Rulemaking	13-09-011
Exhibit No.:	
Witness:	Jeremy Laundergan

Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements	Rulemaking 13-09-011

REBUTTAL TESTIMONY OF JEREMY LAUNDERGAN ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements	Rulemaking 13-09-011

REBUTTAL TESTIMONY OF JEREMY LAUNDERGAN ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

Q. What is your name and by whom are you employed?

A. My name is Jeremy Laundergan. I am employed by EnerNex LLC, 620 Mabry Hood Road, Suite 300, Knoxville, Tennessee as Director of Utility Services Consulting.

Q. Please briefly describe your employment and educational background.

A. I hold a Bachelor's degree in Industrial Engineering from University of Minnesota Duluth and a Master of Science in Engineering Management from California State University Long Beach. I also hold certifications in Project Management from University of California Irvine and the Project Management Institute, Information Technology Infrastructure Library from ISEB/EXIN and Engineering Management from California Institute of Technology. Prior to working for EnerNex, I was a Senior Project Manager with Southern California Edison (SCE) and led their Emerging Markets and Technology projects for Demand Response.

Q. What are your job responsibilities?

A. I work with utility, regulator, government agencies, municipalities and balancing authority clients on a variety of projects including the strategic, tactical, policy, business requirements, business processes, and project implementation aspects of Demand Side Management (DSM) and Grid Modernization projects to evaluate cost effective alternatives to meet business challenges. One of these projects was EnerNex's contract to the National Institute of Standards and Technology (NIST) to be the administrator of the Smart Grid Interoperability Panel (SGIP) which worked with a broad spectrum of stakeholders to achieve interoperability of smart grid devices and systems. Under the SGIP contract, I served as the Technical Champion for the Priority Action Plan investigating Wholesale DR Communication Protocols.

Q. Have you previously provided testimony about demand response in this proceeding or in other Commission dockets?

A. Yes. In my role as a Project Manager at SCE, I assisted in the preparation of testimony related to DR in both the Advanced Metering Infrastructure proceeding as well as various demand response proceedings from 2006 through the first quarter of 2011. This included reports to the CPUC on the 2009 SCE Participating Load Pilot[1] as well as the A.08-06-001-Report on the Transition of Southern California Edison Company Demand Response Programs into Market Redesign & Technology Update (MRTU)[2]. However, I was not the witness presenting the testimony in the related evidentiary proceedings.

Q. What is the purpose of your rebuttal testimony?

A. I was asked to assist the CAISO in addressing issues related to the integration costs, benefits and procedures associated with integrating supply-side demand response

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[1] 2009 SCE Participating Load Pilot Feasibility Report: http://on.sce.com/1ueEZkh

[2] A.08-06-001-Report on the Transition of Southern California Edison Company (U 338-E) Demand Response Programs into Market Redesign & Technology Update (MRTU), February 4, 2011: http://on.sce.com/RchRn9

participation into the CAISO market and to respond to opening testimony submitted by parties to this proceeding on this topic. My rebuttal testimony focuses on the opening testimony sponsored by PG&E; in particular witnesses Alex Papalexopoulos, Stephen Kung and Spence Gerber.

I. INTEGRATING SUPPLY-SIDE DEMAND RESPONSE INTO THE CAISO MARKET- OVERVIEW

Q. In PG&E Vol. 1 Page 3-2 item A, Stephen Kung states that there are opportunities to reduce the costs and complexity of integrating DR resources as Supply Resource DR, primarily by modifying the CAISO's processes. Do you agree?

A. Yes, there are opportunities to reduce cost and complexity related to integrating DR as a supply resource and CAISO is committed to continuing engagement with stakeholders to identify areas for improvement and investigate viable alternative approaches. Examples of recent changes that CAISO has implemented or is in the process of implementing in response to stakeholder feedback are described in the responses below.

Q. PG&E Table 3-2 on Page 3-14 contains a summary of costs related to PG&E PDR1 implementation. Do you have any observations about the contents of this table?

