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## **Barriers to Demand Response**

*Additional submitted attachment is included below.*

# **Joint Demand Response Parties' Comments on California Energy Commission's Workshop on Barriers to Demand Response (August 8, 2017) in Docket # 17-IEPR-12**

**August 22, 2017**

The Joint DR Parties include CPower Energy Markets, Inc., EnerNOC, Inc., and Energy Hub, Inc. These parties are actively engaged in providing demand response services in California. Please consider these comments in addressing barriers to demand response in the 2017 Integrated Energy Policy Report.

## **INTRODUCTION: HISTORY OF DR IN CA**

California (CA) has had demand response (DR) programs going back to the 1970's in the form of interruptible programs. During the energy crisis, it was determined that those programs were not as dispatchable as desired and may have been more akin to economic development programs. Since the energy crisis, DR programs have continue to grow and expand in terms of options available to customers. Many of these programs required only voluntary performance, without consequence. The CPUC in 2007, encouraged the use of 3<sup>rd</sup> party aggregators to, hopefully, increase participation and innovation. The innovation occurred in terms of software and hardware to enable better monitoring, measurement and control of customer consumption, including use of near, real-time data, wireless communication and control, data sharing with customers, sophisticated analysis of data consumption, automated DR, etc.

DR developed through IOU-administered programs, but included solicitation of 3<sup>rd</sup> party services. These programs grew until about 2011/2012. At that point in time, program parameters began to change frequently, penalties were tough, only one baseline was available to measure performance and it was unclear the direction that future DR programs would take, except that there was a strong desire to integrate DR into the wholesale market.

DR programs participation in terms of capacity has declined over the last 5 years (2011-2016). (See EnerNOC Presentation, page 1.) In particular, participation in the IOUs' programs by 3<sup>rd</sup> party aggregators have gone down. The only program in which participation has increased is the Base Interruptible Program (BIP) in both SCE's and PG&E's service territories. DR program participation decreased in PG&E's service territory by 212 MW or 30%. If the amount of BIP increase is excluded from the calculation, all other programs decreased in participation by 314 MW or 63%. For SCE, program participation dropped between 2011 and 2016 by 96 MW or 6.5%. However, if BIP increases in capacity over this time is excluded from the calculation, program capacity in all other programs dropped by 226 MW, or 25%. The loss of capacity is occurring in both residential and commercial/industrial sectors, despite the fact that Lawrence Berkeley National Laboratories (LBNL), in its DR potential study, identified significant amount of cost effective demand response available across these categories. (See LBNL Presentation, at p. 31)

Not only has the participation levels dropped, but 3<sup>rd</sup> parties have experienced a great deal of churn in terms of participating customers has also occurred. If customers stop participating in

DR Programs, other customers must be recruited to replace them. Customer churn means that 3<sup>rd</sup> parties must be continuously marketing to customers to participate in DR programs to meet capacity obligations. Marketing is a significant cost of customer recruitment.

## **Integration of Demand Response Resources into the California Independent System Operator's (CAISO) Market**

Discussion around integration of DR resources began with the passage of two FERC Orders, 719 and 745. FERC Order 719 determined that DR resources should be able to participate in wholesale markets on a comparable basis as generation, including compensation. However, when the ISOs/RTOs submitted their compliance filings, it was clear there was not a consistent vision as to what comparable compensation meant. As a result, FERC investigated comparable compensation and issued Order 745, which determined that comparability means that, to the extent DR is providing a net benefit, it will be paid the locational marginal price (LMP), the costs of which would be allocated to all beneficiaries.

FERC Order 745 was challenged to the 9<sup>th</sup> Circuit Appellate Court and then to the Supreme Court. During this time, there was uncertainty as to the validity of wholesale market integration of DR resources, including the efforts that had been underway at both the CPUC and the CAISO. It wasn't until January 2016 when the Supreme Court issued its Ruling, upholding FERC Order 745 in its entirety, that this uncertainty was resolved. This timing was significant because the DRAM pilot began on June 1, 2016.

### **California Public Utilities Commission (CPUC) Processes Relative to DR**

During the period of 2012-2016, there was an intense amount of work that needed to be done in order for DR to be integrated into the wholesale market. This included the development of Rule 24, which describes the relationship between IOUs and DRPs in terms of obligations to each other to facilitate customer participation in the wholesale market as well as sets the rules on how data to support for these customer transactions will be handled. These rules took several years to complete. In addition, the DR Auction Mechanism (DRAM) was developed. The contracts for DRAM needed to be negotiated in a stakeholder process. This was a timely and intensive process. There were several working groups to address a DR Potential Study, load modifying resources, supply-side resources, telemetry, etc.

