FERC Policy on Demand Response and Order 719

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Abstract

On October 17, 2008, the Federal Energy Regulatory Commission (FERC) issued a Final Rule on "Wholesale Competition in Regions with Organized Electric Markets" in Docket Nos. RM07-19-000 and AD07-7-000.; Order 719. The Final Rule addresses four specific topic where reforms may advance the operation of organized wholesale markets. This article explores only the demand response proposals issued by FERC. This article argues that the FERC vision of bid-in, dispatchable demand response, aggregated and sold at the wholesale level may incentivize centrally controlled DR products that operate only during events, under contracts, or under utility tariff programs. The FERC policy may very well discourage efficient active demand response which is driven by a price, or value signal not an incentive payment. This article also explores the requirement to modify market rules to permit Aggregated Retail Customers (ARCs) to bid demand response directly into the organized wholesale energy requirements arguing that the FERC has long contemplated such a requirement, viewing demand response as a wholesale market transaction and thus within FERC jurisdiction under the Federal Power Act (FPA). Furthermore, this article argues that the FERC required modification of market rules to allow ARCs to bid directly create significant jurisdictional concerns for States within less mature markets such as Midwest Independent System Operator (MISO) and California.

RECENT FEDERAL ENERGY REGULATORY COMMISSION ACTION ON DEMAND RESPONSE

FERC's Final Rule 719 on *Wholesale Competition in Region with Organized Electric Markets* requires "RTOs and ISOs to amend their market rules as necessary to permit an ARC to bid demand response on behalf of retail customers directly into the RTOs or ISOs organized markets, unless the laws or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate."[1] FERC's Rule has greatest implications for the two ISOs that do not currently have a direct bid-in option for demand response. While the California ISO (CAISO) currently allows Participating Load, a demand response resource, to bid directly into their organized markets, only the large California Department of Water Resources pump load is capable of meeting the technical requirements.[1] The MISO does not currently allow demand response resources to bid demand response megawatts direct into their organized markets. Demand response in the MISO states is State run, through "legacy programs."[2] Of the roughly 2700

[1] For technical standards see http://www.caiso.com/docs/2001/01/22/200101221153242073.pdf. The California ISO recently posted a straw supplement to allow demand response resources with 15 minute and 1 hour interval metering to bid into their organized markets. However, this straw proposal has not been approved by CAISO Board of Directors or been submitted to the FERC for approval. *See* http://www.caiso.com/1c91/1c919e0e11c30.pdf.

[2] States within MISO have made demand resources available for the benefit of reducing demand for load serving entities (LSE) for a number of years. These demand response programs were created at the state level through load control mechanisms, interruptible tariffs, or special contracts. These demand response programs are referred to as "legacy" demand response. *See Comments of the Organization of MISO States on Advance Notice of*

MW of demand response in California all are attributed to State regulated, IOU administered, demand response programs.

FERC's requirement that RTO and ISO market rules be amended to permit ARCs to bid directly into the wholesale market is arguably an attempt to create a RTO/ISO FERC jurisdictional demand response market. Such a demand response market system would parallel the State run demand response initiatives. However, FERC's new parallel demand response market may arguably be outside the reach of the State regulatory authority. This would mean that some actions of ARCs, to aggregate end-user customer load, if not already regulated by the State may be, hereafter, outside the control of State regulation. A brief history of FERC decisions and discussions involving demand response can help clarify.

In Short

Looking back on FERC decisional history, it can be seen that FERC has attempted to define demand response as within FERC's jurisdiction. The FERC's primary rationale for exercising jurisdiction over RTO/ISO demand response has been that demand response involves an excess sale of energy for resale at the wholesale level. In essence, the decision by the end-use customer to curtail usage means that the load serving entity did not need to purchase those kilowatts to serve that customer. Therefore the kilowatts never left the wholesale market or the jurisdiction of the FERC. If the LSE did not sell those kilowatts to the end-user then the energy is still available for bid at the wholesale level.

FEDERAL ENERGY REGULATORY COMMISSION'S JURISDICTIONAL ARGUMENT

On March 14, 2001 in *Removing Obstacles Order*[3], the FERC granted permission to wholesale customers to reduce consumption for the purposes of reselling their load reduction at wholesale.[4] The Commission granted a blanket authorization to allow these sales at market-based rates. In doing so, the Commission began to define the characteristics of these transactions that make them wholesale transactions, "These transactions are considered wholesale when they involve the sale for resale of energy that would ordinarily be consumed by the reseller."[5] Furthermore, the FERC went on to state-

These transactions can occur in several ways. An aggregator can line up retail load to acquire enough megawatts to resell in a manner similar to what aggregators do when they sell power to retail load under retail choice programs. In addition, wholesale and retail load with contract demand service could resell their contract demands if the value of power is greater than the value of consumption.[6]
This is an early regulatory concept of Demand Response.

It is important to note that in this 2001 Order FERC[7] assimilates aggregator retail practices with wholesale practices. Yet what the FERC glosses over is the fact that in States where aggregators operate to resale retail load through retail choice programs the practices of those aggregators are directly impacting end-users who are protected through State regulatory oversight of load serving

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Proposed Rulemaking to Docket Nos. RM07-19-000 and AD07-7-000, pg. 3-4, http://www.misostates.org/MinutesOMSBoDmtg13Sept2007withAttachmentsApproved.pdf (2007).

[3] *Removing Obstacles to Increase Electric Generation and Natural Gas Supply in the Western United States,* 94 FERC ¶61,272 (2001). (In the order, the FERC requested comments from the State PUC's on the issue of demand response and issue of jurisdiction.)
[4] *Id.*, at 61,970.
[5] *Id.*, at 61,970.
[6] *Id.*
[7] *Removing Obstacles to Increase Electric Generation and Natural Gas Supply in the Western United States,* 94 FERC ¶61,272 (2001).

entities; little or no regulation by Sates of aggregators who aggregate retail demand currently exists or is contemplated.

The Commission reiterated its position later that same year in a PJM Interconnection Order[8] again asserting that demand response transactions are wholesale transactions "when they involve the sale for resale of energy that would ordinarily be consumed by the [retail customer]."[9] However, the FERC caveats its authority stating that it is "not encouraging actions that violated state laws or regulations."[10]

In *Order on Requests for Clarification and Rehearing*[11] of *Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States*, the FERC noting confusion over when a sale is retail or wholesale in a demand response scenario, structured a more formal definition of when a demand response transaction is wholesale. The Commission stated-

Transactions involving purchases of demand reduction are considered wholesale when they involve the sale for resale of energy that would ordinarily be consumed by the retail customer. We recognize that there is a fine line separating state and federal jurisdiction where a retail customer receives compensation for a load reduction. Where a supplier directly compensates its retail customer for load reduction, *state jurisdiction is indicated.* Where there are third parties involved, particularly where the transaction is tied to markets within our jurisdiction, then load reduction transactions *where the seller is a public utility would fall within our jurisdiction.*[12] [Emphasis Added].

