customers based on general demand response data; however, ARC participation in wholesale markets highlights concerns about effects on nonparticipants because FERC's Order 745 requires that RTOs pay demand-response providers the locational marginal price (LMP), if the DR resource can (a) balance supply and demand and (b) satisfy FERC's cost-effectiveness test. ARCs (and large customer groups) were the primary groups advocating before FERC for payment of LMP. Others contended that payment of LMP without compensating LSEs for reduction in retail payments creates a subsidy to participants/ARCs that is economically inefficient.[60]

Regardless of Order 745, potential negative effects on nonparticipants should be remedied in a regulated retail environment as well as wholesale markets. In practice, such issues are openly discussed and debated either as part of a utility's rate case or upon proposal of new or revision to existing utility tariffs.

For markets without active wholesale demand response, protection of nonparticipants falls to retail rate design. Very few states have established arrangements whereby ARCs can participate alongside retail regulated utilities and their established retail rates to ensure that nonparticipating retail customers are not harmed (Indiana appears to provide an example of one state).

Utilities typically set retail rates based on the estimated value of the customer's reduced demand to the utility (all customers). Presumably this value is a "net benefit" to all customers, including nonparticipants. Thus, nonparticipants are protected if ARCs receive this retail rate or a rate that does not increase the overall cost of the demand response program.

Utility Operations / Utility-Operated Demand Response Programs

- What is the definition of utility operations?
- Is this a relevant question if "utilities" in the RTOs in which ARCs operate are basically distribution companies [because the retail markets have been deregulated]?
- Does a deregulated retail market facilitate ARC participation and reduce the potential impacts on utility operations?
- Do utilities in RTOs in which ARCs are active have significant utility-administered demand response programs?
- Can utility and ARC-administered demand response programs complement one another?
- Do utility and ARC-administered demand response programs compete?

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[60] *See* "Moeller, Commissioner, dissenting" in "Demand Response Compensation in Organized Wholesale Markets," Federal Energy Regulatory Commission (Docket No. RM10-17-000), March 15, 2011, p. 4.

This section combines discussion of ARC effects on utility operations and utility-administered demand response programs because these are inter-related issues as applied to utilities in the Northeastern RTOs.

What do we mean by Utility Operations?

"Utility operations" refers to the activities required to operate the utility. It is a broad term that encompasses daily activities (running power plants, managing regulatory relationships, marketing energy efficiency programs, dispatching demand response programs, running computer systems, etc.) and longer-term activities (forecasting and planning processes, finance and accounting activities, etc.). For purposes of this analysis, it can be distinguished from maintenance activities, which mainly focus on maintaining as opposed to operating the utility. The distinction is not clear-cut, but it limits the scope of items on which one might focus.

Utility operations as they relate to demand response and ARCs is an even narrower term. To the extent ARCs interact with utility operations in a similar manner to a utility's other demand response activities (and, therefore, aren't really a change in the way the utility operates), then the effect is considered limited. If ARCs require changes in the utility's operations, then such an effect is noteworthy and applicable to this study.

It is useful to further define the term "utility". In regulated states like Minnesota, utility generally refers to the vertically integrated entity that provides generation, distribution and transmission services. In deregulated states, laws require that utilities "unbundle" some of these services and act as common carriers for electricity with competitive providers responsible for providing retail electric service. Utilities acting as local distribution companies may provide default retail electric services for customers who do not choose a competitive provider. Laws and regulations may also impose energy efficiency and demand response requirements on the LDC. Although the operations of a local distribution company differ from those of a vertically integrated utility, this report assumes that "utility" in deregulated states refers to the LDC.

What do we mean by utility-operated demand response programs?

For purposes of this analysis, the term "utility-operated demand response programs" refers to demand response programs run by vertically integrated utilities or local distribution companies (LDCs).

What impacts do ARC operations have on utility operations and utility-operated demand response programs?