While Rule 24 provides clarity as to the obligations of IOUs and DRPs to each other, there are several layers of regulatory oversight by the CPUC and the CAISO in order to effectuate DR participation in the wholesale market.

## **BARRIERS TO DEMAND RESPONSE GROWTH**

### **A. Lack of Clarity Around Vision of DR**

There are many different and, sometimes, competing visions of DR. The vision has changed over time. In some ways, by embracing future visions for DR, there is a corresponding discounting of the current value that DR provides. DR has historically been used for peak shaving and emergency response purposes. This is still the primary use of DR in most

markets. However, there is nothing wrong with providing a range of DR services, that include emergency response and peak shaving, but include other forms of DR to help with renewable integration as well.

Some of the descriptors used to describe “future” DR services include frequent availability, frequent dispatch, and short advance notification. Since current forms of DR may not meet all of those characteristics, there is narrative around current forms of DR “not providing the right kind of value to the grid”. That narrative de-values existing forms of DR unnecessarily. In addition, there is no discussion around how to provide the “right” incentives and value to customers to participate in, and/or to 3<sup>rd</sup> party DR providers to develop the “future” types of resources. Even the LBNL Potential Study agrees that there would be a need for significant policy development in order to achieve the DR value identified in its report.

### **B. Local Dispatchability.**

Local dispatch for resource adequacy (RA) has changed from the local capacity area (LCA) basis to the sub-LAP basis, for integration purposes, even though resource adequacy is determined on a LCA basis.

Other wholesale markets give DR resources the ability to deliver services across the system and then by a local delivery area. In CAISO, DR resources can only provide delivery on a sub-LAP basis, even if there is no price separation or constraint across a larger geographic area and even though local RA is determined on a LCA, not a sub-LAP basis. Further and further disaggregation of resources reduces the value of the resource and increases the risk of non-performance. It also increases the cost of managing many small aggregation, as opposed to one larger aggregation.

CAISO should allow DR resources to be dispatchable over a larger geographic area, unless needed for local reliability purposes. Generators are able to substitute capacity within an LCA if a unit goes down, for example. That flexibility of replacing capacity within an LCA is not available to DR.

### **C. Short Advance Notification.**

There was an emphasis on real-time availability with a short notification window for retail programs. Retail programs would be more valuable if they were capable of dispatch with 30 minutes notification, instead of day-ahead (DA) dispatches. Short notification windows for DR dispatch requires more coordination with customers, including the potential for automation. Shorter dispatch windows reduce the pool of eligible customers who can participate in a demand response program due to operations that could be compromised at the customer premise.

Yet, CAISO cannot modify its real-time (RT) commitments in order to take into consideration RT dispatches of DR. Therefore, in order to influence CAISO’s dispatch of resources, and to displace fossil-fuel generators, only Day-ahead (DA) DR resources, associated with retail programs, or load-modifying resources (LMRs), were deemed to have value to CAISO. To balance the potential value with the operational reality, the CAISO

really needs several hours ahead of running its RT market – one that would allow DR to be dispatched while there is still time to reconfigure the generation fleet. So, 3<sup>rd</sup> parties implemented the ability to respond within a short notification period, which is more costly to provide, for no additional value to the grid, from the grid operator. This inability to coordinate the dispatch of retail DR products with wholesale market operations was a catalyst to integrating DR resources into the wholesale market.

Now that almost all of the event-based DR is integrated into the wholesale market, the issue of coordination of retail programs with CAISO operations is moot. However, this is an illustration of some of the gymnastics to which DR resources were exposed without a good understanding of value to the CAISO.

#### **D. DR Resource Are Not Counted as Local Capacity Resources.**

Even when retail DR (LMRs) resources are dispatchable on a sub-LAP basis within 30 minutes, those resources are not counted toward the local capacity requirement (LCR) for transmission and long-term procurement planning purposes, because CAISO states that it needs resources that are either frequently available or have short-notification requirements, of 20 minutes or less, to meet NERC contingency requirements.

#### **E. Dispatch Frequency.**

In some instances, dispatch frequency increased by a factor of 2, year-over-year, without warning, in order to demonstrate value and to assuage concerns about the value of the resource. This lack of coordination regarding program expectations among IOUs, 3<sup>rd</sup> Party Aggregators and customers resulted in customer dissatisfaction with programs and customer attrition.