The Commission went on to state that its intent is not to undermine existing state demand side management programs, but to promote complementary wholesale programs.[13]

In an Order issued March 13, 2002, the Commission granted authorization and waivers to the New York Independent System Operator (NYISO) to implement a demand response program.[14] The New York State Energy and Gas Corporation (NYSEG) requested clarification regarding the Commission's jurisdiction over demand response transactions, specifically asking the Commission to clarify "that sales of power deemed to be made by a load serving entity (LSE) to its customers that participate in NYISO's demand response programs are not Commission-jurisdictional sales for resale, but rather are State-jurisdictional retail sales."[15] The Commission clarified-the Commission may deem a load reduction arrangement to involve two separate and independent transactions: the first being a 'sale for resale' of power by the LSE to a retail customer that is participating in the programs (by generating electricity or reducing its electric consumption) (the Retail Sale), and the second involving the participating retail customer's sale of power back to NYISO and the LSE, which was also viewed by the Commission as a sale for resale (the Program Sale).[16]

Here we begin to see FERC carving out two separate, possibly complimentary or parallel demand response markets. The FERC names one

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[8] *PJM Interconnection Order Accepting Tariff Sheets As Modified,* 95 FERC ¶61,306 (May 2001).
[9] *Id.,* at 62,043.
[10] *Id.*
[11] *Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States, Order on Requests for Clarification and Rehearing,* 95 FERC ¶ 61,155 (July 2001)
[12] *Removing Obstacles to Increased Electric Generation and Natural Gas Supply In the Western United States,* 96 FERC ¶61,155 at 61,679 (2001).
[13] *Id.*
[14] *New York Independent System Operator,* 98 FERC ¶61,268 (2002).
[15] *Id.,* at 62,041.
[16] *Id.*

side of the transaction "the Retail Sale."[17] The "Retail Sale" is the end-user sale of demand response kilowatts to the LSE. It seems however that whenever demand response is aggregated by the LSE or customer for eventual sale in the wholesale market is then called a "Program Sale" and is therefore within the jurisdiction of the FERC. This is a very fine point but it essentially means that demand response programs that a utility uses simply to maintain distribution reliability are within the State jurisdiction. However once the LSE uses demand response curtailments as and economic mechanism, for eventual bid in the wholesale market, the transactions become the jurisdiction of the FERC.

In a PJM Interconnection Order dated April 2002, the Commission formally adopted the view that the Program Sale is within its jurisdiction because "the end user is 'selling' the energy that it would otherwise purchase. The sale is to another party who will then reuse that energy to serve other entities."[18] The Commission added that demand response programs are within FERC jurisdiction, because of their oversight over the transmission of electric energy in interstate commerce.[19] Ultimately, the Commission concluded that PJM's Emergency Load Response Program, was a tool enabling PJM to maintain transmission reliability during periods of capacity shortage, within FERC's jurisdiction.[20]

In May of 2002, the Commission further justified its exercise of jurisdiction by adding, with respect to PJM's emergency load response program, the absence of demand side response was a flaw in the markets by PJM which, if not corrected, could lead to dysfunction in those markets, and the Load Response Program is part of PJM's attempt to correct that dysfunction. PJM's markets are within our jurisdiction, *and the Load Response Program is thus within our jurisdiction as well.*[21] [Emphasis Added].

The Commission encouraged States to engage in collaborative efforts toward removing barriers to the implementation of demand response programs.[22] In finding PJM's Economic Load Response Program just and reasonable, the Commission rejected the view that "the [independent system operator] is forced to work under the assumption that all customers have an inelastic demand for energy and will pay any price for power."[23] Instead, the Commission determined that customers, with the right tools, can and will manage their electricity demand.[24] From a policy perspective, the Commission concluded that price signals to customers help to "mitigate market power as high supply bids are more likely to reduce the bidders' energy sales. Suppliers thus have additional incentive to keep bids close to their marginal production costs. Demand-side price-responsiveness bids will also help to allocate scarce supplies efficiently."[25] The author of this article finds these points valid.

CHAIRMAN WELLINGHOFF AND THE CASE OF FERC ORDER 719

The FERC's previous assertions of jurisdiction over demand response were the impetus for FERC Commissioner Wellinghoff's recent statements in an Energy Law Journal article, entitled *Recognizing the Importance of Demand Response: The Second Half of the Wholesale Electric Market Equation.*[26] Here, Commissioner

[17] *Id.*
[18] *PJM Interconnection, Order Accepting Tariff Sheets as Modified,* 99 FERC ¶61,139 at 61,573 (2002).
[19] *Id.*
[20] *Id.*
[21] *PJM Interconnection, Order Accepting Tariff Sheets as Modified,* 99 FERC ¶61,227 at 61,938 (2002).
[22] *Id.*
[23] *Id.,* at 61,939.
[24] *Id.*
[25] *Id.*
[26] Jon Wellinghoff and David L. Morenoff, *Recognizing The Importance of Demand Response: The Second Half of The*

Wellinghoff explicitly states his view that FERC has jurisdiction over demand response because "the Commission's statutory responsibilities justify its playing a role in regulating those resources."[27] To justify FERC's jurisdiction over demand response, Commissioner Wellinghoff states that "because demand response directly and significantly affects wholesale rates, facilitating demand response is essential to the Commission fulfilling its responsibility for ensuring that those rates are just and reasonable."[28] Wellinghoff goes on to state that "to the extent that demand response can be characterized as involving a wholesale sale of electric energy in interstate commerce, it would fall within the Commission's jurisdiction."[29] Commissioner Wellinghoff essentially echoes the Commission's statement to the NYISO and PJM in 2002, that to ensure just and reasonable rates demand response is within FERC jurisdiction. Ultimately, Commissioner Wellinghoff states that "Commission regulation of demand response and other distributed resources is warranted to prevent undue discrimination."[30]

Commissioner Wellinghoff's statement on FERC jurisdiction over demand response and possibly other distributed resources is far more inclusive then the original assertions made by the Commission in previous orders. These assertions of jurisdiction over demand response by Commissioner Wellinghoff are reshaped in the 2008 rule making which is the subject of this article.

In his article, Commissioner Wellinghoff notes arguments raised against FERC jurisdiction, and in favor of State jurisdiction, over demand response and distributed generation. A noted argument is that the FERC has no jurisdiction over demand response and other distributed resources because these resources fall within the "traditional and statutory jurisdiction of the States or that demand response involves a 'retail sales transaction or retail energy demand transaction over which only the states have jurisdiction" because the Federal Power Act (FPA) does not convey authority to FERC in these areas.[31] Yet his answer seems incomplete, asserting that the FERC will not impede on State rules on demand response where such exist.

Taken as a whole, the previous discussion gives pause when one considers the FERC's recent Final Rule, *Wholesale Competition in Regions with Organized Electric Markets*[32]. In this Final Rule, the FERC requires RTOs and ISOs to amend their market rules as necessary to permit an ARC (an entity aggregating demand response megawatts) to bid demand response on behalf of retail customers directly into the RTO's or ISO's organized markets.[33] While this statement is qualified by the statement- "unless the laws or regulations of the relevant electric regulatory authority do not permit a retail customer to participate,"[34] no state currently has rules or regulations directly on point. Nor does any State have rules that protect or regulate the relationship between the demand response aggregator and the end-use customer, nor does the FERC.

