BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769.	Rulemaking 14-08-013 (Filed August 14, 2014)

COMMENTS OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION ON DISTRIBUTION RESOURCES PLANS PURSUANT TO RULEMAKING R.14-08-013

Roger E. Collanton
General Counsel
Anna A. McKenna
Assistant General Counsel
Judith B. Sanders
Senior Counsel
Jordan Pinjuv
Counsel
California Independent System
Operator Corporation
250 Outcropping Way
Folsom, CA 95630
T – (916) 608-7007
F – (916) 608-7222
jsanders@caiso.com

Attorneys for the California Independent
System Operator Corporation

September 5, 2014

Table of Contents

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769.	Rulemaking 14-08-013 (Filed August 14, 2014)

COMMENTS OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION ON DISTRIBUTION RESOURCES PLANS PURSUANT TO RULEMAKING R.14-08-013

I. INTRODUCTION

The California Independent System Operator Corporation (CAISO) is pleased to support the Commission in convening a timely and important proceeding that will be instrumental in helping to achieve California's energy and environmental policy goals. This distribution resources plan (DRP) proceeding fills a critical need to comprehensively understand the impacts of distribution energy resources (DER) on the distribution system and prepare utility distribution companies (UDCs) to facilitate and benefit from their integration.

As the volume and diversity of DER increase, DER will dynamically alter both the amount and the variability of energy flowing between the distribution and transmission systems, requiring closer coordination between the CAISO and the UDCs to maintain reliability and facilitate economic transactions. Areas of focus include:

- forecasting and visibility of DER;
- operational dispatch coordination;
- operating procedures, measurement and accounting approaches for DER providing services to both the CAISO and UDC;
- identifying optimal DER locations, taking into account resource deliverability and effectiveness results from CAISO planning studies; and
- evolution of distribution system operating standards analogous to the NERC standards for the transmission system.

In the next section, the CAISO offers some background and context for its later comments in response to the Commission's specific questions. Specifically, the CAISO

(1) describes the importance of enhancing distribution system operation and planning to facilitate the expansion of diverse DER, (2) identifies specific aspects of DER expansion that will affect core CAISO functions and responsibilities, (3) identifies key issues for this proceeding that are "cross-cutting" in the sense that they apply to multiple other proceedings and initiatives, (4) suggests how to distinguish near-term issues that the IOUs should address in their required June 2015 DRP filings, versus issues that are broader in scope and will likely take longer to resolve, and (5) identifies some salient industry trends that will shape distribution system operation and planning in the future high-DER electric system. In the final major section, the CAISO offers its responses to the specific questions posed by the Commission.

II. BACKGROUND COMMENTS AND OBSERVATIONS

A. This proceeding is timely and important to achieving California's energy and environmental policy goals.

California enacted policies to reduce GHG emissions using several measures including increasing reliance on renewable supply technologies and expanding the penetration of various distributed energy resources (DER) including electric vehicles, storage, and distributed generation. These measures require state agencies, the CAISO, industry participants and stakeholders to understand the significant impacts they will have on the operation and planning of the electric supply and distribution system and take action to prepare for these impacts.

The anticipated high volumes and great diversity of DER, located both in front of and behind the end-use customer meter, are challenging the key assumptions upon which the distribution system was built and operated, namely, that energy supply originates in large central-station power plants and travels one way over transmission and distribution circuits to the customer. Yet, until the issuance of this DRP OIR, California has had no proceeding or other policy venue to comprehensively understand and address the impacts high DER proliferation will have on distribution system operations and planning and on the grid more generally.

This DRP OIR is also well-situated to address certain "cross-cutting" issues arising in several other DER-related proceedings. By focusing directly on the distribution system rather than on any specific type of DER, this OIR can identify and value products and services needed for distribution system operation that DER with

suitable performance characteristics could provide. This proceeding can then inform specific DER policy forums including demand response, storage procurement, energy efficiency and alternative fueled vehicles, to help them identify benefits and develop associated revenue streams available to DER projects based on their performance capabilities, or, where appropriate, specify interconnection requirements.