#### **F. SONGS.**

When San Onofre Nuclear Generating Station (SONGS) went down, DR providers had commitments related to other retail programs. These programs were not developed with the geographic specificity of replacing SONGS and were not developed to meet the dispatch criterion of an LCR, as described above. Rather than jeopardize meeting the requirements of existing commitments to chase a short-term SONGS need, many 3<sup>rd</sup> party DRPs elected to continue meeting existing obligations under existing contract and program requirements. Yet, the inability to solicit a significant number of DR resources during the outage is identified as a failure of the resource.

#### **G. Loss of RA Value for LMRs.**

The CPUC determined in D.15-11-042 that all event-based programs that were not integrated into the wholesale market as a supply-side resource would be ineligible for RA treatment as an LMR. The only programs that are now considered legitimate LMRs is DR related to time-of-use (TOU) rates, critical peak pricing (CPP) or peak-day pricing (PDP) programs. This resulted in the termination of the Aggregator Managed Portfolio (AMP) contracts in 2016 for PG&E and 2017 for SCE. AMP contracts were a significant portion of 3<sup>rd</sup> party aggregator

MWs. These contracts were terminated, even though wholesale market integration, through the DR Auction Mechanism (DRAM), was still in a pilot stage. There are still about 145 MW of SCE's DR capacity that cannot be integrated into the wholesale market and may just be lost because of this rule.

#### **H. Lack of a Procurement Target.**

Unlike with other preferred resource types, DR has suffered from having a "soft" target over the years, which has resulted in DR capacity remaining relatively flat, or declining, in terms of growth over time. RPS has a specific state-wide, future target. Storage has a specific target to be met over a specific timeline. The DR target, going back to 2003, is 5% of system peak. And, that number has been hit, depending upon how DR is defined. DR is co-equal to EE at the top of the loading order, yet there is little in place to encourage DR procurement over other resource types. In fact, there may be factors in place that discourage DR procurement.

In the current DR Rulemaking (R.13-09-011), establishing a DR target is part of the scope of the proceeding. However, no DR procurement target, other than a requirement for IOUs to procure up to 1 GW of DRAM, once DRAM becomes a permanent program, before an IOU can seek relief, was established in D.15-11-042.

#### **I. Cost Effectiveness.**

DR is required, by statute, to be cost-effective relative to other resources. Storage, at present, is not required to be cost effective. Renewables are required to meet a market price referent. But, what value is being ascribed to DR? Mostly, it is the avoided capacity costs in the summer months for the top 100 hours. This means that if you want DR in the winter months, there is no avoided capacity value for DR in those months. Capacity value is the primary source of value for DR, as an infrequently dispatched resource. Without an avoided capacity value, there is no basis for providing a capacity payment to DR resources and still pass a cost effectiveness test, outside of June, July and August. There is no value associated with frequent dispatch. There is a slight increase in value for a short notification trigger. So, all of the things that are stated as future values for DR, increased availability, frequent dispatch and short notification times, are not reflected as significant values in the cost effectiveness methodology. Even DR resources that can be dispatched with increased geographic specificity is modestly recognized as a value for DR in the cost effectiveness methodology.

#### **J. Lack of integration of DR resources into long-term planning (LTPP, TPP).**

As mentioned above, despite DR meeting RA requirements, including being dispatchable on a locationally-specific basis by sub-LAP, being dispatchable with 30-minutes notification, several hundred MWs of DR were not included as either a supply- or load-modifying resource for purposes of determining resource needs for transmission planning purposes or for long-term procurement planning purposes. This was a significant devaluation of DR that was developed by the IOUs through their retail programs, as directed by the CPUC. By not

recognizing the capacity associated with these programs for long-term planning purposes, other resources had to be procured to meet the net short position. By purchasing additional resources and not counting DR resources toward the net-short position, ratepayers were not receiving the full value from these programs. This created a perception that DR resources were less valuable.

It is important that DR resources are accounted for as supply resources, if they are integrated into the wholesale market, and as LMRs in the demand forecast, as TOU or CPP/PDP resources.

