UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Demand Response Compensation in Organized Wholesale Energy Markets	))))	**Docket No. RM10-17-000**

COMMENTS OF
THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

The California Independent System Operator Corporation ("ISO") respectfully submits these comments in response to the Commission's Supplemental Notice of Proposed Rulemaking and Notice of Technical Conference ("Supplemental NOPR") issued in the above-captioned proceeding on August 2, 2010,[1] and to address certain issues discussed during the September 13, 2010, technical conference in this proceeding.

I. *Overview*

As explained in the Commission's March 18, 2010 Notice of Proposed Rulemaking ("NOPR"), the objective of the rules proposed in this proceeding is to improve the functioning and competitiveness of the organized wholesale electricity markets by facilitating the active participation of customers in those markets through demand reductions.[2] The proposed rules are intended to build on the Commission's recent efforts in Order No. 719 to promote demand

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1 132 FERC ¶ 61,094 (2010).

2 130 FERC ¶ 61,213 at PP 3-4 (2010).

response in organized markets administered by Independent System Operators ("ISOs") and Regional Transmission Organizations ("RTOs").[3]

The ISO strongly supports the Commission's objective of promoting demand response in wholesale electricity markets. Through an extensive stakeholder process starting in 2008, the ISO developed a Proxy Demand Resource product which allows the bidding of loads or aggregations of load into the ISO's wholesale markets. The Proxy Demand Resource product supplements the ISO's existing Participating Load mechanism and allows wholesale market participation by retail loads that could not as easily qualify or operate as Participating Loads. Consistent with Order No. 719, the Proxy Demand Resource program allows Aggregators of Retail Customers ("ARCs") – called "Demand Response Providers" in the ISO tariff – to submit bids in the ISO's markets comparable to bids submitted by other resources. The Commission recently accepted the Proxy Demand Resource product and found that it complies with Order No. 719:

> We find that the Proxy Demand Resource proposal reduces barriers to participation by allowing Demand Response Providers to submit bids on behalf of retail customers, subject to the CAISO's reasonable restrictions. The Proxy Demand Resource proposal satisfies the general requirements that we set forth in Order No. 719 regarding the ability of ARCs to bid directly in the CAISO-administered markets on behalf of retail customers.[4]

The ISO submitted comments on the Demand Response Compensation NOPR on May 13, 2010. As explained in those comments, the ISO supports the

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3 *Wholesale Competition in Regions with Organized Electric Markets*, FERC Stats. & Regs. ¶ 31,281 (2008) ("Order No. 719"), Order on Rehearing, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292 (2009) ("Order No. 719-A").

4 *California Independent System Operator Corp.*, 132 FERC ¶ 61,045 at P 23 (2010).

Commission's proposal that all demand response resources that successfully bid into wholesale electricity markets should be compensated at the full locational marginal price ("LMP"). The ISO believes that all resource types in wholesale electricity markets should be compensated on the same basis, *i.e.*, at the full LMP. That is exactly the approach for compensating demand response resources which the ISO proposed and the Commission accepted when it approved the Proxy Demand Resource product. The ISO also believes it is appropriate for load-serving entities to be compensated for costs they incur, or revenues that they do not receive, in order to allow demand response resources to participate in wholesale markets. The specific compensation mechanism, however, is steeped in retail regulatory policies and concerns, and the ISO believes these issues are most appropriately addressed by retail regulatory authorities, where feasible.

The Supplemental NOPR seeks comment on whether the Commission should adopt requirements related to two issues addressed in comments: (1) if the Commission were to adopt a net benefits test for determining when to compensate demand response providers, what, if any, requirements should apply to the methods for determining net benefits; and (2) what, if any, requirements should apply to how the costs of demand response are allocated.[5]

First and perhaps most importantly, the ISO urges the Commission to retain the approach it adopted in Order No. 719 and provide each ISO and RTO with flexibility to determine how best to comply with the final rule in this proceeding. Although some regions may elect to adopt a net benefits test, the

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[5] Supplemental NOPR at P 1.