In conducting the research the authors sought input from utilities and ISOs/RTOs to assess whether ARC operations have an impact on utility operations or utility-operated demand response programs. Unfortunately, information from RTOs regarding utility-related operations was limited and it was difficult to obtain useful information from utilities, particularly those that were described as "active" demand response participants in RTO markets. The difficulty in obtaining information from these utilities may be an indication that utilities are reluctant to discuss issues that are considered proprietary and that they are, in fact, in competition with ARCs. The following information came from RTO representatives and those utilities that were willing to discuss these issues.

PJM Interconnection (PJM)

According to PJM staff, some utilities in the PJM area are very active with demand response, with some even marketing outside their service territories. Maryland has a large load control program and several municipalities and cooperatives are also actively participating in wholesale demand response activities. However, as noted, PJM does not distinguish between the different types of CSPs so PJM staff was not aware of effects on utility operations.

The PJM utilities with which the authors spoke claimed that ARC participation has had impacts on utility operations. Utilities are responsible for providing customer data that ARCs or CSPs need in order to register sites in PJM's demand response programs. This information includes customer account numbers, peak load contribution, capacity and energy loss factors, and confirmation regarding whether a customer has an interval meter.

Utilities usually have to approve site registrations and are responsible for providing a year's worth of customer data to the ARC/CSP for use in the baseline calculations. After load response events, utilities provide event data, so that the ARC/CSP can calculate the settlement amounts. In addition utilities review and approve settlements after demand response events and take orders for the installation of interval meters if requested by the ARC/CSP.

The utilities' ongoing efforts to provide meter data has been reduced by implementing automated systems; however, the utilities had to incur costs related to the design and build of such systems and must continue to maintain these systems.

Additionally, the utilities often had to reprioritize the smart/interval meter installation in response to requests from ARCs. Such processes do result in additional administrative burden, but additional meter costs would only be incurred if the utility did not plan to install an advanced meter for a particular customer.

The utilities further believe that large C&I customers are experienced and familiar with the available programs in the PJM market and that they readily "shop around" to get the best possible contract and payment terms; however, in some cases, there can be customer confusion since there are multiple programs offered by both ARCs and utilities.

New York Independent System Operator (NYISO)

According to NYISO staff, utilities in the NYISO control area do not have the resources to recruit customers and since the advent of deregulation, have focused on being "wires companies". In NYISO, utilities and end-use customers (direct bidding) still provide a portion of the demand response services, but these services amount to less than a third of the total resources provided. CSPs entered the market in 2000, and there are now multiple CSPs in the market. The Public Service Commission supported NYISO's programs from the beginning since utilities did not have their own demand response programs.

One of the major utilities stated that the vast majority of their demand response resources are secured via aggregators who work independently. The utility sees the aggregators as an important partner in the market. They are also an important voice in the regulatory process and have contributed substantially to NYISO DR program design. According to the utility, aggregators with a strong focus on controls and automation seem more aligned with a market that is evolving towards automated dispatch. One specific challenge identified by the utility relates to locational dispatch. Aggregators operating in a free market do not necessarily acquire load control in the network locations where the utility needs demand response. The utility is trying to change this situation via incentives or bi-lateral agreements.

The utility has also created its own distribution-level demand response program to address local reliability issues. This program is subordinate to NYISO's programs, but it also affords the utility greater flexibility in managing local loads. However, ARCs (who can recruit for the utility's programs) prefer to enroll customers in NYISO's programs, mainly because of preferable contract terms and payment conditions. Such preferences can create barriers to enrollment of resources in the utility's demand response programs.

ISO-New England (ISO-NE)

ISO-NE staff revealed that most of their demand response is also provided by non-utility ARCs/CSPs, due mainly to the fact that the bulk of ISO-NE is deregulated (~94 percent, only Vermont not). Utilities are mostly involved in energy efficiency programs but, in some states, are also encouraged to provide DR. Some utilities have their own energy programs, which are not reported to the ISO because the utilities use the resources for local reliability purposes.

The authors were able to interview one of the larger utilities in the ISO-NE area. The utility currently does not have any DR programs and has no relationships with aggregators but plans to file for a DR pilot program. Because this utility doesn't consider DR as part of its business model, the utility expects to allow ARCs to fully participate in future DR programs. The utility does have some concern that aggregator participation will cause problems on the distribution side. For example, the utility does not want its customers to have two meters installed and doesn't want to deal with customer complaints resulting from bill adjustments that the ARC/CSP may make for load reduction events.