#### **K. Limited Growth Opportunities for DR and Declining Enrollments.**

1. Eliminated programs - as mentioned above, the AMP Contracts are no longer available for 3<sup>rd</sup> party aggregators as of December 2016 in PG&E's service territory and December 2017 in SCE's service territory. Demand Bidding Program (DBP) is also being terminated because it cannot be integrated into the wholesale market. With the elimination of these programs, including several hundred MW of 3<sup>rd</sup> party aggregator capacity, there were limited opportunities to place that capacity in other programs. Namely, customers could either participate in the DRAM pilot, in BIP or in the Capacity Bidding Program (CBP). CBP is the most frequently dispatched DR program with the lowest available capacity payment relative to AMP and BIP. As such, this is an unattractive option for customers.
2. Capped programs - BIP is the most attractive DR program for customers to participate in because it receives a sizeable capacity credit, pursuant to the tariff, and infrequent dispatches. However, BIP customers have greater availability requirements and are subject to significant energy penalties for failure to meet the capacity commitment, when dispatched. This program is capped at 2% of the overall maximum system peak for 2016, approximately 50,000 MW, making the cap for reliability-based programs approximately, 1,000 MW statewide. SCE has approximately 700 MW and PG&E has approximately 300 MW, with SDG&E at about 20, MW. BIP is nearly, if not fully, subscribed at this time; therefore, displaced capacity from pre-existing AMP contracts cannot move into this tariff.
3. Limited budget for new programs - because DRAM is a pilot, the budgets have been limited over the last 3 procurements for all 3 IOUs: \$6 million in 2016; \$13.5 million in 2017; and \$27 million for 2018 and 2019, making the average procurement per year flat over the 2017-2019 period. Low and flat funding for DRAM, which, in D.15-11-042, is the primary means for procuring DR in the future, is not picking up the slack for closed or capped programs. This transition results in stranded capacity that has no place to go, but away.



#### **L. Inconsistencies between CPUC and CAISO RA Rules.**

After each DRAM pilot was launched, and parties were waiting for the IOUs to make their resource selections, there was market uncertainty introduced relative to the RA rules that would be applied to those resources. DR resources are required to bid into the CAISO's DA and/or RT markets during certain hours of the day, on non-holiday weekdays, to receive RA credit. During these periods, CAISO submitted a Business Practice Manual (BPM) change to revise the hours in which DR resources would bid into the wholesale market, known as the RA Availability Assessment Hours (AAH). This change was not coordinated with the CPUC's RA Proceeding. Since the proposed BPM change was made public around the time with DRAM bids were being submitted and the IOUs were making their selections, if the rules had changed, it could have been devastating to the pilot and the bidders ability to meet its commitments. This could have resulted in the 3<sup>rd</sup> party DR Provider (DRP) having to significantly reduce its bid, potentially to zero, or refuse to accept the offer.

In 2016, CAISO introduced a resource requirement change, through a BPM process, in order for resources to meet local capacity requirements. These resources would have had to either demonstrate adequate availability for frequent dispatch or be available for dispatch with 20-minutes notification. Again, these resource requirements were not coordinated with the CPUC, creating a schism between the two agencies over RA requirements.

This kind of agency fracturing over significant energy policy, which would have disproportionately negative effects to DR resources, is very concerning and harmful.

#### **M. Inconsistent Valuation of Services Relative To Customer Burden.**

As described above, there are many inconsistencies in terms of what is stated as desirable from a policy perspective and what is valued in a cost effectiveness methodology, the latter of which determines the maximum payments that customers can receive for providing services. If greater availability, frequent dispatch and short notification times are valued and reflect where DR resource development is being guided for the future, then cost effectiveness must adapt accordingly. If customers do not receive greater value for providing more costly and disruptive services, they won't provide them.

#### **N. Regulatory Burden.**

The amount of time and effort that has been devoted to determining the future direction of DR in the state, while perhaps necessary, has been extremely costly in terms of time and labor intensity. This is a barrier to entry for new market participants who cannot afford the significant regulatory resources to adequately participate in the many venues where DR issues are at stake: CPUC, CEC, CAISO and the legislature. Even those agencies with some resources expend a significant amount of capital and, as described above, only experience declining sales.

## **O. Frequent Changes in Program Rules and Requirements.**

When program changes occur on a year-to-year basis, program participants must make systems and contract modifications, both with the IOUs and with customers, in order to effect those changes. Contract changes are time intensive and expensive, in order to get all existing customers to agree to changed terms. When there is inadequate time to implement those changes, capacity levels can decline. The implementation costs of these changes are not always given adequate consideration.