B. Utility DRPs need to address enhanced coordination with the transmission grid operator.

Greater amounts and diversity of DER will require enhanced operational and planning coordination between the UDCs and the CAISO. Resources connected to the distribution system dynamically add to or reduce both the amount and the variability of supply required from the transmission system. The utility DRPs need to address enhanced transmission-distribution coordination as described in the following paragraphs.

First, the high-DER distribution system will need to continue to interface reliably with the CAISO grid. Many of the resources on the distribution side of the transmission-distribution interface will be operating outside of the CAISO market, requiring UDC-CAISO coordination to accurately forecast DER output and provide visibility in real time. Power flows at the interfaces will become more variable, and in some areas power flows between the transmission and distribution systems may reverse direction from one time interval to another.

Second, many different types of DER are seeking to participate in the CAISO energy and ancillary services markets either because they want to offer resource adequacy and flexible capacity to load serving entities or because there is a business case for market participation. The CAISO market models these resources as if they were connected to the transmission-distribution substation and dispatches them on that basis. As the amount and diversity of participating DER increase, the CAISO and the UDCs will need increased operational coordination to prevent any adverse impacts of CAISO dispatches on the distribution system. Similarly, the CAISO will need to know when the UDC dispatches a resource for local reliability needs and thereby impacts its availability for dispatch by the CAISO.

Third, participants in the CPUC's DR and energy storage proceedings have argued that these types of DER can provide services to both the distribution and the

transmission systems. For a resource to serve both systems, in addition to new or enhanced UDC-CAISO operating procedures to prevent operating conflicts, measurement and accounting methods will be needed to validate resource performance and provide appropriate compensation for these services and allocation of the costs of such services.

Fourth, optimal DER location should be coordinated with resource deliverability and effectiveness results from CAISO planning studies, especially for those DER seeking to provide resource adequacy and flexible capacity to load-serving entities. The deliverability criterion captures the ability of a supply resource to generate energy under peak load conditions without violating transmission constraints or causing the curtailment of other deliverable resources. On this basis the resource can qualify to provide resource adequacy capacity. The effectiveness criterion determines how effective a supply resource is, due to its location, for resolving transmission constraints in the local capacity areas. Both of these locational attributes are crucial to determining a resource's locational value.

Fifth, with regard to the deliverability attribute, the CAISO conducts an annual distributed generation deliverability procedure to identify areas of the CAISO system where additional distributed generation could receive deliverability status for resource adequacy purposes without further engineering studies to assess impacts on the CAISO grid. This procedure utilizes renewable generation portfolios ("RPS portfolios") created by the CPUC for transmission planning purposes, each of which includes a quantity and geographic distribution of expected development of distribution-connected generation. Some developers of distributed generation have pointed out, however, that the locations designated in the RPS portfolios and assessed for deliverability through the CAISO's procedure could be better aligned with the more promising development areas. The DRP proposals to be filed next year should improve this alignment.

Sixth, there may be misalignments or gaps between NERC standards that apply to the bulk electric system (with primary implications for the transmission system) versus standards that apply to the distribution system (such as earlier versions of IEEE 1547 ride-through requirements). There may be a need for the CPUC to develop distribution system operating standards analogous to the NERC standards for the bulk electric system.

C. This proceeding can address foundational, cross-cutting issues that affect multiple types of DER.

Some major issues are arising, with slight variations, in multiple CPUC proceedings and other venues dealing with specific types of DER. Such issues are foundational or cross-cutting in the sense that they reflect common challenges across the range of DERs, or are inherent in the evolution of the electricity system itself.

One such cross-cutting issue is how to define, value, and monetize the services different DER types can provide to the distribution and transmission system. Many developers indicate that the current framework does not offer clear revenue opportunities for DER that have the capability to provide reliability support services. The DRP proceeding can help address this by identifying distribution system needs and DER-provided services that can fulfill these needs. Services could include, among other things, voltage support, phase balancing, and thermal overload management. Through the DRP proceeding, such distribution needs and services can be identified and described in terms of required operating characteristics of the DER, rather than in terms of DER technology or type. These requirements can then inform related DER policy-making forums including demand response, storage procurement, energy efficiency and alternative fueled vehicles to more specifically define revenue opportunities for DER with the needed operating characteristics.