Commission should not mandate a net benefits test. Similarly, cost allocation issues are best addressed on a region-by-region basis. As an ISO located within a single state and without any neighboring organized wholesale electricity markets that would be subject to the final rule, the California ISO is situated differently from all other ISOs and RTOs in the country. The California ISO and its stakeholders consciously designed the Proxy Demand Resource product to avoid certain issues identified by other commenters in this proceeding. The California ISO, with stakeholder support, also concluded that it would be best to allow local regulatory authorities to address certain retail compensation issues related to the participation of Proxy Demand Resources in the ISO's markets. Establishing a "one size fits all" final rule in this proceeding could force the ISO to adopt a fundamentally different design for demand response compensation in order to address issues and concerns that may arise in other parts of the country but that are not relevant to California. The Commission should permit the California ISO to build on its existing efforts to develop demand response in California in coordination with the California Public Utilities Commission ("CPUC") rather than compelling the ISO to abandon the progress made to date.

As explained in more detail below, the ISO strongly believes that the Commission should not require the use of a "net benefits test" for determining when demand response resources will be compensated at the LMP. Demand response products like the California ISO's Proxy Demand Resource product allow Demand Response Providers to aggregate the load of a wide variety of end-use customers. These end-use customers take service under many different retail rate schedules, making it extremely difficult to accurately assess the underlying cost structure of the loads that comprise the aggregate demand response resource. As a result, it would be extremely difficult for the ISO to develop, manage, and implement a meaningful "net benefits" analysis that could assess the overall net benefits to customers upon the ISO's acceptance of a demand response bid. Because many of the potential costs and benefits relate to retail rates, and because retail rates vary considerably by customer class, an ISO or RTO could develop, at best, only the roughest approximation of the net benefits provided by a demand response resource in any given hour, assuming the ISO or RTO has relevant and timely retail rate information on each of the underlying end-use customers that make up a demand response resource. Where feasible, the ISO strongly believes these issues are more appropriately addressed by state utilities commissions like the CPUC and other local regulatory authorities.

The ISO understands that the issue of a net benefits test is closely related to the so called retail "missing money" issue which results from an unavoidable interaction between the compensation that demand response resources receive in wholesale markets and the retail rates paid to load-serving entities. Although some regions may choose to address the retail "missing money" issue by subtracting retail rate components from the full LMP paid to demand response resources, that approach – by necessity – is an inefficient, "rough justice" solution to the retail missing money issue. In California, the CPUC has already begun efforts to address this issue at the retail level. Where feasible, the

Commission should permit ISOs and RTOs to allow local regulatory authorities to address this issue.

The ISO also believes that the Commission should not establish a uniform approach to allocating the costs of demand response resources. Many of the issues involving cost allocation discussed at the September 13 technical conference appear to be closely related to the question of whether demand response programs will result in a double payment for demand curtailments – which are measured as the difference between the anticipated level of demand but for the curtailment and the actual real-time demand – if the end use customers' charge incorporates one payment made to the demand response resource and another payment to the relevant load-serving entity for the same component of energy. Where demand response compensation in wholesale electricity markets is accompanied by such a double payment, there is a resulting revenue shortfall which must be addressed through a settlement uplift mechanism. As explained below, the California ISO's Proxy Demand Resource design does not include such a double payment or a resulting revenue shortfall due to the settlement mechanism the ISO employed to resolve this double payment concern, which is called the "Default Load Adjustment" In the ISO tariff. Any directives in the Commission's final rule related to cost allocation for double payment-related uplift charges should recognize that such uplifts are not universally applicable to ISO and RTO demand response products if the products were designed to resolve these concerns in the first instance.

Thus, the point above highlights that the Commission must proceed cautiously as the methodology for allocating to customers the costs of compensating demand response resources must take into account differences in the specific demand response product designs implemented by each ISO or RTO and the differences in the general energy and ancillary services wholesale market designs which each ISO or RTO has implemented. The Commission has never required uniformity in the manner in which the costs of procuring energy from other resources are allocated by ISOs and RTOs. The ISO does not believe there is any basis for mandating uniformity in allocating the costs paid to demand response resources in wholesale electricity markets.

II. *General Comments*

Many of the issues identified in the Supplemental NOPR and discussed at the September 13 technical conference relate to two concerns that arise out of the interplay between wholesale electricity markets and retail regulation of electric utilities: the potential for double payments in a demand response program and the so-called "missing money" issue. The California ISO and its stakeholders considered both issues in the development of the Proxy Demand Resource product and adopted design features that address the double payment concern while recognizing that, in California, local regulatory authorities like the CPUC are the proper entities to address the missing money concern on the retail side. A simple example illustrates these concerns.