## **P. High Penalties.**

When customer performance is not properly measured, as described more fully below, customers, under retail programs like BIP and CBP, and previously AMP, could be exposed to high penalty levels. That means, even if a customer has done its best to perform, and has performed, the baseline methodology may not record its accurate performance. And, because the performance is not accurately recorded, the performance level may trigger penalties that could eliminate half or more of the revenue that the customer or aggregator would have received. It is not hard to understand how customers, and aggregators, would be deterred from continuing to participate in a program that neither recognized nor paid for performance provided to the grid.

## **Q. Lack of Measurement Options.**

Only one baseline measurement option was available for DR, which is a 10-in-10 baseline, with an option day-of adjustment of between 20 or 40%, depending upon whether the resource was included in the wholesale market or participating in a utility program. This failed to take into consideration significant temperature sensitivity, especially for air conditioning load. The CAISO Board of Governors has just approved new baseline methodologies for DR participation in the wholesale market. CAISO will file to FERC for approval of these baselines. Once approved, these options should also be offered in utility DR programs. Accurate measurement of customer performance is paramount to continued customer participation.

## **R. Lack of Customer Awareness.**

President Picker has said that DR has a public relations problem because a customer can't see anything shiny or physical, like a PV panels or a storage facility; yet, it provides value to the grid. If DR is to grow, increasing customer awareness is important. Third parties and IOUs should be partners in increasing customer awareness and encouraging customer participation, including with 3<sup>rd</sup> party providers. The most expensive part of any 3<sup>rd</sup> party DR aggregators program is marketing and sales, in trying to recruit and educate customers. A partnership with the utilities in developing customer awareness and driving customer adoption would be very helpful.

## **S. Comparability of Customer Access to Utility Services as Between IOUs And 3<sup>rd</sup> Party Aggregators.**

Now that IOUs and 3<sup>rd</sup> party DRPs are going to co-exist in providing DR services, it is important that there is comparability to access to utility services as between IOU and 3<sup>rd</sup> party services. Otherwise, the IOU's services can appear to be at a premium to a 3<sup>rd</sup> party's services. This could include enhanced or faster access to information, access to incentives, or access to programs.

#### **T. Access to Customer Data.**

Customer data provides the backbone upon which M&V is done for any DR program. In a digital world, customer expect to grant access to third parties in a seamless, click through process, the way they accept mortgage terms, open bank accounts and apply for credit cards. Today, this is not the case for sharing their usage and account data. Customers must sign a paper CISR form and send it to their aggregator, who then sends it to the IOU for processing.

The IOUs are working on the usage of Green Button Connect to allow customers to give permission to the IOU to share data with a 3<sup>rd</sup> party, however this process if not designed correctly will have a dire impact on 3<sup>rd</sup> party aggregators, especially those with mass market customers. Mass market aggregators prefer to design their own pathway for customers to enroll in 3<sup>rd</sup> party programs, that do not rely on IOU web design capabilities or copy writing. This will continue to be an obstacle to achieving the 1 GW target, unless and until, 3<sup>rd</sup> parties are enabled to use popular 2017 digital tools to authenticate their customers and have customers authorize their data to be shared.

### **WHERE SHOULD WE FOCUS OUR EFFORTS NEAR TERM?**

#### **A. Data Access.**

In order to have a customer participate in the wholesale market, DRPs need timely access to customer data – for assessing a customer's fitness for enrollment in a DR program, to complete a CAISO/utility registration and on an ongoing basis to assess customer performance and perform the settlements required with the markets. Currently, efforts are underway to provide data for DR customers and their providers under Rule 24 to allow Click-Through Processing of customer authorizations to provide data access to third parties. This will be a significant improvement over current methods. There are still future improvements that need to occur. Failure to have timely access to data puts third party providers at a distinct disadvantage in all phases of the customer lifecycle from customer enrollment, to program participation to settlements and payments. Lack of near real time access to data is causing customer dissatisfaction that can keep customers from enrolling in programs – and from performing once enrolled.

#### **B. Grow DRAM.**

The CPUC has indicated that it wants DRAM to be the avenue for third party procured DR into the future. As noted above, DRAM procurements have not kept pace with ending programs. Supply side DR must be planned for across all planning processes – Long-Term Procurement Proceeding (LTPP), Distribution Resources Proceeding (DRP), Transmission Planning Process (TPP), Integrated Distributed Energy Resource Proceeding (IDER) and

within the IEPR which contains assumptions supporting all of the other planning processes. This will ensure that resources are appropriately accounted for in determining new resource needs. The state needs to expand DRAM procurements – and not foreclose on other options for third parties and our DR customers to participate in until robust and growing markets like DRAM are in place.