Another foundational issue is the question of responsibility and accountability for reliability in a future where customers may have different reliability needs and preferences. Will service reliability remain a public good to be maintained at a high standard across the entire system, when technology may make it easier for customers to tailor service reliability and the associated cost to their specific needs? How then should responsibility for service reliability be allocated, enforced, and maintained? More specifically, what is the new paradigm for customer service reliability, and what is the appropriate role for the UDC to support different customer service reliability preferences?

A third issue is how to coordinate distribution and transmission planning under a high-DER electric system scenario. Today's transmission system reliability and operating standards are based on total gross system load, regardless of the amount of end-use customer load that is served by local or behind-the-meter supply resources. This

existing paradigm is reasonable in a system where nearly all electricity flows one way from central station generators to end-use customers. But under a high-DER scenario, is it reasonable for the transmission operator to remain responsible for planning and serving the gross load, or is it more appropriate and efficient to limit the transmission operator's responsibility to planning and serving only the net load at the transmission-distribution interfaces? Even without a shift in the planning paradigm, how will information, responsibility, and determination of optimal infrastructure investments be coordinated across the transmission-distribution interface?

D. The Commission should recognize near-term and longer-term objectives and establish additional phases to address the full scope outlined in the More Than Smart paper.

The DRP OIR, which includes the More Than Smart paper, correctly describes the full scope and magnitude of the challenges and opportunities presented by the anticipated proliferation of diverse DER in California. Specifically, the OIR and the More Than Smart paper set out to address the redesign of distribution system operation and planning for the 21st century. At the same time, the OIR has a more limited near-term objective, which is to provide guidance to the IOUs for developing AB 327 compliance filings by June 2015 that will help to facilitate the expansion of DER in California.

Given these dual objectives and the full scope described by the More Than Smart paper, the CAISO suggests that the CPUC consider scheduling either a second phase of this OIR or a subsequent OIR. The CAISO offers the following suggestions to help the CPUC distinguish the near-term objective of providing guidance for the IOUs' DRP filings, from the comprehensive set of issues required for distribution system operation and planning with high penetration of DER.

1. The IOUs' June 2015 DRP proposals should emphasize existing distribution system infrastructure and operational capabilities, and current regulatory rules and processes, with only minor enhancements.

In order to facilitate near-term expansion of DER, the DRP proposals must identify potential locations and approaches for DER development that do not require significant enhancements to distribution infrastructure and operation, or major changes to regulatory rules and procedures that are not already in progress.

As mentioned above, an important linkage must be made to the CAISO's annual distributed generation deliverability process, specifically to enhance how the CPUC models distributed generation development scenarios in the RPS portfolios the CAISO uses for the transmission planning process. Because the CAISO performs the distributed generation deliverability process annually using the same RPS portfolios, it would be valuable in the near term to improve the representation of distributed generation quantities and geographic distribution in the RPS portfolios to align better with the actual areas where developers will be developing projects. Better alignment would ensure that the CAISO tests for available capacity to support the deliverability status of new resource additions in the areas where distributed generation development is preferred.

Another valuable near-term benefit the DRPs could provide is a procedure for the IOUs to track or monitor the actual build-out of DER and compare their progress against the targeted in-service dates to monitor and alert planners of situations where targeted dates appear to be delayed. Such tracking and monitoring is especially important where preferred DER have been procured to meet anticipated needs for capacity or to substitute for a needed transmission system upgrade.

2. Issues that comprise the more comprehensive scope of distribution system operation and planning require a second phase of this proceeding.