Assume that a Demand Response Provider ("DRP"), DRP-1, is submitting demand curtailment bids for the load of multiple retail customers of a load-serving entity ("LSE"), LSE-2. DRP-1 bids 10 MWh of demand curtailment from those retail customers. LSE-2 forecasts that, under normal circumstances without any demand curtailment, its load will be 100 MWh in a given hour, so LSE-2 submits offers to purchase 100 MWh in that hour.[6] One hundred MWh of supply clears the wholesale market, based on LSE-2's offer – 90 MWh from generation resources and 10 MWh of demand curtailment from DRP-1. DRP-1 receives the LMP for the 10 MWh that cleared the wholesale market. LSE-2 pays for the 100 MWh of load awarded in the day-ahead market.

Assuming perfect performance by the curtailing customers, DRP-1 curtails 10 MWh of load, which is paid as energy supply by the wholesale market. LSE-2 procured 100 MWh of load, but, as measured by meter data, its customers only consumed 90 MWh. It appears that LSE-2 over-procured; therefore, LSE-2 would receive an uninstructed energy payment for the 10 MWh of over-procurement through the wholesale market settlement. Since both LSE-2 and DRP-1 received compensation associated with the 10 MWh demand curtailment, there would be a double payment. While the demand response regimes adopted by some RTOs can result in such a double payment, the Proxy Demand Resource product recently approved by the Commission applies an adjustment (the "Default Load Adjustment") in the uninstructed energy settlement pre-calculation for LSE-2 to ensure that only the Demand Response Provider (*e.g.,* DRP-1) is compensated for the real-time demand reduction of the curtailing customers (the Proxy Demand Resource). This design mechanism eliminates

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6 Because DRP-1 is a separate market participant from LSE-2, LSE-2 has no knowledge of the demand curtailment bids submitted by DRP-1.

the need for an uplift charge to be allocated through the ISO wholesale market settlement.

At the retail level, only 90 MWh of load is metered, and so the retail customers of LSE-2 (including those retail customers whose curtailment comprised the resource which DRP-1 bid into the wholesale market) only pay LSE-2 for 90 MWh at the full retail rate. However, LSE-2, which procured 100 MWh of energy in the wholesale market to serve its expected load, only receives compensation from its retail customers at the retail rate for 90 MWh. The difference between the wholesale cost of procuring 100 MWh of energy and the compensation for 90 MWh of metered load at the retail level results in a potential loss of revenue to LSE-2; this is the retail “missing money” concern.

This example illustrates one of the primary issues involving demand response being debated across the country – whether and how much a load-serving entity should be compensated for energy that it procured in a wholesale market but that was subsequently sold back to the ISO or RTO by a third-party demand response provider. In essence, the demand response provider never paid for the energy it sold in the first instance. The analogy for generating resources is a generator that sells energy to the ISO or RTO yet never has to pay the fuel supplier. Compensating the demand response provider for the energy provided by the demand response provider without appropriate compensation to the load-serving entity obfuscates the true cost of energy, which can lead to economic inefficiencies and market manipulation.

Some commenters have suggested that the wholesale markets should adjust the compensation for demand response resources, so that demand response resources receive the LMP less certain components of the retail rate. This concept is often referred to as compensation at "LMP minus G" (where G stands for the generation component of the retail rate) or "LMP minus T and G" (where G and T stand for the generation and transmission component of the retail rate).

The ISO and its stakeholders, including the CPUC, are keenly aware of the retail "missing money" concerns associated with demand response compensation. In the development of the ISO's Proxy Demand Resource product, there was substantial consensus among stakeholders that the ISO should compensate all resources in the wholesale market in the same way by paying the full LMP. The ISO and stakeholders also recognized that compensation between the load-serving entity and Demand Response Provider to resolve the retail missing money concern still needed to be addressed for Proxy Demand Resources, but this would be addressed according to the policies, rules and regulations of the applicable local regulatory authority. Consistent with this conclusion, there is no mechanism in the recently-approved Proxy Demand Resource regime for the ISO to attempt to derive and apply a "minus G" value in its settlement process. Instead, this component is addressed outside of the wholesale market by arrangements between the Demand Response Provider and load-serving entity, under the auspices of the local regulatory authority.