A. Yes, Table 3-2 illustrates upfront capital costs as well as expenses related to enabling the PDR1 functionality. Similar to other investments, like the costs to build a new generation resource, there is an upfront capital investment needed with the expectation that those costs are amortized over time and subsequent benefits are utilized to justify the initial investment. The Commission must realize that the IOUs are investing in new demand response opportunities and capabilities that they do not currently have, but, if deemed reasonable and prudent, are necessary expenditures to develop the next generation of supply-side demand response. CAISO understands that there are two additional capital investment phases being considered with PDR2 functionality building upon PDR1 and Rule 24 direct participation functionality building upon PDR2. It also is worth noting that after initial project startup, the expense costs seem to drop off significantly.

TABLE 3-2
PACIFIC GAS AND ELECTRIC COMPANY
PDR1 COSTS RECOVERED THROUGH MRTU

Line No.	Operational Period	PDR Business Related (Expense)	PDR Information Technology Related (Capital)	MRTU Application
1	7/30/2008 – 12/31/2009	$196,109	–	A.09-06-001
2	1/1/2010 – 12/31/2010	181,725	$7,355,000	A.12-01-014
3	1/1/2011 – 12/31/2011	52,000	8,297,000	A.12-04-009
4	Totals	$429,834	$15,652,000	
5	Grand Total		$16,081,834	

Q. Starting at PG&E Vol. 2 page A-4, Dr. Papalexopoulos states that supply-side demand response participation in the CAISO market exposes resource owners to certain risks, and that bidding resources into an electricity market requires considerable foresight, sophistication and knowledge on the part of consumers. Do you agree with these assertions?

A. No, I do not. With a few exceptions, the end use customer will be participating in programs offered by a Demand Response Provider (DRP). In this scenario, the DRP is the entity that will require considerable foresight, sophistication and knowledge of the energy market. From the customer perspective, their participation is dependent on their willingness to participate in a program with the defined compensation and obligations outlined in their agreement with the DRP, which may include the DRP or customer installing certain enabling technology. As described later in my testimony, enabling technology, such as OpenADR 2.0, continues to evolve and can attain a level of autonomous "set and forget" participation by the customer. The agreement between the DRP and the end use customer will determine the level of risk exposure for the participating end use customer. The bilateral contractual provisions may or may not expose resource owners to market participation risks.

Q. Does market participation require substantial customer input and interaction which may not be supported by the economic value of the bidding transaction, as Dr. Papalexopoulos cautions?

A. Not necessarily. The bid price for a DR resource is determined by the demand response provider (DRP) as submitted through their Scheduling Coordinator. The bid price would logically be derived based on the cost to manage DR participation in the market including customer incentive payments and program management costs as well as amortized enabling technology investments and back office systems. Therefore, the economic incentive for customer participation would be included in the bid price for that DR resource. Additionally, the bid price is the minimum compensation for the dispatch of that resource (less any applicable CAISO charges). In addition to the potential market payments, there also is the LSE's Resource Adequacy (RA) capacity payment credit which adds to the economic value of the resource.

Q. Dr. Papalexopoulos states that market participation requires an in-depth knowledge of the customer's electricity demand as well as a baseline methodology that accurately measures the customer's performance. Is this consistent with your understanding?

A. Not exactly. It is my understanding that the assessment of a customer's DR capability is already incorporated into the process for participation in current DR programs. For example, Air Conditioning cycling programs estimate demand reduction by the tonnage of air conditioning and there are existing models to estimate the amount of curtailable load based on outdoor temperature. Current Aggregator Managed Portfolio and 3rd party providers for the Capacity Bidding Program must also have knowledge about the customer's DR potential in order to successfully fulfill their performance obligations under their contract with the IOU.