Section IV of the More Than Smart paper offers an "Integrated Grid Roadmap" comprised of several parallel streams of activity extending well into 2017 and beyond, to develop the operational and planning elements of a 21st century high-DER electric system. The CAISO believes that more detailed specification of this roadmap – described further below in the CAISO's responses to the Commission's questions – represents an important next step in this proceeding, but is not needed in order to provide effective guidance to the IOUs in the near term for their June 2015 DRP filings. Even if the OIR were able to flesh out more details of the Integrated Grid Roadmap over the next few months, the activities entailed in its implementation will be in their very early stages at best and not able to contribute much to the Commission's planned January 2015 guidance order to the IOUs.

The CAISO further believes that the three cross-cutting issues mentioned in Section C above will take longer to resolve than the time frame of the January 2015

guidance order, and are not needed to provide effective guidance to the IOUs for their 2015 filings. For example, the question of products and services that DER can provide to distribution system operation can be explored over the next few months, but to develop the ideas to the point of specifying new revenue streams for DER will require further development of the operational needs of the UDC in the high-DER context, followed by new regulatory provisions to incorporate these needs into procurement requirements. Similarly, questions about coordination of transmission and distribution planning, and about different possible paradigms of reliability for the high-DER system, are very important matters this OIR raises, but will require more time to fully explore and resolve.

E. A provisional or "working" vision of the future high-DER electric system can help structure the comprehensive agenda of this OIR.

Ideally, for addressing a question as large and far-reaching as distribution system planning and operational changes to accommodate the high numbers and diversity of DER, it would be beneficial to have a reasonable working vision of the end state. Unfortunately the current rates of technological change and the diversity of new models and use cases being suggested by DER developers make any such vision highly speculative at this moment. As a result, parties could easily waste time and effort trying to arrive at a consensus working vision instead of settling on one that is good enough. At the same time, there are several emerging trends that we can feel fairly confident about since their current trajectories appear to be both feasible and desirable for achieving California's energy and environmental goals. These emerging trends should be kept in mind as the DPR OIR proceeds to accomplish both its near-term and longer-term objectives. Specifically:

1. End-use customers will continue to adopt technologies that give them more choice and control over how they use and obtain energy.
2. Technological changes will continue to proceed in the direction of greater energy management and performance capability at lower cost.
3. Self-optimizing local systems such as micro-grids will become more economically viable, technically feasible and desirable. The possibility of local resiliency via islanding in response to system disturbances will be a significant driving factor.

4. The number and diversity of DER will continue to grow, and will include new types of DER that have not yet appeared in the marketplace.
5. All of the above will require considerable re-thinking of distribution system operation, planning and architecture over the next few years. Today's distribution systems and operating paradigms were not designed for multi-directional energy flows and the coordination of large numbers of diverse independent resources.
6. The expansion of DER will reduce MWh volumes on the transmission grid as well as kWh retail sales on the distribution system, affecting physical phenomena such as patterns of congestion as well as financial aspects such as traditional utility revenue sources.

III. RESPONSES TO QUESTIONS

1 What specific criteria should the Commission consider to guide the IOUs' development of DRPs, including what characteristics, requirements and specifications are necessary to enable a distribution grid that is at once reliable, safe, resilient, cost-efficient, open to distributed energy resources, and enables the achievement of California's energy and climate goals?

Response: For the near term the IOUs' plans should focus primarily on identifying locations that can accommodate significant DER development without major upgrades to distribution infrastructure and whose other characteristics – such as renewable energy resources and customer adoption potential – offer attractive opportunities for DER developers. The results of this assessment should feed into the CPUC's annual formulation of the RPS portfolios used by the CAISO for transmission planning and DG deliverability. For the longer term, as suggested in the more comprehensive vision of the More Than Smart paper, the IOUs should consider enhancements to distribution operation and planning to address all the complexities created by multi-directional energy flows from large numbers of diverse DER.

2 What specific elements must a DRP include to demonstrate compliance with the statutory requirements for the plan adopted in AB 327?

No response.

3 What specific criteria should be considered in the development of a calculation methodology for optimal locations of DERs?