The stakeholder concern with the ISO deriving a "minus G" value (or a "minus G and T" value) and subtracting it from the payment to demand response resources was two-fold. First, the ISO and stakeholders well understood the cost compensation concerns associated with wholesale demand response resources. ISO stakeholders concluded that cost compensation mechanisms, such as subtracting a component of a "retail rate," was an important concern that was best resolved by the local regulatory authority, since managing and coordinating retail rates at the wholesale level would be costly, resource intensive, and error prone, especially considering that retail rate designs not only vary by load-serving entity and customer type, but that retail rates often change. Second, stakeholders concluded that any "minus G" value the ISO derived would simply be a rough approximation of the actual retail revenue impact to load-serving entities. The issue of what component of a retail rate should be subtracted, and how much, is especially complex if a demand response resource is made up of an aggregate of multiple end-use customer types, *e.g.*, small and large commercial customers, that take service under different retail rate schedules. Because the mix of different retail customer classes included in a wholesale demand curtailment bid may vary from hour-to-hour, the ISO could never develop a "minus G" component that truly tracks the retail revenue impact to load-serving entities. In addition, because any "minus G" value applied by the ISO will not necessarily be sanctioned by the local regulatory authority, parties to a demand response transaction may need to develop a contract for differences around the ISO's LMP minus G value, regardless of the final "minus G" approach incorporated into the ISO wholesale market settlement. For all these reasons, the conclusion of the ISO stakeholder process was to allow the retail "missing money" concern to be addressed through the local regulatory authority, enabling the ISO to avoid delving into retail rate issues and avoiding the need for continual coordination on retail rates with the local regulatory authority. The preference that the ISO avoid delving into retail rate issues is somewhat akin to the caution the Commission expressed in Order No. 719 that ISOs and RTOs should not be required to interpret whether the law of the local regulatory authority prohibited or constrained the retail customer from participating in the regional organized market.[7]

The ISO urges the Commission to refrain from requiring ISOs and RTOs to subtract a retail rate component from the LMP paid to demand response resources. Instead, the final rule in this proceeding should provide ISOs and RTOs with the same flexibility the Commission provided in Order No. 719, where the Commission recognized that it is important to allow each ISO or RTO to design demand response provisions that account for regional differences.[8] Demand response is inextricably linked to retail rate structures and the rules and regulations of local regulatory authorities. The ISO understands that, in certain regions, given the number of states and local regulatory authorities involved, it may be more pragmatic for certain ISOs or RTOs to subtract a value that

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[7] See Order No. 719 at P 49, fn. 78 ("The RTO or ISO should not be in the position of interpreting the laws or regulations of a relevant electric retail regulatory authority.")

[8] Order No. 719 at PP 158-159; *see also* Order No. 719-A at P 67 ("Each RTO or ISO is required to work with its stakeholders to propose methods of implementing this requirement in its region. The intent of the Final Rule is not to interfere with, undermine, or change existing demand response programs.").

approximates the “minus G” portion of the consumers’ retail rate. However, the situation is different in California. In California, the ISO operates within a single state, interfaces with a single state public utilities commission, and does not have other neighboring ISOs or RTOs with organized wholesale electricity markets creating potential “seams” issues. Moreover, while state commissions in some regions support a federal approach to addressing the retail “missing money” issue, in California, the state regulatory authorities are intending to address this issue head-on at the retail level. The CPUC is deeply engaged in the matters of wholesale-retail demand response compensation concerns and is working with the ISO and California stakeholders on these matters. The Commission should allow these efforts to continue.

Requiring the ISO to subtract retail rate components from the compensation paid to Demand Response Providers could undermine the value of over two years of effort on the Proxy Demand Resource product. As a case in point, the ISO did not develop its Demand Response System infrastructure for the implementation of its Proxy Demand Resource product to include functionality that would enable the calculation and/or submission of retail rates into the settlement of Proxy Demand Resources. Redesigning the ISO’s recently-implemented Demand Response System to accept, manage, and calculate weighted average retail rates that would be subtracted from payments for Proxy Demand Resources was not anticipated. In order to do this, the ISO would have to develop a multi-party settlement approval workflow process because: (1) retail rates can differ by settlement hour, (2) the Demand Response

Provider would need a way to provide the actual effective retail rate for each hour prior to the results going to the settlement system, and (3) the load-serving entity would want to review/validate the retail rate (since it is actually their rate) prior to ISO settlement.

Developing the market rule changes and designing, testing, and implementing the related system changes would be costly and introduce uncertainty and delay the development and approval of new Proxy Demand Resources due to the complexity of establishing both stakeholder processes for determination/submittal/validation of the "G" component and major changes to fundamental ISO Demand Response System process/application functionality along with wholesale charge code changes to the ISO's Settlements and Market Clearing systems to incorporate a new pricing settlement specific to Proxy Demand Resources. The ISO anticipates that altering its systems, tools, and market rules would take at least a year, during which potential Demand Response Providers would be faced with unanticipated regulatory uncertainty and would have lost the benefits of relying on the Commission's recent order approving the Proxy Demand Resource product in California as designed.