FERC'S EXERCISE OF JURISDICTION WILL HAVE VARIOUS UNINTENDED CONSEQUENCES. THE CALIFORNIA MARKETS PROVIDE ONE SUCH EXAMPLE

Wholesale Electric Market Equation, 28 Energy L.J. 389 (2007).

[27] *Id.*, at 396.

[28] *Id.*

[29] *Id.*

[30] *Id.*

[31] *Id.*, at 397.

[32] Final Rule- Wholesale Competition in Regions with Organized Electric Markets, Docket Nos. RM07-19-000 and AD07-7-000, 125 FERC ¶61,071 (October 17, 2008).

[33] *Removing Obstacles to Increase Electric Generation and Natural Gas Supply in the Western United States*, Docket Nos. RM07-19-000 and AD07-7-000, at ¶128. 125 FERC ¶ 61,071

[34] *Id.*

In a 1997 direct access case, the CPUC stated, in an appendix outlining the terms and conditions that apply to both the customer and the electric service providers who participate in Direct Access, "[Electric Service Providers] ESPs providing electric power shall have one or more Scheduling Coordinators, with no more than one Scheduling Coordinator per service account, for the purposes of reporting all the ESP's end-use meter reading to the ISO."[35] Meaning that in order to track scheduling and economic transactions the state would limit customer meter representation to only one service provider. A question to ask is whether an ARC is similar enough to a service provider? The CAISO mirrored this ruling by placing a similar requirement in their operating Tariff.[36] The pertinent section of the Tariff states that "only one scheduling coordinator may register with CAISO for the meter or Meter Point…"[37] Scheduling Coordinators essentially submit energy bids and schedules to the CAISO on behalf of their customers. Both LSEs and ESPs use Scheduling Coordinators to submit schedules and bids to the CAISO on their behalf. To mitigate gaming, market manipulation and scheduling confusion as seen during the California energy crisis the California Public Utilities Commission instituted this rule.[38] With the recent Wholesale Competition Rulemaking by the FERC, the Commission has opened the wholesale market to demand response aggregators. These aggregators aggregate retail demand response and would therefore be submitting bids to the wholesale market either themselves or through a scheduling coordinator. This scenario, encouraged by the FERC, would be in direct violation of the One SC per Meter rule adopted by the California Public Utilities Commission. Remember the language of the Wholesale Competition Rulemaking states that the wholesale market operator must open the market to demand response unless, "the laws or regulations of the relevant electric retail regulatory authority do not permit a retail customer to participate."[39] The California One SC per Meter rule was not written in contemplation of demand response entities. It was written to control and track the sale of energy to retail customers. Therefore it is not a direct barrier to aggregators bidding demand response into the wholesale market, because the One SC per Meter rule is based on a sale of energy flowing downward to the end-use custome, not a transaction flowing upward from the customer to the wholesale market. Therefore FERC's action has potentially placed California in jeopardy. FERC's Rule 719 encourages a challenge to the one SC per meter rule. Worse yet is the potential for a parallel demand response market encouraged by FERC yet not contemplated or regulated by the State.

Further compounding the issue, the FERC in 2006 investigated whether CAISO had unreasonably delayed work on amending its Tariff to allow more than one scheduling coordinator per meter as directed by the Commission in an October 1997 Order.[40] In the 2006 *Order Addressing Outstanding Issues Relating to California Independent System Operator Corporation*[41], the

[35] *Order Instituting Rulemaking on the Commission's Proposed Policies Governing Restructuring California's Electric Service Industry and Reforming Regulation; Order Instituting Investigation on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation,* Decision No. 97-10-087, Rulemaking No. 94-04-031 (Filed April 20, 1994), Investigation No. 94-04-032 (Filed April 20, 1994), 76 CPUC 2d 287 (Oct. 30, 1997).

[36] California Independent System Operator FERC Electric Tariff Amended and Restated Third Replacement Vol. No. 1 section 4.5.1.1.3, available at http://www.caiso.com/1c78/1c7881ed6bec0.pdf (2007).

[37] *Id.*

[38] *Supra* note 36.

[39] *Supra* Note 1.

[40] *Order Conditionally Authorizing Limited Operation of an Independent System Operator and Power Exchange,* 81 FERC ¶61,122 at 61,509 (1997).

[41] *Order Addressing Outstanding Issues Relating to California Independent System Operator Corporation,* 115 FERC ¶61,300 (2006).

FERC, finding that CAISO had not complied with the October 1997 Order, directed CAISO to "either develop the software necessary to implement the Tariff revision ordered by the Commission or to propose alternatives."[42] The disconnect between the One Sc per Meter Rule, the Wholesale Market Competition rule has not been resolved. Recently the CAISO issued a report outlining the many barriers to direct wholesale market participation of demand response.[43]

In 2008 the CAISO began measures to amend its operations Tariff to comply with FERC's directive to allow direct participation of demand response resources into the market. The CAISO defines direct participation as the ability for end-use customers or Aggregators of Retail Customers (ARCs) to offer demand response resources into the CAISO's wholesale electricity markets, through a Scheduling Coordinator, assuming all established requirements and regulations of the CAISO and of the Local Regulatory Authority have been met and any required coordination with the load-serving entity satisfied."[44] In November 2006 the CAISO initiated a stakeholder process to begin receiving direction and input from various market stakeholders on wholesale market inclusion of Demand Response.[45] Five work groups were created each led by either the CAISO, the California Energy Commission (CEC) or the California Public Utilities Commission (CPUC).[46] The Vision for Demand Response Work Group led by the states regulatory agency, the CPUC, created a Vision for Demand Response document.[47] This document calls for direct participation of demand response resources into CAISO's wholesale electricity markets, "Customers who have the ability should have the choice to sell their demand response to a Demand Response Provider or to the CAISO."[48] Given the endorsement of the Vision for Demand Response document by the California Public Utilities Commission and the California Energy Commission the CAISO began creating several products for demand response participation in the wholesale energy markets. These products are defined mostly by the technical and reporting capabilities of the various demand response resources being offered to the wholesale market. For those resources capable only of day-head event notification with broad geographical dispatch CAISO created a product called Non-participating Load.[49] For demand response resources capable of day-of dispatch with various utility sub-region geographical definition the CAISO proposed a product known as Proxy Demand Resource.[50] For demand response resources capable of node geographical reporting, dispatchable in near real-time with real-time telemetry and metering the CAISO create a product called Dispatchable Demand Response.[51]

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[42] *Id.*, at 62,077.