Response: In addition to factors related to the capability of the existing distribution system and the DER development potential in each area, optimal DER location should be informed by resource deliverability and effectiveness, especially for those DER that wish to provide energy and capacity services to load-serving entities and the CAISO. The deliverability criterion captures the ability of a supply resource to generate energy under peak load conditions without violating transmission constraints or causing the curtailment of other deliverable resources. On this basis the resource can qualify to provide resource adequacy capacity. The CAISO annually determines distributed generation deliverability available at specific transmission-distribution interfaces identified for study in the CPUC RPS portfolios.

The expansion of DER adds a new complication to assessing deliverability, even though only a portion of the DER may be seeking to obtain deliverability status for resource adequacy. The issue is that the CAISO's deliverability study process assumes peak load conditions to test whether all the deliverable generation in an electrical area can be dispatched without overloading any transmission facilities. The results of that test enable the CAISO to award deliverability status and net qualifying capacity to specific resources. If the installation of non-resource adequacy DER (e.g., residential rooftop solar) significantly reduces the peak load in an area, the deliverability assessment may find that some portion of the generation that was previously deliverable is no longer deliverable, which may in turn reduce the amount of eligible resource adequacy capacity for the system. This impact should be included in the consideration of optimal locations for DER.

The effectiveness criterion determines how effective a supply resource is, due to its location, for resolving transmission constraints in the local capacity areas.

4 What specific values should be considered in the development of a locational value of DER calculus? What is optimal means of compensating DERs for this value?

Response: From the CAISO perspective, the characteristics of deliverability and effectiveness as defined earlier should be included in the calculation of the locational

value of a resource. Deliverability is a threshold requirement for a resource to provide resource adequacy capacity and earn the associated revenue stream.

Other important dimensions of locational value are the quantity and in-service dates of proposed DER. Typically a locational need for DER will be defined in terms of a quantity of DER capacity needed and a date by which it is needed. The CAISO determines these kinds of needs through its transmission planning process (TPP) and its locational capacity requirements (LCR) studies. If DER projects are proposed to meet these types of needs, DER capacity in excess of the calculated need may have very little incremental value. Moreover, if the CAISO's planning studies indicate a need for a reliability upgrade to the transmission system by a certain date in the future, DER projects that would commence operation later may have very little value compared to projects that can meet the target date.

5 What specific considerations and methods should be considered to support the integration of DERs into IOU distribution planning and operations?

Response: Most developers of DER today are very interested in having their projects provide resource adequacy capacity and participate in the CAISO markets. As the amount and diversity of such DER increase, the IOU distribution system will need to consider how to coordinate the responses of these resources to CAISO dispatch instructions, so as to maintain reliable distribution system operation while enabling the resources to provide the response needed and expected by the CAISO. This coordination is essential to maintaining reliable T-D interface flows in the high-DER electric system, and should constitute a central inquiry within the longer-term program outlined in the More Than Smart paper.

6 What specific distribution planning and operations methods should be considered to support the provision of distribution reliability services by DERs?

Response: Up to now most thinking in the industry regarding the impacts of DER, particularly renewable distribution generation, has viewed such resources as obtaining benefits from and imposing problematic operational impacts on the distribution system. While this view is not without empirical basis, it should not limit the consideration of future possibilities. In particular, to support the state's goals for renewable distributed energy resources, it will be important for the IOUs to distinguish between those DER

whose performance capabilities limit their ability to provide services to support distribution system operation and those DER that are capable of providing such support. As such a distinction becomes part of the operating and planning strategies for the distribution system, and DER that can provide reliability services are compensated for such services, the structure of financial incentives can shift towards encouraging developers to build these capabilities into their projects and refrain from developing projects that are more passive and impose volatility on the distribution system. Thus, this proceeding's openness to considering DER provision of distribution reliability services is a crucial step towards incentivizing the development of DER types and configurations that have minimal adverse impacts on system operation.

7 What types of benefits should be considered when quantifying the value of DER integration in distribution system planning and operations?