Mandating such an approach in California could have other adverse consequences for potential Demand Response Providers. Today, the ISO performs an initial settlement of its market by noon at T+5 business days. The ISO would expect this approval process between the multiple parties to a demand response transaction to take longer than 5 business days. In fact, PJM allows up to 60 days for the Curtailment Service Provider to submit data to PJM, including meter data, retail rate information, and line losses. PJM then sends the daily settlement with hourly data to the electricity distribution company and load-serving entity, each of which has ten business days to review the data. If the Commission were to mandate a "minus G" settlement construct across all ISOs/RTOs, demand response resources in the California ISO markets would be subject to a "different" settlement and payment schedule, and possibly credit requirements, than the schedule that applies to all other resource types. This would result in market inefficiencies.

For similar reasons, the Commission should not require ISOs and RTOs to adopt a net benefits test to determine when demand response resources are paid the full LMP. As an initial matter, the ISO notes that commenting on the general concept of a "net benefits test" for determining when or how to compensate demand resources is difficult without making certain assumptions as to the nature and type of net benefits test or tests that the Commission is contemplating. For example, the Commission might propose a net "societal" benefits test or a total resource cost test. In the alternative, a "net benefits test" could be strictly based on the impact a demand response resource has on wholesale market prices. Each such alternative "test" would have different evaluation methods and policy outcomes. A related question is the extent to which externalities or non-monetary benefits, such environmental benefits, would be incorporated into such a cost-benefit analysis.

No matter what variation of a net benefits test is contemplated, the ISO believes that the administrator of the wholesale markets is not in a position to develop a truly meaningful test of the net benefits of demand response resources. Under the California ISO market rules, individual retail customer loads will largely be managed by the Demand Response Provider. The ISO's expectation is that the ISO will largely interface with Demand Response Providers, not individual retail customers. Under this paradigm, it will be extremely difficult to develop a meaningful net benefits test. In theory, if a Demand Response Provider is dealing with only a single retail customer, or perhaps a homogenous group of similarly-situated retail customers, then the ISO may be able to glean certain cost and benefit information from those customers such as the specific retail rate those customers are on, the specific end-uses being curtailed, the characteristics and associated environmental impact of those end-uses, the depth and duration of the load shed employed, *etc.* to derive "net benefits." However, the ISO's Proxy Demand Resource product is designed to facilitate wholesale market participation by large, aggregated demand response resources. Developing a mechanism for valuing the net benefit from wide and diverse sets of aggregated retail customers would be extremely challenging and likely would have limited utility for determining when or how much to pay a particular demand response resource.

For instance, under the aggregated demand response resource paradigm, attempting to calculate a single "generation rate" value based on multiple retail rates and customer classes (or some other customer marginal cost values) would be very challenging. The best an ISO or RTO could accomplish is a rough approximation of these values, which may or may not be accurate or acceptable to the local regulatory authority. The local regulatory authority may insist on additional compensatory measures be taken to resolve differences between the Demand Response Provider and the load-serving entity, regardless of the net benefit model employed by an ISO or RTO.

In light of these challenges, the ISO believes it is far preferable to treat demand response resources like other resources and compensate them at the full LMP. This will result in efficient market outcomes taking into account only the drivers of the wholesale electricity markets. To the extent there are related retail market impacts or societal costs and benefits, local regulatory authorities – at least in California – are better situated to address these issues through the retail regulation of demand response compensation.

Refraining from a mandatory net benefits test for demand compensation is also consistent with the Commission's findings in Order No. 719. In that rulemaking, the Commission held that issues involving the "net benefits" of a demand response program are "more appropriately addressed by each region in its compliance filing if it chooses to do so."[9] Any findings concerning net benefits tests in the final rule in this proceeding should provide similar regional flexibility to ISOs and RTOs and should allow each region to determine whether a net benefits test is warranted given state retail considerations and wholesale market issues in that ISO or RTO.