Connecticut utilities are actively involved in ISO-NE demand response activities. According to ISO-NE, one of the state's utilities is one of the bigger demand response providers in the region. As with other deregulated utilities, though, United Illuminating has made the necessary investments and process changes to facilitate competitive provider provision of retail electric service to its customers. [61]

Changes required to accommodate ARCs

It is unclear what changes would be required for Minnesota utilities to accommodate ARC participation, although costs to enable ARCs to directly engage customers and interface with the utility could be non-trivial. The benefits, on the other hand, are less clear. The Brattle Group's *Fostering Economic Demand Response in the Midwest ISO* makes this very clear in qualifying its recommendation that MISO facilitate entry of CSPs,

[61] UI's elaborate Supplier Management System dedicated to electric suppliers/aggregators attest to this statement. http://www.sms.uinet.com/wps/portal/

> However, this recommendation is made subject to several caveats. First, the degree to which CSPs could disrupt LSE planning and trading needs to be considered. Second, the relative costs of accommodating CSPs compared with the benefits to the market must be further examined. The costs include charges to other customers, LSEs and market participants to fund payments for "negawatts" (including phony negawatts if the customer baseline load (CBL) does not accurately measure what an end-user would have consumed but for its response to price signals), increased operational costs of incorporating resources that are not fully controllable, predictable, or nodally dispatched, and administrative costs. Administrative costs include the costs of administering programs and modifying the Midwest ISO's tariff, business practices, market software, and settlement systems. (Minor modifications might be needed to allow CSPs to offer demand reductions at the same commercial pricing node as the host LSE; it will also be necessary to implement CBL and settlement mechanisms in the software. Third, payments to CSPs should avoid the issue of "double dipping," as discussed above. Determining the appropriate retail rate offset is not necessarily a straightforward matter for those end-use customers whose retail rates are not transparent to the Midwest ISO.[62]

Since the 2008 study was completed, MISO has indeed modified its tariffs to allow ARC participation (subject to FERC approval), has begun to implement required system changes, and has established mechanisms that it hopes will address the other issues Brattle raises. This study, though, focused on MISO rather than the changes that might be required at the state level and within utilities.

Difficult to assess impacts on utility operations and utility-administered demand response program in the Northeast

In conclusion it is difficult to draw conclusions about the effects of ARCs on utility operations and utility-administered demand response programs by examining Northeast RTOs because the circumstances with Northeast RTOs are very different from those in the Midwest ISO. In addition, information from utilities whose programs were likely most impacted was unavailable. Retail electricity deregulation, though, has created a different environment for aggregators (and competitive retail electric providers) and utilities have already made large-scale investments and process changes to accommodate competitive retail electric service. Further changes to accommodate ARCs are likely not substantial.

[62] "Fostering Economic Demand Response in the Midwest," p. 74.

Section 4: Recommended Next Steps

Primary data studies

This study has revealed the fact that limited information exists regarding the effects of ARCs on prices, reliability, nonparticipating customers, utility operations, and utility-administered demand response programs. It has also shown that conducting such analyses would also be quite difficult because performance data that segregate ARCs from non-ARCs is also not readily available. It may be possible to enter into confidential agreements with ARCs, RTOs and other relevant participants to be able to conduct such analyses, but such arrangements might be difficult to secure and would not necessarily yield sufficient data to draw definitive conclusions.[63]

Most importantly, the MISO's demand response activities remain in their infancy, particularly as they relate to ARCs. In the coming years, this situation will likely change because ARCs will likely begin to play more active roles in MISO markets. At that time, it might make sense to revisit the questions and determine what additional data may be available from MISO.

Another possible future study would be one that contrasts the impact of demand response between RTOs with large amounts of ARC participation and those with limited ARC participation. Unfortunately, RTOs with limited amounts of ARC participation are few because RTOs outside of the Northeast and Texas have only recently begun to actively develop and promote their demand response activities. These other RTOs include the MISO, the Southwestern Power Pool, and the California ISO. After ARCs have entered these markets, it might make sense to revisit the questions and determine what additional data may be available from other RTOs.