Response: Two main categories of benefits should be considered. The first is the more traditional category of benefits associated with the provision of renewable energy and local capacity. These benefits contribute to meeting local resource adequacy needs and, depending on the DER's performance characteristics, flexible capacity as well. The same benefits may also allow the avoidance or deferral of distribution or transmission infrastructure upgrades. The second category of benefits, which will require further effort to define more precisely, involves the ability of some types of DER, depending on their performance characteristics, to provide distribution reliability services. The CAISO believes that although both categories of benefits are important for the transition to a high-DER electric system, the first category may be more attainable in the time frame of the DRP proposals; whereas, the second category will likely take longer because it will require, among other things, some new commercial and regulatory framework elements.

8 What criteria and inputs should be considered in the development of scenarios and/or guidelines to test the specific DER integration strategies proposed in the DRPs?

Response: Scenarios should reflect the full range of potential operating conditions. If the set of scenarios studied is too narrow, it may turn out that far more curtailment of renewable DER will be needed than was anticipated, due to frequent occurrence of conditions outside the range of what was studied.

9 What types of data and level of data access should be considered as part of the DRP?

Response: From an operations perspective, for the local distribution area circuits below each transmission-distribution interface point (substation or P-node), the CAISO would need to know both the peak and the profiles of gross load in that area as well as the corresponding net load values at the substation after accounting for the supply provided by DER. As the volume and diversity of DER in a given area increase, the energy flows across the interface will tend to become more variable and may even change direction at times – *i.e.*, from net flow of energy off the transmission grid to net flow onto the grid, and vice versa. Thus, it will be crucial for the CAISO and UDCs to develop both forecasts and real-time data of gross load and DER output that offer sufficient accuracy to support reliable grid and market operation.

For system studies, the CAISO will need more detailed information about the mix of load and generation types, so that these can be incorporated into the composite load model, particularly for system dynamic stability and frequency studies.

10 Should the DRPs include specific measures or projects that serve to demonstrate how specific types of DER can be integrated into distribution planning and operation? If so, what are some examples that IOUs should consider?

No response.

11 What considerations should the Commission take into account when defining how the DRPs should be monitored over time?

Response: An important consideration is whether the development of committed new infrastructure and DER projects is proceeding in a timely fashion to ensure that the needed facilities and resources will be operational by the time they are needed. The CAISO has often articulated this concern in the context of transmission planning when considering the substitution of preferred non-transmission alternatives for a transmission upgrade that will be needed at a future date to maintain reliable system operation. If the development of the preferred alternative is stalled or delayed for some reason, there must be sufficient time to identify and pursue a fallback solution to meet the projected operational need. The CAISO expects that analogous considerations should be taken into account in monitoring DRPs over time.

12 What principles should the Commission consider in setting criteria to govern the review and approval of the DRPs?

Response:

Information sufficiency: As an example, there should be sufficient information for a DER developer to make a reasonable assessment of the services needed, the magnitude and timing of any needs to be resolved, development limitations/restrictions, and megawatt size limitations.

Transparency: There should be sufficient publicly available data and analysis to draw reasonable conclusions about the data and facts presented concerning DER needs, value, and requirements, including clear explanations of assumptions made in reaching conclusions.

Collaboration: There should be stakeholder input early and often in the process, with stakeholders invited to vet preliminary DER planning assumptions and results.

Coordination: There should be clear coordination and integration of the DRP with other related and inter-dependent planning exercises conducted by the CPUC, CEC, and CAISO.

13 Should the DRPs include discussion of how ownership of the distribution may evolve as DERs start to provide distribution reliability services? If so, briefly discuss those areas where utility, customer and third party ownership are reasonable?

No response.

14 What specific concerns around safety should be addressed in the DRPs?

No response.

15 What, if any, further actions, should the Commission consider to comply with Section 769 and to establish policy and performance guidelines that enable electric utilities to develop and implement DRPs? Attachment 1 to this order is a complete copy of AB 327 as enacted.

No response.