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[44] *Issue Paper, Direct Participation of Demand Response Resources in CAISO Electrical Markets*, December 22, 2008, available at http://www.caiso.com/20a5/20a5e36d2a40.pdf

[45] MRTU Workshop on Demand Response, Agenda November 2, 2006, Available at http://www.caiso.com/1893/1893e40a3dc10.pdf

[46] See, Demand Response Initiative Archive, Available at http://www.caiso.com/1cbb/1cbbc8ec52810.html

[47] See, *California Demand Response: A Vision for the Future*; Available at http://www.caiso.com/1fe3/1fe3ebb5d860.pdf

[48] *California Demand Response: A Vision for the Future*, page 2. Available at http://www.caiso.com/1fe3/1fe3ebb5d860.pdf

[49] See *Draft Final Proposal: Post-Release 1 MRTU Functionality for Demand Response*, Presentation by Jim Price, Lead Engineering Specialist Market and Product Development, Stakeholder and Demand Response Working Group November 5, 2008. Available at http://www.caiso.com/2074/2074e67d2a600.pdf

[50] See *Draft Final Proposal: Post-Release 1 MRTU Functionality for Demand Response*, Presentation by Jim Price, Lead Engineering Specialist Market and Product Development, Stakeholder and Demand Response Working Group November 5, 2008. Available at http://www.caiso.com/2074/2074e67d2a600.pdf

[51] See *Draft Final Proposal: Post-Release 1 MRTU Functionality for Demand Response*, Presentation by Jim

All these products are designed to include demand response participation in the CAISO wholesale electricity markets. All are compliant with the FERC's Orders to open the California wholesale energy market to direct participation of aggregated demand response.[52] While significant barriers do exist to direct participation of demand response resources in the California wholesale electricity markets, what FERC and the CAISO have made available through the FERC Orders and the CAISO stakeholder process is a marketplace for demand response unregulated by California's regulatory agencies. Currently no regime is in place to protect end-users who wish to sell directly or enter into contract(s) with aggregators or ARCs to sell demand response megawatts. This jeopardy situation is a direct consequence forced on the States by FERC actions to open the markets prematurely without proper coordination with the States.

Why

Currently most demand response resources in California are controlled by the three regulated investor owned utilities. The CPUC controls how these programs function and are structured through their regulatory authority over the States three IOUs; Pacific Gas and Electric (PG&E), Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E). The role of demand response aggregators in the state of California is overseen indirectly through the CPUC's power to regulate demand response through the investor owned utilities. Several demand response aggregators or ARCs operating in California have signed contracts for aggregated demand response with both PG&E and SCE.[53] These contracts pay for both capacity and energy supplied by demand response resources under contract to the aggregator who then sells the product to the utility. The contract between the aggregator and the end-use consumer is an unknown.[54] This relationship between the aggregator and the end-use customer is currently unregulated in California. Because this relationship between the aggregator and the end-use customer is not directly regulated or overseen by any state agency this article foresees that actions of the FERC to open the wholesale market to direct participation of demand response resources supplied by aggregators has ignored and potentially created jeopardy for end-user, ratepayer abuse at the hands of entities which are not directly under the jurisdiction of the state energy regulator.

Currently, in California, a number of barriers exist to wholesale market inclusion of demand response resources. As previously discussed, one barrier, is the current California one scheduling coordinator per meter rule and how this rule may apply to aggregator controlled demand response megawatts being bid into the wholesale market.[55] The CAISO, in a recent report, noted several other barriers including the availability of a revenue stream for directly bid demand response.[56] The CAISO does not operate a capacity market as some other independent system operators. This problem is further compounded by the fact that

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Price, Lead Engineering Specialist Market and Product Development, Stakeholder and Demand Response Working Group November 5, 2008. Available at http://www.caiso.com/2074/2074e67d2a600.pdf

[52] *Order Addressing Outstanding Issues Relating to California Independent System Operator Corporation*, 115 FERC ¶61,300 (2006) and *Final Rule- Wholesale Competition in Regions with Organized Electric Markets*, Docket Nos. RM07-19-000 and AD07-7-000, 125 FERC ¶61,071 (October 17, 2008).

[53] Proceeding Number that approved the contracts.

[54] Decision Adopting Demand Response Activities and Budgets for 2009 – 2011, A.08-06-011 et al., p. 124 , "PG&E and SCE state that aggregators are compensated to manage the customers they enrolled, and that utilities do not know how the aggregator compensate their individual customers."

[55] Infra note 36.

[56] California Independent System Operator, Demand Response Barriers Study (per FERC Order 719) April 28, 2009, Freeman, Sullivan & Co. Available at http://www.caiso.com/2410/2410ca792b070.pdf

the CPUC has implemented resource adequacy requirements to ensure the procurement of the sufficient capacity resources by regulated utilities.[57] The CPUC has also ruled that dispatchable demand response programs should count twords meeting resource adequacy requirements.[58] Demand response resources therefore have a value to the LSE to the extent they reduce the amount of capacity the LSE must purchase to meet RA requirements. But as previously noted there is no mechanism or market, at this time, that provides capacity revenues directly to the DR customer or aggregator. Aggregators therefore have chosen to work with utilities through contracts for demand response. But how have those contracts been received? What can aggregator behavior tell us about their independent operation, possibly unregulated activities should they take advantage of the option opened by the FERC to bid their demand response megawatts directly into the wholesale market circumventing the current state regulatory regime of contracted demand response megawatts?

Recently in *Decision Adopting Demand Response Activities and Budgets for 2009 through 2011*, D.09-08-027, Judge Jessica Hecht ruled on an issue involving aggregator contracts signed between SCE and several California Aggregators.[59] The Division of Ratepayer Advocates, a independent division within the CPUC charged with protecting ratepayers analyzed these contracts and their performance and argued that both the existing and proposed aggregator contracts with SCE are poorly structured and do not include ratepayer protections beyond similar contracts rejected by the Commission in March of 2003.[60] What alarmed the Commission is the assertion, successfully argued by DRA, is that "the payment and penalty history of the SCE contracts shows that in the months an event is not called, the aggregator is paid for capacity it has not shown it can deliver."[61] This meant that aggregators could and had been paid monthly capacity payment for a capacity product which they were not delivering. Taken further this meant that on the months that the aggregator was being paid for capacity, which it had not properly shown to possess, it was placing the contract and the utility in jeopardy of non-performance if the program was triggered to deliver energy to the contract holder SCE. DRA therefore successfully argued as noted by Judge Hecht that the contracts "have significant potential to overpay aggregators for demand reductions rarely if ever delivered."[62] This article argues that DRA was successful in their assertion of mal-performance on the part of the aggregators because a settlement agreement between DRA, SCE and the aggregators had been reached and successfully adopted by the Commission.[63] That settlement amended the SCE aggregator contracts to include provision that adjust capacity payments based on an aggregator's most recent performance in a Test, Re-Test or dispatch event to ensure that

[57] California Independent System Operator, Demand Response Barriers Study (per FERC Order 719), p. 30, April 28, 2009, Freeman, Sullivan & Co. Available at http://www.caiso.com/2410/2410ca792b070.pdf

[58] *Decision Adopting Demand Response Activities and Budgets for 2009 through 2011*, D.09-08-027, Issued 8/24/09