Pilots

The Minnesota Public Utilities Commission in its February 8, 2011 Order in Docket No. E-999/CI-09-1449 requested that utilities submit by September 1, 2011 comments "on the ability to expand demand response options through contracts with third parties in order to achieve demand response potential."[64] This approach could be one way to assess whether Minnesota ratepayers could benefit from participation by ARCs but it would help to put in place mechanisms to test the effects such tariff changes would have on the issues the PUC raises. Another way to test these issues was suggested in the PUC's May 18, 2010 Order in the same docket. In that order,

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[63] The team lead for FERC's Assessment of Demand Response & Advanced Metering indicated in conversations that their data as it relates to ARCs is limited because ARCs consider much of their data proprietary and confidential. FERC's surveys for the Assessment are voluntary. Email exchange with Dean Wight, Team Lead, Federal Energy Regulatory Commission Team, August 5, 2011.

[64] "Order Requiring Further Filings by Utilities," Minnesota Public Utilities Commission (Docket No. E-999/CI-09-1449), February 8, 2011, p. 5.

the PUC also encouraged utilities to submit pilot projects designed to "explore the potential for ARCs and other third-party providers to increase levels of demand response in Minnesota".[65]

Establishing such a pilot could address the PUC's questions by setting-up an "experiment" to test the effects of ARC participation on prices, reliability, nonparticipating customers, utility operations, and utility-administered demand response programs while meeting the PUC's other requirements.[66]

The pilot could be designed to target a specific class of customers and allow participation by multiple ARCs, with program parameters consistent with one of the MISO's demand response opportunities: Emergency Demand Response, DRR-Type 1, DRR-Type 2, etc. It would be best to focus on only one of the programs to improve data collection and ensure the ability to conform to the PUC's order points.

One model for such a pilot is the California ISO's Proxy Demand Resource proposal, which FERC conditionally approved on July 15, 2010. [67] The program compensates market participants for responding to price signals by reducing retail customers' electricity use. Demand Response Providers are allowed to participate in in the CAISO's day-ahead and real-time energy markets and certain ancillary services markets.

California's Proxy Demand Resource (PDR) mechanism could provide a good analog for Minnesota's situation because most California utility customers receive bundled loads from their utility (not deregulated).[68] The California ISO has implemented the program but there has not yet been any non-utility participation as of this writing. Due to the regulatory construct in California, there have been delays in allowing bundled customers to participate directly in the market through an ARC or otherwise outside of a utility program.

All three California utilities conducted pilots (Participating Load Pilot) to test customer participation in a utility-initiated demand resource program directly bid into the CAISO wholesale market prior to the implementation of PDR. Only one utility, SDG&E, used aggregators. This pilot allowed ARCs to participate and then tested a variety of issues. [69] It has

[65] "Order Prohibiting Bidding of Demand Response into Organized Markets by Aggregators of Retail Customers and Requiring Further Filings by Utilities," Minnesota Public Utilities Commission (Docket No. E-999/CI-09-1449), May 18, 2010, p. 7.

[66] "Order Prohibiting Bidding of Demand Response into Organized Markets by Aggregators of Retail Customers and Requiring Further Filings by Utilities," Minnesota Public Utilities Commission, pp. 7-8.

[67] "Order Conditionally Accepting Tariff Changes and Directing Compliance Filing," Federal Energy Regulatory Commission (Docket No. ER10-765-001), July 15, 2010.

[68] As a legacy of California's deregulation experience, there remain a limited number of direct access and community choice aggregation customers.