16 Appendix B to this rulemaking is a white paper that articulates one potential set of criteria that could govern the IOUs DRPs. Please review the attached paper and answer the following questions:

- **Integrated Grid Framework: the paper opens by presenting an 'Integrated Grid Framework,' what additions or modifications would you suggest be made to this framework?**

No response.

- **Integrated Distribution Planning: what, if any, additions or modifications would you suggest to the Integrated Distribution Planning section of this paper?**

Response: The CAISO suggests augmenting the discussion in this section by identifying the need to align periodic distribution planning processes by the UDCs with the existing structural alignment of the CEC's biennial IEPR demand forecast, the CAISO's annual transmission planning process (TPP), and the Commission's biennial LTPP proceeding. During 2013, a joint-agency staff team from the CEC, CPUC and CAISO developed a structural process alignment of these three activities which are central for electricity planning and procurement. The alignment uses a swim-lane approach to indicate normal time frames for key activities (such as studies, workshops, hearings, etc.), flows of information or other key inputs between the processes, and CEC, CPUC and CAISO Board of Governors decisions. Because these processes are now functioning with established regularity, it is appropriate to align any new periodic distribution planning activities with them. This is even more important because of the role of DER development in all three. In the case of the IEPR demand forecast, projections of DER development have significant impacts on both the economic-demographic forecast of demand (i.e., for behind-the-meter DER that are categorized as "load modifiers") and the expected future supply fleet (i.e., for market-participating DER). Similarly, projections of DER development will affect both procurement decisions in the LTPP and transmission upgrade decisions in the TPP.

- **Distribution System Design-Build: what, if any, additions or modifications would you suggest to the Distribution System Design-Build section of this paper?**

Response: With respect to this section of the More Than Smart paper, the CAISO offers some of the logic that went into the 2010 redesign of its transmission planning process, which could serve to reinforce certain planning concepts articulated in the paper. In particular, the idea of using multiple scenarios of DER development as a way to identify "least regrets" grid infrastructure investments when faced with the dilemma of the need

to enhance grid capabilities fairly quickly under conditions of uncertainty about the pace and pattern of DER development over the next several years. In 2009, the CAISO realized that a major driver – perhaps the primary driver – of need for new transmission would come from the dramatic turnover of the supply fleet in response to state policy initiatives, primarily the renewable portfolio standard (RPS) and the once-through-cooling (OTC) mandate. The CAISO interconnection queue was flooded with renewable generation projects adding up to nearly five times the amount of capacity needed to meet the RPS, while the state's renewable energy transmission initiative (RETI) identified dozens of potential areas for renewable generation development, most of which lacked transmission to bring the energy to the load centers. The implication was significantly costly new transmission would be needed, but with no way to decide which transmission to build, which areas to connect to the system.

The solution to the problem involved a major overhaul of the TPP, including a crucial collaborative role with the CPUC. Under the revised TPP the CPUC develops RPS portfolios each year, one of which reflects the most likely trajectory of generation development to meet the RPS based on a number of variables including actual project development and procurement activity, and the others reflect variations such as higher levels of imports or distributed generation. The CAISO studies then identify transmission needs for each of the scenarios, and from those needs the CAISO singles out "least regrets" transmission upgrades that will be needed under more than one scenario, so as to minimize the risk of stranded investment.

Another feature of the CAISO's revised TPP is that it provides a clearly defined and structured approach for stakeholder input, including opportunities to offer input to and comment on draft planning assumptions, suggestions for transmission upgrades to address identified needs, review and comment on the CAISO's planning study results, and review and comment on a draft of the CAISO's annual comprehensive transmission plan.

The CAISO suggests that, as the Commission and the UDCs move forward with this part of the More Than Smart program to implement a periodic distribution planning process, some of the concepts, lessons learned and stakeholder engagement approaches of the revised TPP may be useful models to consider.