However, the performance and precision needed to successfully migrate retail DR programs to supply-side demand response participating in the CAISO market may require an evolution of existing capabilities. The DR enabling programs such as Technology Incentive and Automated Demand Response (AutoDR) Incentive compensate customers between $125 per kilowatt (kW) and $400 per kW of DR load reduction (dispatchable load). These incentives can be used to implement the capability needed to perform as a supply resource. Specifically, this level of capability was included within DR messaging protocols like OpenADR 2.0 Profile B which was released in 2013 and was balloted into the Smart Grid Interoperability Panel (SGIP) Catalog of Standards (CoS) in March 2014. I understand that the California IOUs are now requiring OpenADR 2.0 for all new AutoDR program reservations, but it will take time for AutoDR 2.0 installations to be completed and the more advanced features of OpenADR 2.0 Profile B to be enabled, integrated into DR programs, and adopted by customers to achieve the full envisioned functionality.

Evaluation of customer DR potential and related DR settlements and baselines will further utilize the smart metering solutions already deployed by PG&E, SCE and SDG&E. The current PDR baseline approach attempts to align with the 10 in 10 baseline methodology adopted by the CPUC for DR performance estimation. Fifteen minute interval meter data is currently being collected for non-residential customers and hourly interval data is being collected for residential customers. Furthermore, the CAISO is working through a Metering and Telemetry stakeholder process to determine the most cost and technically effective way to utilize existing metering functionality to meet baseline, metering and telemetry requirements.

Q. Do you agree that the implementation process for full demand response participation in the CAISO market is complex because the wholesale market was mostly designed and implemented for generation-like resources like Participating Load and Aggregated Participating Load (Papalexopoulos testimony at A-5)?

A. No. While the MRTU construct was designed to facilitate efficient utilization and optimization of generation resources, in 2009 the CAISO was directed by the Federal Energy Regulatory Commission to enable direct participation by demand response resources. An extensive stakeholder engagement followed resulting in the Proxy Demand Resource (PDR) market construct which was specifically developed to enable direct participation by supply-side demand response. There are implementation challenges that the CAISO and stakeholders are addressing, in stakeholder discussions as well as through this proceeding, with respect to bringing demand response programs into the market.

An evolution of DR capability beyond existing DR programs, with more refined command and control functionality, will be required to achieve greater levels of supply-side DR participation – especially demand response that can offer Ancillary Services, for example. However, this evolution is logical and likely inevitable as more sophisticated and standardized capabilities such as those enabled by OpenADR 2.0 are adopted by the industry. The number of OpenADR certified commercial-off-the-shelf products continues to grow[3] and non-residential DR programs are already migrating to this standard.

II. SUPPLY-SIDE RESOURCE INTEGRATION ISSUES

Q. Starting on page A-10, Dr. Papalexopoulos describes changes that could be made to the CAISO's rules and processes to facilitate participation in the market. Do you have responses to his recommendations?

A. Yes, I do. My responses are set forth below.

Aggregation Across Sub-LAPs

PG&E, as well as other DRPs, have argued that DR resources should be aggregated across sub-LAPs because otherwise it is impossible to aggregate customers into the minimum 100 kW resource for market participation.

In essence, dispatching a resource with service accounts across sub-LAPs may result in increased or additional congestion that may not have existed prior to the dispatch response. Dr. Papalexopoulos recognizes this but maintains that this congestion will be minimal. Dr. Kristov addresses this issue in more detail in his testimony and provides further support for the CAISO's existing tariff requirement that permits customer aggregation for DR within a sub-LAP but not across multiple sub-LAPs. As he explains, because of the need to most cost-effectively dispatch resources

[3] http://www.openadr.org/certified-products

to manage congestion and the increased expectation of demand response as part of the resource mix, the CAISO will maintain the sub-LAP construct for aggregate participation but is committed to reviewing the sub-LAP definitions and providing these results to stakeholders.

Some current DR programs are comprised of customers aggregated across the entire IOU service territory (D-LAP) and are dispatched by the IOU at this level. The CAISO recognizes that if these resources cannot be dispatched at the D-LAP level through the CAISO market, the IOU will either need to categorize them as load-modifying resources or develop the capability to disaggregate them to the sub-LAP level for CAISO market participation. For the latter option, there are two types of IOU costs that will be required to enable sub-LAP, pNode or APNode dispatch of DR resources that are currently dispatched at the D-LAP. The first is customer enrollment and participation in retail DR programs within the sub-LAP to meet the minimum 0.1 MW threshold to participate as a supply-side resource. The other is modification of the existing IOU DR dispatch systems to enable dispatch by sub-LAP, pNode or APNode.