[69] "San Diego Gas & Electric Participating Load Pilot: 2009 Evaluation," San Diego Gas & Electric Company, February 1, 2010.

since given rise to another pilot, the Demand Response Wholesale Market Pilot, which uses the Proxy Demand Resource mechanism now that it has been implemented by the CAISO.[70]

Wisconsin Public Service (WPS) also provides a good example of a utility that has sought to implement programs that take advantage of MISO markets. WPS modified its legacy interruptible program to allow bidding in price responsive demand in the Midwest ISO day-ahead market. The Company's CP-I2 rate targets commercial and industrial customers with interruptible demand of 200 kW or more with customers subject to emergency and economic interruptions for a maximum of 300 hours per year for legacy DR, and 600 hours per year for new interruptible DR. Emergency interruptions are declared during system reliability events, while economic interruptions are declared when the wholesale market prices significantly exceed an established Economic Interruption Trigger Price (EITP). Customers have a "buy-through" option to specify a quantity and price at which they are willing to buy energy day-ahead instead of paying the real-time prices.[71]

[70] "San Diego Gas & Electric Report on Demand Response Integration into CAISO Wholesale Markets," San Diego Gas & Electric Company, January 31, 2011.

[71] "Fostering Economic Demand Response in the Midwest ISO," p. 6.

Conclusion

Overall conclusion regarding ARC impacts

The analysis was not able to state definitively what impact ARCs have had on prices, reliability, nonparticipating customers, utility operations, or utility-operated demand response programs. To the extent demand response has had effects on capacity prices, reliability and nonparticipating customers, one can reasonably argue that aggregators of retail customers are a primary driver of those effects in the PJM Interconnection, ISO New England, and New York ISO. This is a reasonable argument because ARCs constitute the bulk of the demand response resources (particularly the new resources) in these three RTOs. It is not clear that ARCs are necessarily large participants in day-ahead energy markets and so, based on data from ISO-NE and NYISO, it is more difficult to connect ARCs with effects on energy prices.

Such statements and arguments do not apply to the Midwest Independent Transmission System Operator because ARCs are not active participants in MISO demand response activities. In contrast with the Northeastern RTOs, MISO already has a substantial amount of demand response participation through legacy and new utility demand response programs.

Because most of the regions within MISO are still served by regulated utilities, MISO is very different from the Northeast RTOs and ERCOT and, therefore, issues such as demand response may need to be treated differently. ARCs may very well have effects on the issues raised by the Minnesota Public Utilities Commission and, at least with respect to those that can be used to objectively determine whether ARC participation should be encouraged (prices, reliability, nonparticipants), such effects may be positive (lower prices, improved reliability, no or positive effects on nonparticipants). Given the role that utilities will play in Minnesota's regulatory scheme and the presence of substantial demand response resources, Minnesota may be best served by moving towards a market structure that continues to maximize cost effective demand response participation. ARCs may be an important part of such a market, but their impact on Minnesota utility ratepayers should be further evaluated and tested.

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Appendix B – ARC Status in States

Updated August 1, 2011

STATE	DOCKET #	STATUS AT COMMISSION
Illinois		No opt out – allows aggregators
Indiana	43566	7/28/10 - Order prohibits end-use customers from directly participating in RTO DR programs w/o prior PSC approval – allows participation through LSE approved tariffs.[72]
Iowa	NOI-2008-0003	3/29/10 – Order prohibiting ARCs
Michigan	U-16020	12/10/10 - Temporary ban with clarification on 2/22/11 stating that ban doesn't apply to 2 existing PJM customers for term of current contracts.
Minnesota	CI-09-1449	5/18/10 - Order prohibits ARC participation but requires filings from utilities. Latest filings are due 9/1/11.
Missouri	2010-187	3/31/10 - Order temporarily prohibiting; have held multiple workshops and have begun to develop draft rules to, among other things, potentially allow ARCs to participate in MO.
North Dakota	PU-10-59	8/24/10 – Order prohibits ARCs unless rate schedule under which customer receives service allows sales for resale.
Ohio		No opt out – allows aggregators
South Dakota	EL10-0003	5/25/10 – Prohibit ARC participation in market until further notice.
Wisconsin	5-UI-116	10/15/09 – Order temporarily prohibiting ARCs

Table based on information provided by Midwest Independent System Operator.

[72] "The Commission instead ordered NIPSCO and the other Indiana jurisdictional electric utilities (collectively the "Respondent Utilities") to file with the Commission for approval tariffs or riders authorizing the participation of their respective retail customers in RTO demand response programs through the Respondent Utilities. The Commission initiated two subdockets, one for MISO utilities and one for PJM utilities, to consider development of these tariffs." Case No. 43566, March 2, 2011, p. 2.