[59] *Decision Adopting Demand Response Activities and Budgets for 2009 through 2011*, D.09-08-027, Issued 8/24/09, p.143-146

[60] *Decision Adopting Demand Response Activities and Budgets for 2009 through 2011*, D.09-08-027, Issued 8/24/09, p.144, See also D.08-03-017 where the Commission rejected similar aggregator contracts

[61] *Decision Adopting Demand Response Activities and Budgets for 2009 through 2011*, D.09-08-027, Issued 8/24/09, p.144

[62] *Decision Adopting Demand Response Activities and Budgets for 2009 through 2011*, D.09-08-027, Issued 8/24/09, p.145

[63] *Decision Adopting Demand Response Activities and Budgets for 2009 through 2011*, D.09-08-027, Issued 8/24/09, p.145

payments during the ramp-up period and beyond are commensurate with actual performance.[64] [65]

A further example of demand response aggregator performance troubles was addressed, a year previous, by the FERC in 2008. In an Order entitles *Order Accepting Tariff Revisions, Subject to Conditions* the Commission approved PJM's tariff revision designed to address demand response gaming potential inherent in PJM Open Access Transmission Tariff and PJM's Operating Agreement.[66] In 2006 PJM became aware that entities were seeking compensation for load reduction as part of PJM's economic demand response program that would have happened regardless of the price or program dispatch signals from PJM.[67] PJM therefore concluded that its economic demand response program was, "susceptible to gaming."[68] PJM proposed various tariff modifications to address the issues presented in the filing. Modifications included changes in customer baseline load calculations, revising the definition of an event day, allowing participants to negotiate alternative baselines, creating a set of conduct codes that provides guidance as to which types of activity are not considered price responsive, establishing a review process for contesting or denying demand response registration and or settlements, establishing express aggregation rules and finally establishing flexible rules to enhance participation of self-scheduled and dispatchable demand response.[69]

EnergyConnect, Inc. (ECI) an aggregator active nationally, including in the California markets, protested PJM's filing. ECI argued, in part, that should PJM suspend ECI's ability to participate in their market for improper conduct, all of ECI's aggregate end-users, under contract to ECI, could be adversely affected.[70] Here we see an example of how the aggregator operates through exclusivity contracts with end-user customers and how those customers could be potentially harmed by potential malfeasance of the aggregator in a relationship between the aggregator and the end-user which is unregulated by the FERC and in most cases unregulated by the State.

Taken together these instances of aggregator behavior is worrisome. We see that in cases in California aggregators were unable to meet the capacity requirements in contracts with IOUs. In the East we see the specter of market gaming. These instances point to either highly sophisticated behavior to take advantage of a burgeoning industry or naivety of a wholly new industry. Either way the entities that aggregate end-user demand response are placing the end-user in a potentially disadvantageous position. The fact that the FERC is willing to open wholesale electricity markets to direct bid in demand response is a positive step forward. However most end-users are not in the business of selling curtailment nor are they familiar, or care to become familiar with wholesale market bid and settlement protocols. This creates a niche market for aggregators to operate. However, FERC's push to open markets to include demand response may have been short sided and premature, or a least lack proper due diligence to ensure that either the FERC or the States were prepared to protect the end-user from potential misconduct of an entity which offers a product similar to an energy service provider one which pays the

[64] *Decision Adopting Demand Response Activities and Budgets for 2009 through 2011*, D.09-08-027, Issued 8/24/09, p.145

[65] See also Attachment A to Proposed Decision of ALJ Hecht in Application A.08-06-001, Mailed 6-30-09.

[66] *Order Accepting Tariff Revisions, Subject to Conditions*, 123 FERC ¶ 61,257, Issued June 12, 2008.

[67] *Order Accepting Tariff Revisions, Subject to Conditions*, 123 FERC ¶ 61,257 at P. 2, Issued June 12, 2008.

[68] *Order Accepting Tariff Revisions, Subject to Conditions*, 123 FERC ¶ 61,257 at P. 2, Issued June 12, 2008.

[69] See *Order Accepting Tariff Revisions, Subject to Conditions*, 123 FERC ¶ 61,257, Issued June 12, 2008.

[70] *Order Accepting Tariff Revisions, Subject to Conditions*, 123 FERC ¶ 61,257 at P. 12, Issued June 12, 2008.

customer for modified energy use as opposed to charging the customer for consuming energy.

By 2012 California will be the first state to have deployed advanced meters to all end-users. These units will be capable of reporting 15 minute interval data, which is enough frequency for acceptance in most demand response programs across the country, whether the program is operated at the wholesale market level or the utility level. Residential demand response is an essentially untapped demand response resource yet with the proper technology such as AMI would be enabled to offer demand response. Aggregator business models are structured in such a way to take advantage of aggregating small residential loads and selling the demand response megawatts back to the wholesale market. The business model of most utilities is not set up in such a manner as to make wise business sense to resale purchased power back to the wholesale market. A move which could decrease utility revenue. Therefore as AMI and other smart grid assets are deployed throughout the country to end-users we can see a healthy market for aggregator participation. Alarm bells should be going off at various State regulatory bodies. Here we have the potential for an entity to enter into contracts with end-users who are probably not aware of how energy markets functions. These relationships are not overseen by any regulatory body. They are not within the jurisdiction of the FERC because these transactions are with the end-user and are therefore within the exclusive jurisdiction of the State. This author was not able to find one state which regulates or oversees, directly, the relationship between the end-user and demand response aggregators. The States needs to take primary regulation over Demand response. That is the primary transaction for demand response is at the retail level and States should be free to structure this demand response marketplace as they see fit. The FERC should be barred from attempting to open a parallel or complimentary marketplace within the State. The FERC's place with respect to DR is only at the wholesale market level and should be relegated to wholesale market structure and how that structure incorporates DR.

Although this author supports FERC's efforts to require RTOs and ISOs to amend their market rules to permit ARCs to bid demand response on behalf of retail customers directly into RTOs and ISOs organized markets, one should be cautious of the proposal's implementation.[71] California, for example, is a sizeable market, and currently demand response aggregators face an impediment to directly bid their demand response megawatts into the wholesale energy market because, as already mentioned in the preceding paragraphs, current CPUC policy is such that each meter may only be served by one Scheduling Coordinator.[72] Allowing ARCs to directly bid their demand response megawatts into the wholesale energy market could potentially create a separate and distinct energy market, outside State jurisdiction despite the interactions and impacts on retail customers. Current policies enable the CPUC to indirectly influence the business practices of ARCs through their contractual relationship with California IOUs. However, this author again cautions that opening a demand response market to ARCs may leave the retail customers unprotected and not adequately informed due to the current lack of a proper regulatory framework.

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[71] *Comments of the Public Utilities Commission of the State of California* to Docket Nos. RM07-19-000 and AD07-7-000, p. 16 (April 21, 2008).

[72] *Order Instituting Rulemaking on the Commission's Proposed Policies Governing Restructuring California's Electric Service Industry and Reforming Regulation; Order Instituting Investigation on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation*, Decision No. 97-10-087, Rulemaking No. 94-04-031 (Filed April 20, 1994), Investigation No. 94-04-032 (Filed April 20, 1994), 76 CPUC 2d 287 (Oct. 30, 1997).