On the issue of cost allocation, the ISO notes that the Commission recently addressed the allocation of demand response compensation costs in its order accepting the Proxy Demand Resource product. The Commission

[9] Order No. 719 at P 159.

accepted the ISO's proposal to compensate Demand Resource Providers at the appropriate LMP for the Proxy Demand Resource and to allocate the costs of procuring Proxy Demand Resources to the load-serving entity within the relevant Default Load Aggregation Point.[10] The Commission also directed the ISO to undertake a study of the effects of demand response from Proxy Demand Resources outside of the Default Load Aggregation Point and to submit a report on this study to the Commission for informational purposes.[11]

The Commission order accepting the cost allocation rules associated with the Proxy Demand Resource product is an example of the Commission's standard approach to cost allocation issues under ISO and RTO wholesale electricity markets. The Commission has historically allowed significant regional flexibility on cost allocation rules as appropriate to reflect the differences in the specific market designs implemented by each ISO or RTO. Indeed, this approach is consistent with the general structure of the Federal Power Act, which allows each public utility the flexibility to establish its own rates, terms and conditions of jurisdictional services providing the resulting rates are just and reasonable and not unduly discriminatory. The ISO respectfully submits that there is no reason to adopt a different approach for demand response cost allocation. As such, the ISO urges the Commission to avoid promulgating a standardized cost allocation methodology in its final rule in this proceeding.

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[10] 132 FERC ¶ 61,045 at PP 32-35.

[11] *Id.* at P 34 ("In light of the potential market-wide impacts of demand response, we direct the CAISO to undertake a study to determine if the effects of demand response apply more broadly than to the individual load-serving entity in which the Proxy Demand Resource is located. The study should include an analysis of 12 months of actual market data of Proxy Demand Resource participation in the CAISO's markets.").

III. *Responses to Specific Questions on a Net Benefits Test*

In addition to the comments above, the ISO offers the following responses to specific questions in the Supplemental NOPR related to a net benefits test:

1. Some commenters address the need for a net benefits test. Address why the Commission should adopt a net benefits test for determining demand response compensation, and what the objectives of any such test would be.

For the reasons explained above, the Commission should not mandate a net benefits test for determining when and how to compensate demand response resources.

2. How to define benefits, including whether the benefits associated with demand response should account only for lower market-clearing prices in the day-ahead and real-time markets or should also include consideration of operational benefits (e.g., lower reserve requirements), societal benefits or another measure.

As explained above, the ISO believes it would be extremely difficult to develop a meaningful assessment of the benefits of demand response resources.

3. In addition to the payments received from the wholesale market, what are the costs demand response providers and load serving entities incur and should these be included for purposes of a net benefits test.

This question highlights the fundamental problem the Commission or an ISO or RTO will have in settling on a specific net benefits test. Determining which costs and benefits should be included in any test would be a very subjective exercise. Moreover, because the ISO will not manage which mix of retail customer classes are included in a demand response resource bid, and because the impact on retail compensation to load-serving entities is based on factors under the control of local regulatory authorities, any evaluation of the net benefits of selecting a demand response resource will be, at best, a very rough approximation of the actual net benefits and not particularly useful in practice. For example, it would be extremely difficult for any ISO or RTO to ever know and/or validate the costs of one demand response resource versus another. It would be very costly for ISOs and RTOs to develop mechanism to collect this type of date and even if such data is collected, there would necessarily be substantial uncertainty as to the accuracy of some of the collected data.

4. How to identify the beneficiaries of demand response, and how the allocation of costs related to demand response compensation affect the beneficiaries, if at all.

Under the ISO's Proxy Demand Resource design, each demand response resource is modeled as a generator and is treated the same as other supply-side resource. Like other supply-side resources, bids from Proxy Demand Resources are accepted by the ISO's market software as part of the optimized market dispatch of all resources to meet system needs. As such, the beneficiaries of Proxy Demand Resources are similar to the beneficiaries of any resource, and the ISO has adopted (and the Commission accepted) analogous cost allocation rules for Proxy Demand Resources.

5. Whether any net benefits methodology adopted should be the same for all ISOs and RTOs or whether the individual circumstances or configuration of each ISO and RTO would support a different net benefits methodology.