Appendix C – 2010 RTO Demand Response Programs[73]

ISO/RTO Product / Service						*Product / Service Features*							
Region	**Acronym**	**Name**	**Service Type**	**Begin Date**	**End Date**	**Minimum Eligible Resource Size**	**Minimum Reduction Amount**	**Aggregation Allowed**	**Participa-tion**	**Response Required**	**Primary Driver**	**Deployment "Overuse" Restriction**	**"Peak" Hours Only**
ISO-NE													
ISO-NE	**RTDRP**	Real Time Demand Response Program [Capacity Component]	Capacity	Active	5/31/10	100 kW	100 kW	Yes	Voluntary	Mandatory	Reliability	None	No
ISO-NE	**RTDRP**	Real Time Demand Response Program [Energy Component]	Energy	Active	5/31/10	100 kW	100 kW	Yes	Voluntary	Mandatory	Economic	None	No
ISO-NE	**DALRP / RTDR**	Day-Ahead Load Response Program for RTDRP	Energy	Active	None	100 kW	100 kW	Yes	Voluntary	Mandatory	Economic	None	Yes
ISO-NE	**DALRP / RTPR**	Day-Ahead Load Response Program for RTPR	Energy	Active	None	100 kW	100 kW	Yes	Voluntary	Mandatory	Economic	None	Yes
ISO-NE	**DRR**	Demand Response Reserves Pilot	Reserve	Active	5/31/10	100 kW	100 kW	Yes	Voluntary	Mandatory	Reliability	None	No
ISO-NE	**RTPR**	Real Time Price Response Program	Energy	Active	None	100 kW	100 kW	Yes	Voluntary	Voluntary	Economic	None	Yes
ISO-NE	**RTDR**	Real Time Demand Response Resource	Capacity	Quals Active, Delivery starting 2010-06-01	None	100 kW	1 kW	Yes	Voluntary	Mandatory	Reliability	None	No
ISO-NE	**OP**	FCM: On-Peak Demand Resources	Capacity	Quals Active, Delivery starting 2010-06-01	None	100 kW	1 kW	Yes	Voluntary	Mandatory	Reliability	None	Yes
ISO-NE	**SP**	FCM: Seasonal Peak Demand Resources	Capacity	Quals Active, Delivery starting 2010-06-01	None	100 kW	1 kW	Yes	Voluntary	Mandatory	Reliability	None	Yes
ISO-NE	**RTEG**	Real Time Emergency Generation Resource	Capacity	Quals Active, Delivery starting 2010-06-01	None	100 kW	1 kW	Yes	Voluntary	Mandatory	Reliability	None	No
ISO-NE	**DARD**	Dispatchable Asset Related Demand	Reserve	Active	None	1 MW	1 kW	Yes	Voluntary	Mandatory	Economic	None	No

[73] Midwest ISO doesn't have "programs" per se. MISO facilitates demand response participation in existing markets but does not sponsor programs.