CONCLUSION TO JURISDICTIONAL ARGUMENT

It is evident from previous FERC decisions that the Commission considers demand response to be within its jurisdiction. Coupled with FERC's directive to the CAISO to remove the one scheduling coordinator per meter rule in Tariff section 4.5.1.1, Commissioner Wellingoff's views in favor of FERC jurisdiction over demand response, come to a confluence in the recent FERC Final Rule in Order No. 719 to eliminate all barriers to direct bid in demand response. These events give reason to pause and ask- "does the FERC intend to open a demand response market? Is it one outside the State regulatory reach? If so, what does this mean for rate payers?" With lack of State jurisdiction, retail customers may be inadequately protected. Customers will be solicited by different, unknown, entities without fully knowing the intricacies of the services provided by ARCs and the value of such service. Traditionally, through the restructuring period, the States have had almost complete jurisdiction in regulating service provider's interactions with retail customers. If the FERC Rule to require RTOs and ISOs to amend their market rules as necessary to permit ARCs to bid demand response on behalf of retail customers directly into the market takes hold and does encourage a parallel federal DR marketplace the States will struggle to control a growing demand response market.

PART II

THE DEMAND RESPONSE MARKET STRUCTURAL PITFALLS OF FERC OPENING THE WHOLESALE MARKETS TO ARC BID DEMAND RESPONSE

Many will agree that the most efficient and elegant form of demand response is one driven by rate structures. Dynamic rate structures whether simple TOU, CPP or real-time rates encourage the customer to change their energy usage habits or patterns for the simple incentive of a lower electricity bill.[73] The push by Congress to investigate, report and collect information on dynamic rates and Advance Metering Infrastructure shows the direction Congress wishes to take demand response.[74] Dynamic rates structures, and the appropriate consumer response, release the LSE of the need to create demand response programs which require front office activities such as outreach, marketing and subscription; back office activities such as billing, measurement and verification and payment.[75] Programmatic, incentive based demand response requires, regulatory oversight, teams of people to create, manage and operate each different demand response program. The customer becomes used to receiving monies for performance, usually in lump sum payments. This article argues that FERC actions in Order 719 exacerbate the problems and inefficiencies created by programmatic driven demand response, encouraging programmatic type demand response to be bid into the wholesale market by aggregation of retail customers.

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[73] " A system including measurement devices and a communication network, public and/or private, that records customer consumption, and possibly other parameters, hourly or more frequently and that provides for daily or more frequently transmittal of measurements to a central collection point. AMI has the capacity to provide price information to customers that allows them to respond to dynamic or changes prices." *A National Assessment of Demand Response Potential*, Staff Report, Federal Energy Regulatory Commission, June 2009. Prepared by The Brattle Group, Freeman, Sullivan & Co., Global Energy Partners, LLC.

[74] See Energy Policy Act of 2005 Section 1252 Smart Metering. See also Energy Information and Security Act of 2007 Section 529.

[75] "The direct connection between wholesale prices and retail rates introduces price responsiveness into the retail market, and serves to provide important linkages between wholesale and retail markets. Assessment of Demand Response and Advanced Metering, Staff Report, Docket AD06-2-000 August 2006, p. 61

Although the FERC agrees that dynamic rates create, "the direct connection between wholesale prices and retail rates [which] introduces price responsiveness into the retail market," serving an important linkage between the two markets and the end-user, it seems that FERCs requirement that the ISO/RTOs to open their markets to aggregator bid-in DR is contrary to an effective rate driven demand response market structure. Curtailment Service Providers or as FERC identifies them as ARCs, do not have the authority to change retail rates. Therefore these entities sign bilateral contracts with end-users for event driven curtailments at a preset price. Some of these contracts pay a monthly reservation fee to the end-user, otherwise known as a capacity price. These contracts also pay the customer an additional incentive for performance or what is otherwise known as an energy price. This type of incentive structure offers the end-user lump sum payments for agreeing to sell curtailment options to the aggregator who in-turn sells the unused power at the wholesale market. The customer must be outfitted with telemetry and metering and communication protocols must be instantiated to ensure that the customer initiates the contracted curtailments. Measurement and verification of a curtailment is a complicated business. Baseline methodologies are as unique as the geography of any one State. It was these baseline methodologies that created the potential for gaming in PJM's demand response market in 2006.[76] In states like California where aggregators must work under contract to the investor owned utility to supply demand response complicated contracts between the aggregator and the IOU must be approved by the regulator, sometimes with mixed results.[77]

In her concurring and dissenting opinion in Order 719 Commissioner Kelly stated in dissent that requiring RTOs and ISOs to implement Scarcity Prices without ensuring that consumers be given the "ability to respond to higher prices," troubling.[78] This author too finds it troubling that FERC has encouraged a form of demand response, incentive driven demand response, without first encouraging a more elegant and efficient form of demand response, rate driven demand response capable of meeting not only scarcity pricing demand but market demand in general without taxing the consumer with additional programmatic costs.

COORDINATING PROGRAMMATIC DR, AGGREGATOR PARTICIPATION, BETWEEN THE WHOLESALE AND RETAIL MARKETS

The scheduling and coordinating efforts required to incorporate aggregator sponsored DR into the wholesale market is an inefficient mechanism to harness the benefits of demand response. While FERC's actions to incorporate aggregator demand response into the wholesale market is commendable, efforts should have been taken to ensure proper coordination between the wholesale and retail markets. Arguably the most efficient form of coordination is through a dynamic rate type mechanism. However such would require FERC, ISO/RTO, LSE and State Regulatory coordination on policy and implementation. FERC, regrettably, truncated any coordination with the issuance of Order 719.

Coordination efforts in California

[76] Order Accepting Tariff Revisions, Subject to Condition Docket No. ER08-824-000 123 FERC ¶ 61,257

[77] See Order Approving Four Southern California Edison Company Demand Response Contract, Decision 08-03-017, March 13, 2008 California Public Utilities Commission; See also [77] *Decision Adopting Demand Response Activities and Budgets for 2009 through 2011*, D.09-08-027, Issued 8/24/09, p.144, See also D.08-03-017 where the Commission rejected similar aggregator contracts

[78] FERC Order 719 Wholesale Competition in Regions with Organized Electric Markets, Docket No. RM7-19-000, AD07-7-00 Commissioner Kelly, concurring in part and dissenting in part.