**C. Adopt new baseline options in retail programs.** The single baseline available today has undervalued participation from DR customers. You can watch a customer meter when events are called and curtailment plans are triggered to see the customer shed load – but judging all customers across a 10-day prior usage profile does not work for many customers – and as a result their load shed is devalued. The CAISO has recently adopted (pending FERC approval) several new baselines in its ESDER proceeding which will help offer options to evaluate DR performance in DRAM type programs that are evaluated by CAISO, but retail programs need to quickly adopt these enhancements to better measure the DR that customers, both homes and businesses, are providing. Additionally, CAISO and the CPUC should be encouraged not to stop with these enhancements. ISOs around the country have a broader suite of baselines that allow and appropriately measure curtailment for more types of customer load. To fully embrace DR as a resource that provides grid value we need fully encompassing measurement options.

**D. Resolve Local RA Requirements and Develop an LCA or DLAP Service.** Today there are mismatches between what the CAISO wants to impose as RA requirements on a DR resource and what the CPUC has authorized. This mismatch flows to DR contracts and tariffs and causes a stifling effect on DR growth. If an aggregator builds a resource today – will it still be able to perform at the same level if the requirement moves from Day Ahead to a 20-minute dispatch, as could happen over the course of the 2018-2019 DRAM contracts? Probably not. A 20-minute resource would require more automation, might not drop that quickly and would be eliminated from participating. Uncertainty and changing rules are huge barriers for a resource that require customer participation instead of fossil-fired generation.

As discussed above, an option to provide DR resources across a larger geographic area would be beneficial.

**E. Competitive Parity.** Ensuring that 3<sup>rd</sup> party DRPs and its customers are treated fairly and in a comparable manner to customers of the utilities is very important to maintain a level playing field.

**F. Better Coordination Between CAISO and CPUC.** Today the CAISO and CPUC frequently move at cross purposes to one another – competing local RA requirements is one example of what can come of this. Clearly defined market rules and processes are critical for the success of DR – we need these governing agencies to move forward together with a clear path and advance notice on any rules changes.

## **WHERE SHOULD WE FOCUS OUR EFFORTS LONG TERM?**

### **A. Changing Grid Needs/DR of the Future**

There is a lot of talk about DR of the future. A clear definition of what is needed should be articulated, one which ensures that incentives to customers, the parties always on the other end of this service, align with what is being asked of them.

### **B. DER Integration and Use for T&D Purposes**

We must decide how to stack a DR resources' value to the grid. Today a resource is only valued for T or for D in the DRAM vs the comparative value in the load modifying world. From an efficiency perspective, we should be able to utilize a resource to provide multiple values to the grid. However, how to do that is complicated, including determining how dispatch prioritization would occur is a resource's values are required simultaneously by both the T and the D grid. This issue is applicable to all DER will fall into this category and conundrum.

### **C. IRP vs. Other Procurement**

How procurement will be handled in the future is under consideration. An IRP could result in an all-source solicitation, such as that which was conducted by SCE a few years ago. There is a concern as to how DR resources will be evaluated in that context, as DR resources did not fair well in that all-source solicitation. How do we make room for a resource that is currently valued as short term (DR) under a long-term planning horizon – such as IRP or LTPP? DR must be included in the planning processes – or CA IOUs will always default to buying a generator. Can DR and other DER stand on a level playing field with all resources or should there be a prescribed level of procurement, as in RPS? As noted above, renewables and storage have grown and flourished under their individual mandates. DR which has never had an official mandate, has dwindled. If we do not keep focused DR procurements there must be a mandate to ensure DR does not dwindle further at a time when CA is focused so strongly on Greenhouse reductions.

### **D. CCAs**

The state is facing a significant challenge and a significant opportunity with the explosion of CCA served areas. We must examine how to encourage CCA participation in meeting the states policy goals – including DR growth.

### **E. Residential Participation**

The sheer number of customer participants in the wholesale market could be extremely transformative to the market and pose unique challenges in managing that level of customer volume.

**CONCLUSION:**

The Joint DR Parties appreciate the opportunity to submit these comments for purposes of understanding DR participation to date and some suggestions on improving participation for the future.