ISO/RTO Product / Service						Product / Service Features							
Region	Acronym	Name	Service Type	Begin Date	End Date	Minimum Eligible Resource Size	Minimum Reduction Amount	Aggregation Allowed	Participa-tion	Response Required	Primary Driver	Deployment "Overuse" Restriction	"Peak" Hours Only
MISO													
MISO	DRR-I	Demand Response Resource Type I (Energy)	Energy	Active	2010-05-31 (Pending FERC Approval)	1 MW		Yes	Voluntary	Voluntary	Economic	Biddable Daily Participation	No
MISO	DRR-I	Demand Response Resource Type I (Energy)	Energy	2010-06-01 (pending FERC approval)	None	1 MW		Yes	Voluntary	Voluntary	Economic	Biddable Daily Participation	No
MISO	DRR-I	Demand Response Resource Type-I (Reserve)	Reserve	Active	2010-05-31 (Pending FERC Approval)	1 MW		Yes	Voluntary	Mandatory	Economic	Biddable Daily Participation	No
MISO	DRR-I	Demand Response Resource Type-I (Reserve)	Reserve	2010-06-01 (pending FERC approval)	None	1 MW		Yes	Voluntary	Mandatory	Economic	Biddable Daily Participation	No
MISO	DRR-II	Demand Response Resource Type II (Energy)	Energy	Active	2010-05-31 (Pending FERC Approval)	1 MW		No	Voluntary	Voluntary	Economic	Biddable Daily Participation	No
MISO	DRR-II	Demand Response Resource Type II (Energy)	Energy	2010-06-01 (pending FERC approval)	None	1 MW		No	Voluntary	Voluntary	Economic	Biddable Daily Participation	No
MISO	DRR-II	Demand Response Resource Type-II (Reserve)	Reserve	Active	2010-05-31 (Pending FERC Approval)	1 MW		No	Voluntary	Mandatory	Economic	Biddable Daily Participation	No
MISO	DRR-II	Demand Response Resource Type-II (Reserve)	Reserve	2010-06-01 (pending FERC approval)	None	1 MW		No	Voluntary	Mandatory	Economic	Biddable Daily Participation	No
MISO	DRR-II	Demand Response Resource Type-II (Regulation)	Regulation	Active	None	1 MW		No	Voluntary	Mandatory	Economic	Biddable Daily Participation	No
MISO	EDR	Emergency Demand Response	Energy	Active	None	100 kW		Yes	Voluntary	Voluntary	Reliability	Biddable Daily Participation	No
MISO	LMR	Load Modifying Resource	Capacity	Active	None	100 kW		Yes	Voluntary	Mandatory	Reliability	Minimum use 5x	No

ISO/RTO Product / Service						Product / Service Features								
Region	Acronym	Name	Service Type	Begin Date	End Date	Minimum Eligible Resource Size	Minimum Reduction Amount	Aggregation Allowed	Participa-tion	Response Required	Primary Driver	Deployment "Overuse" Restriction	"Peak" Hours Only
NYISO													
NYISO	DADRP	Day-Ahead Demand Response Program	Energy	Active	None	1 MW	1 MW	Yes	Voluntary	Mandatory	Economic	None	No
NYISO	DSASP	Demand Side Ancillary Services Program	Reserve	Active	None	1 MW	1 MW	No	Voluntary	Mandatory	Economic	None	No
NYISO	DSASP	Demand Side Ancillary Services Program	Reserve	Active	None	1 MW	1 MW	No	Voluntary	Mandatory	Economic	None	No
NYISO	DSASP	Demand Side Ancillary Services Program	Regulation	Active	None	1 MW	1 MW	No	Voluntary	Mandatory	Economic	None	No
NYISO	EDRP	Emergency Demand Response Program	Energy	Active	None	100 kW (per Zone)	100 kW (per Zone)	Yes	Voluntary	Voluntary	Reliability	None	No
NYISO	SCR	Installed Capacity Special Case Resources (Energy Component)	Energy	Active	None	100 kW (per Zone)	100 kW (per Zone)	Yes	Voluntary	Mandatory	Reliability	None	No
NYISO	SCR	Installed Capacity Special Case Resources (Capacity Component)	Capacity	Active	None	100 kW (per Zone)	100 kW (per Zone)	Yes	Voluntary	Mandatory	Reliability	None	No

ISO/RTO Product / Service						Product / Service Features							
Region	Acronym	Name	Service Type	Begin Date	End Date	Minimum Eligible Resource Size	Minimum Reduction Amount	Aggregation Allowed	Participa-tion	Response Required	Primary Driver	Deployment "Overuse" Restriction	"Peak" Hours Only
PJM													
PJM	-	Economic Load Response (Energy)	Energy	Active	None	100 kW	100 kW	Yes	Voluntary	Voluntary	Economic	Biddable Daily Participation	No
PJM	-	Economic Load Response (Synchronized reserves)	Reserve	Active	None	500 kW	500 kW	Yes	Voluntary	Mandatory	Reliability	Biddable Hourly Participation	No
PJM	-	Economic Load Response (Day ahead scheduling reserve)	Reserve	Active	None	500 kW	500 kW	Yes	Voluntary	Mandatory	Reliability	Biddable Hourly Participation	No
PJM	-	Economic Load Response (Regulation)	Regulation	Active	None	500 kW	500 kW	Yes	Voluntary	Mandatory	Reliability	Biddable Hourly Participation	No
PJM	-	Emergency Load Response - Energy Only	Energy	Active	None	100 kW	100 kW	Yes	Voluntary	Voluntary	Economic	None	No
PJM	-	Full Emergency Load Response (Capacity Component)	Capacity	Active	None	100 kW	100 kW	Yes	Voluntary	Mandatory	Reliability	10 days up to 6 hours per day	Yes
PJM	-	Full Emergency Load Response (Energy Component)	Energy	Active	None	100 kW	100 kW	Yes	Voluntary	Mandatory	Reliability	10 days up to 6 hours per day	Yes