With over 2500MW of curtailable load California represents one of the largest demand response market places in the country.[79] However recent regulatory filings show that coordination is lacking between aggregator sponsored demand response, LSEs, and wholesale markets. On July 9, 2008 the Alliance for Retail Energy Markets, a consortium of energy service providers, (AReM) filed a protest in application proceedings A.08-06-001, 002 and 003, California's proceeding to review IOU sponsored demand response programs, goals and budgets for 2009-2011. Energy service providers (ESP) in California serve direct access customers. These customers, are not part of the IOU regulated customer base and are therefore not eligible for most of the demand response programs offered by the IOUs. However direct access customers are eligible for enrollment in aggregator sponsored programs. AReM's protest in part stated that such programs "hamper electric service provider operations."[80] Specifically AReM noted that it had found, utility contracts with third-party aggregators and end-use customer (where applicable) for DR programs fail to specify notice to the ESPs. While other such agreements do require notice to ESPs, there are no specifics about the timeliness or the form that the notice should take. More significantly, none of these agreements contained any provisions to enforce the notice requirements. The ESP contractual relationship is with its customer; it has no contractual relationship with a third party-aggregator or with the utility for DR purposes.[81]

Essentially what AReM is stating is that aggregators in California were signing contracts with direct access customers without notification to the ESP. Once a curtailment was called the ESP was notified to make a transfer of energy to the IOU on a moments notice.

When the DR program coordinator (the aggregator) notifies the ESP that the SC-to-SC transfer is required, this is often the first time that the ESP becomes aware that its customer has enrolled in the program and is expected to curtail load the next day or the next hour….this just-in-the-nick-of-time notification to the ESP is not in the best interests of the customer, who may have pre-existing contractual arrangements to address with the ESP, nor will it facilitate the smooth and effective operation of the dispatchable DR programs themselves. [82]

In PJM we see a different regime for aggregator participation in the market. The system amounts to a complex system of coordination and notification.

COORDINATION IN PJM

PJM treats curtailment service providers (aggregators) as "special members" of PJM that participate in the Interchange Energy Market. Curtailment service providers (CSP) are treated as special members because of the resource they provide, demand response.[83] This special members status, and the way afforded to CSPs is unique within PJM principally because the resource type offered which thereby implies that demand response is treated differently from generation within PJM. Regardless of this

[79] *Assessment of Demand Response and Advanced Metering 2007*, Federal Energy Regulatory Commission, Staff Report, September 2007, p. B-6. See also The California Energy Commission's forecast of the three utilities peak demands can be found at http://www.energy.ca.gov/2007publications/CEC-200-2007-015/CEC-200-207-015-SF2.pdf

[80] *Protest of Alliance for Retail Energy Markets*, before the California Public Utilities Commission, A.08-06-001,002, and 003 filed on July 9, 2008.

[81] *Protest of Alliance for Retail Energy Markets*, before the California Public Utilities Commission, A.08-06-001,002, and 003 filed on July 9, 2008 at p. 6

[82] *Protest of Alliance for Retail Energy Markets*, before the California Public Utilities Commission, A.08-06-001,002, and 003 filed on July 9, 2008 at p. 7

[83] PJM Manual 11: Scheduling Operations, Revision: 43 Effective Date September 24, 2009, Prepared by Forward Market Operations, p. 104.

argument we can see how complex a system of coordination and notification PJM has structured for demand response resources and their representative CSPs.

For a resource to be registered through a CSP to PJM for supply of demand response the CSP must, in part, supply the following: customer energy supplier, electric distribution company, pricing zone, PNODE, dispatch contact information (if willing to be dispatched by PJM), retail rate, metering requirements and if the reduction under a load management contract prior to 6/1/2002.[84] To collected information for settlement and baseline establishment the CSP must submit to the customer and the LSE a customer usage information authorization for PJM load response programs.[85] Upon submittal of the information PJM will review the proposed baseline methodology, confirm with the appropriate load serving entity, electric distribution company whether the load reduction is under other contractual obligations, confirm with the customer's LSE whether the demand response is served under day-ahead or real-time LMP based contract for energy delivery, verify the transmission and generation (retail rate) charges with the appropriate EDC and LSE, and verify whether or not the resource is subject to a load management contract.[86] After all this, notification that the resource has been accepted by PJM as a demand response resource is the responsibility of the CSP or the customer.[87]

For a demand resource to receive a settlement from PJM for performance several forms of information must be submitted post performance. Metering data must be submitted to PJM within 60 days of the reduction.[88] PJM will check to see that notification and settlement hours match. If the settlement hours do not match, then PJM will review the CSP's settlements for up to the 12 month prior to determine if free-ridership is present.[89] Metering data must be supplied for the hour before, hour-of and hour after the curtailment. This metering data is then forwarded to the EDC and the LSE who then have 10 days to provide feedback.[90] All this coordination and information still does not touch on the complexities of calculating the customer baseline. Which while relevant to this discussion is so complex that a separate issue paper could be written on the topic as baseline calculations are still a moving target among the various entities charged with measurement and verification of demand response resource performance.

The coordination, notification and communication complications and extensive efforts needed to incorporate ARC bid demand response into the wholesale markets leads one to ask why would FERC pursue further establishing such a structure when AMI and the capability of retail customers to respond dynamic rates is close at hand? This author commends FERC and its actions to incorporate demand response into the wholesale markets. This action has placed emphasis on demand response as a viable market resource and has highlighted its capabilities. However this article argues, in part, that the unilateral move by the FERC to open the markets to ARC bids will

[84] PJM Manual 11: Scheduling Operations, Revision: 43 Effective Date September 24, 2009, Prepared by Forward Market Operations, p. 106-108.
[85] PJM Manual 11: Scheduling Operations, Revision: 43 Effective Date September 24, 2009, Prepared by Forward Market Operations, p. 109
[86] PJM Manual 11: Scheduling Operations, Revision: 43 Effective Date September 24, 2009, Prepared by Forward Market Operations, p. 112-113
[87] PJM Manual 11: Scheduling Operations, Revision: 43 Effective Date September 24, 2009, Prepared by Forward Market Operations, p. 113
[88] PJM Manual 11: Scheduling Operations, Revision: 43 Effective Date September 24, 2009, Prepared by Forward Market Operations, p. 117
[89] PJM Manual 11: Scheduling Operations, Revision: 43 Effective Date September 24, 2009, Prepared by Forward Market Operations, p. 117
[90] PJM Manual 11: Scheduling Operations, Revision: 43 Effective Date September 24, 2009, Prepared by Forward Market Operations, p. 118

only breed complications in bid, settlement, notification and most importantly regulation. The FERC recently added a state relations division led in part by former Vermont Public Service Board staff member Sandy Wienstein. This is an excellent move by the FERC, as FERC should be working with the State commission's to find the best way to incorporate demand response resources, which are primarily retail resources (retail customers). Coordination between the States and the wholesale markets is the best and most viable long term strategy for a solid structure which allows demand response to impact wholesale market prices.

A PLATFORM FOR EFFICIENCY AND ELEGANT PARTICIPATION OF DEMAND RESPONSE AS A MARKET RESOURCE

The problem with incentives

Currently most demand response is cultivated through a process whereby the end-user agrees to curtail usage in exchange for a monetary incentive either as an energy payment, or a capacity payment or both. These payments can be quite lucrative, paying many large users tens of thousands of dollars per year. With few exceptions most demand response programs work this way. Niagra Mohawk, Southern Company and those States which have instituted some form of CPP or VPP such as California are generally the only programmatic exception to incentive driven demand response.