With respect to enrolling customers in retail DR programs within the sub-LAP, the mechanics of dividing DR resources to align with CAISO sub-LAPs is fairly straightforward. Within the PDR construct, a resource is comprised of registrations and registrations are comprised of locations. The customer's geographic location is known and the CAISO sub-LAPs align with the transmission system configuration. Therefore, if the IOU knows which A-Bank substation the customer is connected to, the sub-LAP identification should be possible. In fact, in 2013 PG&E stated "Currently, each day PG&E and the other IOUs provide the CAISO the DR they plan to dispatch that day, by sub-Load Aggregation Point (sub-LAP)" in their comments at the Demand Response and Energy Efficiency Roadmap and Workshop[4]. It is then a matter of customer recruitment and program growth to aggregate customers to achieve the minimum 100 kW for participation.

With respect to changes to the IOU dispatch systems, some existing DR dispatch systems were designed and built for system wide dispatch in response to a reliability/emergency event. These systems would need to be modified in order to enable DR dispatch by sub-LAP or by pNode or APNode within the sub-LAP. A common approach for this is to enable customer enrollment groups with one of the group attributes denoting the customer's sub-LAP, pNode or APNode. The level of cost or investment required to achieve regional rather than territory wide dispatch of a DR program will depend upon the sophistication of the DRP's dispatch system. Some DR dispatch systems have already been updated accordingly, so there are not likely to be additional costs.

Customer Registration

Dr. Papalexopoulos suggests that the CAISO permit a "one to many" registration process that would allow customers to be switched within an aggregation without resubmitting the entire registration. CAISO understands the challenges of registration for aggregated DR resources that are comprised of multiple customers (hundreds and thousands). The current process requires a registration to be updated when a customer location enrolls in a resource registration or when a customer leaves a resource

[4] Comments of Pacific Gas & Electric Company, CAISO Demand Response and Energy Efficiency Roadmap and Workshop, May 21, 2013: http://www.energy.ca.gov/2013_energypolicy/documents/2013-06-17_workshop/caiso_dr_workshop_materials/PGE-CommentsDemandResponse-EnergyEfficiencyRoadmapWorkshop.pdf

registration. The demand response system requires manual entry of individual service accounts for registration. The CAISO agrees that this is not feasible for DRPs with large numbers of service accounts that participate in DR programs because manual entry is time-intensive and carries significant risk of entry errors. The ISO's business process manual also requires several validations to be performed that are not easily done manually. The ISO agrees that a technology solution is required. CAISO will work with stakeholders to review the resource registration process to consider the challenge of dynamic DRP customer program enrollment. This solution is underway and will be available in Q4 2014. Technical interface specifications will be available by July to support interface development by participants.

Dr. Papalexopoulos is also concerned that resource bidding into the CAISO market is "all or nothing" and that individual resources are not able to bid in a specific event. However, the total resource capability for a registration does not need to be bid. Therefore, bids can be adjusted based on the expected amount of DR available. The ability to both forecast the amount of DR that can be delivered and the capability to perform to specific dispatch instructions will evolve over time. Additionally, large aggregations tend to minimize the effects of individual participants underperformance because other customers may be over-performing. The ISO has provided direction for modeling PDR to reflect this resource constraint. At this time, the CAISO does not intend to review or revise this requirement and we encourage future DR program development to include partial dispatch ability.

10 MW Minimum Load Drop

Dr. Papalexopoulos recommends that the CAISO revisit the .10 MW (100 kW) minimum load drop requirement. He states that, although DR resources can be aggregated, the resources may be across sub-LAPs, which is not allowed under current rules. CAISO acknowledges that there may be a near-term challenge for starting up DR programs to participate in the CAISO market with enrolling enough customers to achieve the minimum load requirements of 0.1 MW. Regarding the potential to achieve customer enrollments in order to meet the 0.1 MW minimum requirement, a comparison with current programs provides some insight. As reported in the PG&E Demand Response July 26, 2011 Cost-Effectiveness spreadsheets[5], the "Load Impacts 1 in 2 Years (MW)" line item reported Baseline Interruptible Program between 197 and 225 MW, Capacity Bidding Program at 24.4 MW and Demand Bidding between 5.4 and 6.2 MW. Assuming an equal distribution between the sixteen PG&E sub-LAPs, each of these programs could reach the minimum 0.1 MW participation threshold.