As explained at greater length above, the ISO not only believes that the Commission should not mandate a net benefits test, but also believes that the

Commission should provide ISOs and RTOs with significant flexibility to determine how best to comply with any requirements in the final rule based on the unique needs of each region. This is consistent with Order No. 719, where the Commission recognized that it is important to allow each ISO or RTO to design demand response provisions that account for regional differences.[12]

6. Proposed methodologies for implementing a net benefits test. Comments also should consider whether a net benefits threshold should be established up front based on static measures, such as a specific price or number of peak hours, or established on a dynamic basis, such as a price threshold based on a pre-set heat rate and daily updated fuel price; and similarly, whether the net benefits should be an explicit test run by the ISO or RTO either after bids have been received or each hour prior to accepting demand response bids. Comments should also describe the advantages and limitations of any proposed net benefits methodologies.

For the reasons explained above, the Commission should not mandate a net benefits test for determining when and how to compensate demand response resources.

IV. *Responses to Specific Questions on Cost Allocation*

In addition to the comments above, the ISO offers the following responses to specific questions in the Supplemental NOPR related to cost allocation issues:

(1) Whether standardizing demand response compensation among ISOs and RTOs requires simultaneous standardization of a method for allocating the costs associated with such compensation. In addition, whether standardizing demand response compensation among ISOs and RTOs requires consideration of corresponding settlements and other impacts associated with the compensation mechanism.

[12] Order No. 719 at PP 158-159; *see also* Order No. 719-A at P 67 ("Each RTO or ISO is required to work with its stakeholders to propose methods of implementing this requirement in its region. The intent of the Final Rule is not to interfere with, undermine, or change existing demand response programs.").

Consistent with Order No. 719, the ISO believes that the Commission should provide ISOs and RTOs with significant flexibility to determine how best to comply with any requirements in the final rule based on the unique needs of each region. Such flexibility is particularly important when it comes to cost allocation issues, as ISO/RTO settlement rules are complex and often reflect unique characteristics of each region's market design.

As explained above, the ISO opposes any requirement that demand response resources be compensated by an ISO or RTO on an "LMP minus G" basis. If the Commission does issue such a mandate, however, the final rule should also include general guidance on how to allocate additional costs resulting from such an approach. For example, in simple terms, if an ISO/RTO clears $100 worth of supply resources in the Day-Ahead market, then the ISO/RTO will collect $100 from the buyers so that it can pay $100 to the suppliers. But if the ISO/RTO only pays the suppliers $90 because it subtracted a "minus G" portion from some of the demand resources, then the ISO will have an imbalance of $10; in other words, the ISO/RTO will not be revenue neutral. Thus, the ISO /RTO will have to fairly allocate those monies to market participants in a just and reasonable manner. The Commission would need to consider if a just and reasonable allocation is giving the $10 back to all load-serving entities, or should the $10 be allocated to only those load-serving entities that had customers enrolled in a wholesale demand response resource. If the Commission mandates the latter approach, and if the "minus G" portion subtracted from the LMP is greater than or less than the actual load-serving entity's retail rate, then issues could arise if one load-serving entity is enriched due to the rough justice nature of any "minus G" value that the ISO/RTO might apply.

> (2) If the Commission standardizes an approach for allocating the costs associated with requiring payment for demand response, what type of approach is appropriate. Comments should address the specific approaches delineated above, and may address other broad principles the Commission could use to determine the cost allocation method.

Although the ISO generally supports compensating demand response resources in the wholesale market at the full LMP (with appropriate mechanisms such as a "minus G" adjustment to address load-serving entity impacts on the retail level), the ISO also believes each ISO or RTO should have flexibility to determine specific details of the demand response compensation mechanism to address the unique features of each ISO/RTO market design and the needs of each region. To the extent, the Commission adopts a more proscriptive approach to demand response compensation in the final rule (*e.g.*, mandating "LMP minus G" compensation), the Commission should provide additional guidance on the cost allocation methodology or methodologies that the Commission would view as appropriate. In the absence of a specific compensation method, however, it is difficult for the ISO to provide comments on the principles the Commission should use to evaluate a cost allocation proposal.

> (3) How the use of a net benefits test would affect the need for and methodologies for determining cost allocation.

As explained above, the Commission should not mandate a net benefits test for determining when and how to compensate demand response resources. Because of the wide range of possible net benefits tests that could be employed, it is difficult to provide helpful comments on how a net benefits test would affect cost allocation methodologies.

V. *Conclusion*

As noted above, the ISO strongly supports the Commission's objective of promoting demand response in wholesale electricity markets. The ISO respectfully requests that the Commission consider the comments above and provide ISOs and RTOs with regional flexibility to determine how best to address any demand response compensation directives in the Commission's final rule in this proceeding.

Respectfully submitted,

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Dated: October 13, 2010