FERC Order 719 perpetuates the incentive mechanism for achieving demand response megawatts. No aggregator operates a rate based demand response program. These entities because they do not serve energy to consumers cannot charge or change the rates of those taking service from the LSE. Therefore aggregators operate on an incentive platform. These programs usually call the end-user for curtailment for a set number of times out of the year, at a set incentive price per kilowatt, for a set time period usually 2-6 hours. Most customers of aggregators are commercial and industrial facilities. The incentive monies received from the aggregator can be in the several tens of thousand of dollars. The customer becomes used to these large lump some payments for participation in programs. The regulatory body that then wants to change demand response platforms away from incentive based payments must then justify or explain to these, often politically powerful companies, how dynamic rate based demand response is a more efficient form of demand response.

An example of the political pressure that a regulatory body may experience can be seen, again in California. In Rulemaking R.07-01-041 Phase III Judge Sullivan is attempting to adjudicate moving some of California's 2000 MW of emergency demand response to a CAISO price or bid based trigger as opposed to a CAISO reliability trigger. CECLA, a consortium of large commercial and industrial end-users has argued, (despite the fact that the emergency resources have only been called on 10 times since 2002 (not at all in 2003 or 2007)) that the majority of California demand response megawatts should not be moved to a more frequent trigger because California would risk losing subscription to its demand response programs, particularly its emergency demand response programs. Rather then play chicken with this powerful group of end users the CPUC is looking into moving 900 MW of SCE's, AC cycling program (made mostly of small commercial and residential customers) to a non-emergency trigger.

Rates, dynamic pricing is the most efficient form of demand response

Dynamic pricing, whether, CPP, TOU or Real-time rates are a more efficient mechanism to harvest demand response megawatts rather than programmatic, incentive mechanisms. There is no bidding and settlement, no complicated baseline

measurements, less utility staff needed and overall fewer monies expended to receive an end-user response to market and grid conditions.

FERC's Order 719 is an extraordinary leap forward for demand response. Recognizing the merits of demand response as a market assets is the most important aspect of the ruling. Requiring that wholesale markets incorporate, open their markets to demand response resources, is also an extremely important step for demand response and the market in general. However FERC's unilateral movement to open a demand response marketplace was perhaps too exclusive. Had the FERC worked closely with the States, perhaps the more progressive, may have found ways to work with the FERC on a plan to move toward dynamic pricing tied to wholesale market prices that would encourage demand response that meets the needs of all parties.

In her dissent and concurrence of Order 719 Commissioner Kelley, stated that the Order requiring the ISOs and RTO to institute scarcity pricing before end-users where properly enabled to response to such event was not an agreeable action. Scarcity pricing events happen when all capacity has been dispatched yet demand exceeds generation. During such events the market price cap is lifted in an attempt to entice additional resource participation. Logically the one resource that could and would respond to such events is demand. However, scarcity pricing events are generally short in duration yet may happen several times at day. What Commissioner Kelley was alluding to is that if the end-user was enabled in such a manner to know and respond to such events they most likely would, but AMI (the main enabler) is yet ubiquitous throughout the States and therefore most end-users are blind to scarcity pricing events. Such events will ultimately affect rates but not until the next rate case. FERC's push to institute scarcity pricing again would have been best accompanied with an out-reach campaign to the States to work on various methodologies and regimes to institute such a mechanism as scarcity pricing while protecting and enabling end-users to contribute to mitigation. Again one of the best ways to do this would have been through State, Federal workshops on dynamic rate structures.
The current programmatic model for demand response means that only resources large enough with a great deal of technical sophistication can bid or be aggregated and bid into the market during scarcity pricing events. Relying on these larger entities and their aggregator representatives is an inefficient mechanism to mitigate scarcity pricing events. It is also an inefficient model to harness demand response. California's default CPP rate for large customers is an excellent first step to tie wholesale events such as scarcity pricing with retail.

Transactive control

FERC's Order 888 and 2001 establishing the wholesale markets were ground breaking decisions. Over the years these markets have created an effective pricing model known as nodal pricing or locational marginal price (LMP). The LMP incorporates, generation availability, transmission availability, demand, congestion and constraints as they relate to proximate location of withdrawal and injection of energy.

Taken a step further and combined with dynamic rate structures the nodal model, if extended through the distribution grid, provides what could be the most elegant and most efficient grid operations mechanism we have yet seen. In 2006, in a project known as the GridWise Demonstration Project, DOE, PNNL IBM and BPA demonstrated just such a model, named transactive control.

The experiment demonstrated a nodal hierarchical system whereby grid needs and objectives where incorporated into a five minute pricing signal which was adjusted at each downward node.

Each downward node incorporated local conditions, demand and availability into the pricing signal. Such nodes could be extended all the way into the home. A node at the sub-transmission point of delivery, could be affected by the various distribution substations, the bus bars, the feeders, and the distribution transformers all of which could as hierarchical nodes affect the transactive pricing signal. What this also meant is that control of the system became distributed, as opposed to centralized at the utility. Each node need only send back up the hierarchy necessary aggregated information. This means that operators would see only the needed aggregated asset information not thousands or millions of singular points of end-user or demand side asset information which would then have to be optimized at the grid operators level, whether distribution or transmission grid level. Such a nodal hierarchical system can incorporate all aspects of the grid from bulk generation to single end-user usage and availability patterns.

The transactive control mechanism piloted in the GridWise Demonstration project was so successful that operators of the experiment were able to exactly match demand and supply for long periods of time. They were able, during highly demanding seasonal periods, to lower demand by nearly 50% for several days and extract a high level participation from end-user without their inconvenience.

Had FERC been working with the States on how to incorporate demand response into the market as opposed to working unilaterally to create a separate paralleled demand response market it is possible that we could have seen the extension of the nodal mechanism utilized by the bulk grid and ISO/RTO operators into the distribution grid. This nodal system would have operated on a dynamic rate like structure instead of a perpetuation of the programmatic incentive driven demand response offered to the market by unregulated entities.

FERC Order 719A and NAESB Priority Action Plans 3, 4, and 9

In Order 719A the FERC announced that it will adopt smart grid standards set by a process led by NIST. NIST requested NAESB to work on demand response standards for the smart grid implementation standards. NAESB has created three priority action plans 3, 4 and 9 all attempt to standards commonality among demand response within both retail and wholesale markets so that integration into the wholesale markets can be seamless or interoperable.

The work by NAESB on these standards is a positive step in the right direction, collaboration among stakeholders. Standardizing the communication, pricing and signaling information needed to integrate demand response programs whether retail or wholesale will go a long way to interoperability and commonality. Opening to process to stakeholders is a favorable approach which State regulators should be paying close attention to.

CONCLUSION

Overall FERC Order 719 was excellent policy giving demand response the support it needed to be properly regarded as a market asset. However what FERC has done is inadvertently opened a parallel demand response marketplace whose primary contributors are unregulated entities which must interface with the States end-users. Coordination between the FERC and the States could have opened a demand response market place that could have been more efficient with greater protection for the end-user.