Source: "North American Wholesale Electricity Demand Response 2010 Comparison," ISO/RTO Council, May 17, 2010.

CERTIFICATE OF SERVICE

I, Lindsey Didion, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota

xx electronic filing

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Dated this 1st day of September 2011

/s/

Lindsey Didion
Administrative Assistant

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	No	OFF_SL_9-1449_Official
Keith L.	Beall	kbeall@midwestiso.org	Midwest ISO Legal Dept.	P.O. Box 4202 Carmel, IN 46082	Paper Service	No	OFF_SL_9-1449_Official
Peter	Beithon	pbeithon@otpco.com	Otter Tail Power Company	P.O. Box 496 215 South Cascade Street Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_9-1449_Official
Michael	Bradley	bradleym@moss-barnett.com	Moss & Barnett	4800 Wells Fargo Ctr 90 S 7th St Minneapolis, MN 55402-4129	Electronic Service	No	OFF_SL_9-1449_Official
Brian	Draxten		Otter Tail Power Company	P.O. Box 496 215 South Cascade Street Fergus Falls, MN 565380498	Paper Service	No	OFF_SL_9-1449_Official
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	Yes	OFF_SL_9-1449_Official
Ronald M.	Giteck	ronald.giteck@ag.state.mn.us	Office of the Attorney General-RUD	Residential Utilities Division 445 Minnesota Street, 900 BRM Tower St. Paul, MN 55101	Paper Service	No	OFF_SL_9-1449_Official
Burl	Haar	burl.haar@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 55101-2147	Electronic Service	No	OFF_SL_9-1449_Official
Lori	Hoyum	lhoyum@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	OFF_SL_9-1449_Official
Paula N.	Johnson		Interstate Power and Light Company	200 First Street SE PO Box 351 Cedar Rapids, IA 524060351	Paper Service	No	OFF_SL_9-1449_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Jeffrey L.	Landsman	jlandsman@wheelerlaw.com	Wheeler, Van Sickle & Anderson, S.C.	Suite 801 25 West Main Street Madison, WI 537033398	Paper Service	No	OFF_SL_9-1449_Official
John	Lindell	agorud.ecf@state.mn.us	Office of the Attorney General-RUD	900 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	No	OFF_SL_9-1449_Official
John	McWilliams	jmm@dairynet.com	Dairyland Power Cooperative	3200 East Ave SPO Box 817 La Crosse, WI 54601-7227	Electronic Service	No	OFF_SL_9-1449_Official
Andrew	Moratzka	apm@mcmlaw.com	Mackall, Crounse and Moore	1400 AT&T Tower 901 Marquette Ave Minneapolis, MN 55402	Paper Service	No	OFF_SL_9-1449_Official
SaGonna	Thompson	Regulatory.Records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_9-1449_Official
Mona	Tierney-Lloyd	mtierney-lloyd@enernoc.com	EnerNoc Inc	P. O. Box 378 Cayucos, CA 93430	Paper Service	No	OFF_SL_9-1449_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	No	OFF_SL_11-588_M-11-588
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	Yes	OFF_SL_11-588_M-11-588
Burl W.	Haar	burl.haar@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_11-588_M-11-588
John	Lindell	agorud.ecf@state.mn.us	Office of the Attorney General-RUD	900 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	No	OFF_SL_11-588_M-11-588
SaGonna	Thompson	Regulatory.Records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_11-588_M-11-588