- **Integrated Distribution System Operations: what, if any, additions or modifications would you suggest to the Integrated Distribution System Operations section of this paper?**

Response: This section of the paper introduces the idea of a "minimal DSO," which would have certain limited responsibilities related to maintaining safe and reliable operation of the distribution system under a high-DER paradigm that reflects more or less a continuation the current trajectory. In other words, the minimal DSO is the DSO that is needed under the assumption that most DER above a relatively low size threshold (on the order of 100-200 kW capacity, for example, or aggregations that add up to that size) will participate in the wholesale market and be subject to centralized CAISO dispatch. While this may be the most likely and perhaps even the most desirable future paradigm, it would be premature and risky to assume that that's how the industry will evolve with high penetration of diverse DER and to develop all the details of the More Than Smart program on that assumption.

An earlier section of the paper discusses the importance of using scenarios to consider potential future distribution infrastructure investments, so as to identify "least regrets" investments that would be needed under multiple scenarios, thereby minimizing the risk of stranded infrastructure investment. Similarly, in considering the DSO of the future the Commission should consider a reasonable spectrum of possible DSO models. These models would be defined, for the most part by (1) the extent to which DER participate in the wholesale market and the CAISO dispatch; (2) the means by which they participate; and (3) the implications of these factors for the optimal allocation of roles and responsibilities between the distribution and transmission operators (i.e., the UDC and the CAISO, respectively) especially with regard to the distribution-transmission interfaces (i.e., substations or P-nodes). The range of reasonable DSO models could be captured by three to five scenarios, ranging from the minimal DSO at one end, to what might be called a "total DSO" at the other end, which would essentially aggregate and coordinate the activity of all customers and DER within each local distribution area and appear to the transmission operator as a single resource at the transmission-distribution substation. Two or three intermediate scenarios would capture qualitatively meaningful distinctions. Then each of these scenarios should be evaluated on numerous criteria, including, but not

limited to, their ability to further the state's energy and environmental goals, operational reliability and efficiency, support for customer choice and innovation.

- **Integration of DER into Operations: what, if any, additions or modifications would you suggest to the Integration of DER into Operations section of this paper?**

No response.

- **Integrated Grid Roadmap: what, if any, additions or modifications would you suggest to the Integrated Grid Roadmap section of this paper?**

Response: The Integrated Grid Roadmap is a reasonable conceptual overview of the needed process to evolve distribution system operations and planning for a future electric system that is highly decentralized and features large amounts of diverse DER, and to update the roles and responsibilities of distribution and transmission operators on their sides of the interfaces and to coordinate the planning of both systems. However, the roadmap offers very little detail. Although the preceding sections of the paper describe much of what needs to be done, the next iteration of the roadmap needs to translate the necessary activities into more of a work plan, with specific work efforts on a common time line, with designations of milestones and linkages and inter-dependencies between the parallel efforts. The More Than Smart paper suggests that the entire effort will take at least three years, which may be a reasonable estimate. But given the pace of change in the DER arena – particularly the rapidly increasing capabilities and functionalities and falling costs of the technologies, combined with increasing consumer desires to have greater choice and flexibility in how they obtain and use energy, and the rising attractiveness of local resiliency (*e.g.*, micro-grids) as a strategy to reduce vulnerability to system disturbances of all kinds – and the impacts of all these changes on electric system operation – the CAISO suggests that the Commission make it a priority. In parallel to providing guidance to the IOUs for their AB 327 filings, the CPUC should turn the Integrated Grid Roadmap into a more concrete work plan and consider how to engage industry participants and stakeholders in addressing the open questions and designing the details of the 21st century distribution system.

IV. CONCLUSION

The CAISO appreciates the opportunity to submit these comments and looks forward to working with the Commission and stakeholders to address the important near-term and longer range DRP issues identified in the OIR.

Respectfully submitted,

By: *<u>/s/ Judith B. Sanders</u>*

Roger E. Collanton
General Counsel
Anna A. McKenna
Assistant General Counsel
Judith B. Sanders
Senior Counsel
Jordan Pinjuv
Counsel
California Independent System
Operator Corporation
250 Outcropping Way
Folsom, CA 95630
T – (916) 608-7007
F – (916) 608-7222
jsanders@caiso.com

Attorneys for the California Independent System
Operator Corporation

September 5, 2014