Ancillary Services Requirements and Certification

Dr. Papalexopoulos recommends that the CAISO introduce a resource option in the Master File, directly applicable to supply resource DR, which treats the bid in MW quantity as the maximum available MW quantity. The master file reflects the demand reduction documented during the resource certification. The resource can then bid the amount of DR expected to be available within the range of the master file certification

[5] PG&E Demand Response July 26, 2011 Cost-Effectiveness spreadsheets: http://www.cpuc.ca.gov/NR/rdonlyres/728FAD3B-E6F2-4300-8E69-859D36327E4A/0/PGE_DRReportingTemplate_approxDBP_Default.xls

limit and if the bid is accepted, any related dispatch would reference the amount bid rather than the full master file amount.

He also suggests that DRPs be given the flexibility to determine the baseline approach that fits their own operating schedule profile. As part of their Proxy Demand Resource pilot and Report on the Transition of SCE DR Programs into MRTU, SCE did an extensive examination of baseline methodologies[6]. The current PDR baseline approach attempts to align with the 10 in 10 baseline methodology adopted by the CPUC for DR performance estimation. However, as the SCE report points out, there is room for improvement in the accuracy of baselines. It is in CAISO's best interest to utilize baselines that accurately reflect the resource performance. The CAISO is open to receiving suggestions and working with stakeholders to assess baseline estimation of performance relative to the observable load curve and introduce alternative baseline calculations.

Metering and Telemetry

Starting at page A-18, Dr. Papalexopoulos makes several suggestions with respect to metering and telemetry. The CAISO has made progress in simplifying the telemetry requirements.

- **Relax the requirements for the use of dedicated leased lines, such as the Energy Communications Network (ECN).**

CAISO is now offering current and future market participants the ability to connect to the ECN without the need for a dedicated lease line. The new ECN "indirect" (Internet access via AT&T ANIRA solution) option is less costly than the ECN direct

[6] Report on the Transition of Southern California Edison Company (U 338-E) Demand Response Programs into Market Redesign & Technology Update (MRTU), February 4, 2014: http://www3.sce.com/sscc/law/dis/dbattach3e.nsf/0/0CB693A87C9BBD838825782D0082C428/$FILE/A.08-06-001_Report+on+the+Transition+of+SCE+DR+Programs+into+MRTU.pdf

(AT&T leased line T1) option. Initial details regarding the pricing for this option are outlined in the table below.

Table 1 AT&T ECN Connection Options and Related Costs

ECN Cost		Minimum	Maximum
Access Costs (required):			
• **Installation (non-recurring)**	Option 1) ECN direct (AT&T leased line T1) option with a minimum of one year service.	$0	
	Option 2) ECN "indirect" (Internet access via AT&T ANIRA solution) option[7]		$260
• **Monthly Cost (recurring)**	Option 1) ECN Direct (per month)		$225
	Option 2) ECN "indirect" (per month)	$100 (plus the cost of customer's broadband connection)	
Hardware Cost (optional):	Equipment and installation (non-recurring)	$1,900	$3,100
Management Cost (optional):	Management and maintenance services (recurring)	$152	$190

- **Relax the restrictions requiring the telemetry gateways be sited within the same sub-LAP as the telemetered resources.**

CAISO recently implemented this change enabling a single remote intelligent gateway (RIG) as the telemetry conduit for all DR resources under a Scheduling Coordinator ID (SCID) that require telemetry including DR resources residing in different sub-LAPs.

[7] http://www.business.att.com/content/productbrochures/ANIRA_pb.pdf

- **Increase the threshold of 10 MW for telemetry for resource aggregations.**

  The ISO is open to reviewing this threshold requirement for telemetry for resource aggregations. My understanding is that the CAISO is performing a gap analysis of requirements for demand response participation including the aggregation threshold amount. However, the CAISO suggests that DRPs may also want to consider aggregating resources to keep below the threshold that triggers the telemetry requirement.

- **Relax the communications protocols and allow ICCP (Inter-control Center Communications Protocol) as an alternative communication protocol for telemetry.**

  ICCP as an option is currently being proposed and CAISO is working through the details on how it will be offered. BPM changes will be required to make it as an offering for DRPs. However, ICCP will require an ECN connection and would not be available if utilizing the new ECN "indirect" option.

III. TRANSITIONING EXISTING PROGRAMS TO PARTICIPATION IN THE CAISO MARKET

Q. In Appendix B, Spence Gerber provides testimony related to the cost and complexity of transitioning existing DR programs in order to be compatible CAISO market participation. What is your general recommendation with respect to transitioning existing programs to the wholesale market?

A. The emphasis of the PG&E testimony has focused on compatibility of existing DR programs for transition into CAISO market participating resources. CAISO does not have insight into the back office and program management costs at the core of the PG&E comments and appreciates the challenges and costs of systems upgrades and modifications. However, I would argue that developing new DR program options specifically designed for CAISO market participation such as day-ahead energy or real time ancillary service would be a more effective approach. As I discussed earlier in my testimony, new DR technologies and protocols such as OpenADR 2.0 Profile B were specifically designed to be compatible with wholesale markets through the collaboration process of Smart Grid Interoperability Panel (SGIP) Priority Action Plan (PAP) 19[8] and OpenADR Profiles A and B were adopted into the SGIP Catalog of Standards in March 2014[9]. Designing new DR programs utilizing market compatible messaging and response protocols with associated technologies will take time to build customer participation. The related technologies such as DR capable building controls are already specified in California Energy Commission (CEC) Title 24 Building Energy Efficiency Standards[10] as well as incentivized by CPUC approved Technology Incentive (TI) and Automated Demand Response (AutoDR) with medium to large commercial customers compensation between $125 per kilowatt (kW) and $400 per kW of DR load reduction (dispatchable load). Title 24 complemented by TI and AutoDR will build customer capability to participate in CAISO compatible DR programs.

Q. How would developing new CAISO compatible DR programs affect existing DR program participants?

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[8] SGIP PAP19 Wholesale Demand Response (DR) Communication Protocol artifacts and recommendations http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/PAP19Closeout

[9] The SGIP Catalog of Standards is a compendium of standards and practices considered to be relevant for the development and deployment of a robust, interoperable, and secure Smart Grid. http://sgip.org/Catalog-of-Standards

[10] 2013 Building Energy Efficiency Standards: Section 130.1 – Indoor Lighting Controls That Shall Be Installed; Section 120.2 – Required Controls For Space-Conditioning Systems; Exception to Section 110.10 – Mandatory Requirements For Solar Ready Buildings; Section 130.3 – Sign Lighting Controls; Section 130.5 – Electrical Power Distribution Systems; Section 140.6 – Prescriptive Requirements For Indoor Lighting; Exception to Section 150.2 – Energy Efficiency Standards For Additions And Alterations In Existing Buildings That Will Be Lowrise Residential Occupancies: http://www.energy.ca.gov/2012publications/CEC-400-2012-004/CEC-400-2012-004-CMF-REV2.pdf

A. The CPUC will determine the extent to continue or modify existing programs. If new CAISO compatible DR programs are developed, customers participating in an existing DR program could be given an option to continue with existing DR programs originally designed to mitigate "emergency" and rolling blackout conditions from 15 years ago with load control or to transition to more relevant programs for today's operational needs that provide customers with more holistic energy management and optimization technologies. The avoided cost of transitioning existing program control systems to be market compatible can then be utilized to refine the existing AutoDR utilization of OpenADR 2.0 Profile A to wholesale market compatible OpenADR 2.0 Profile B.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.