



**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE  
STATE OF CALIFORNIA**

**FILED**  
11-10-16  
04:59 PM

Order Instituting Rulemaking Regarding Policies, )	
Procedures and Rules for Development of )	Rulemaking 14-08-013
Distribution Resources Plans Pursuant to Public )	(Filed August 14, 2014)
Utilities Code Section 769. )	
_____ )	
And Related Matters )	Application 15-07-002
_____ )	Application 15-07-003
<b>(NOT CONSOLIDATED)</b> )	Application 15-07-006
_____ )	
In the Matter of the Application of )	
PacifiCorp (U901E) Setting Forth its )	Application 15-07-005
Distribution Resource Plan Pursuant to )	(Filed July 1, 2015)
Public Utilities Code Section 769. )	
_____ )	
And Related Matters )	Application 15-07-007
_____ )	Application 15-07-008
_____ )	

**LOCATIONAL NET BENEFIT ANALYSIS WORKING GROUP  
FIRST INTERMEDIATE STATUS REPORT ON LONG-TERM REFINEMENTS**

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November 10, 2016

**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)
And Related Matters	)	Application 15-07-002
	)	Application 15-07-003
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<b>(NOT CONSOLIDATED)</b>		
In the Matter of the Application of PacifiCorp (U901E) Setting Forth its Distribution Resource Plan Pursuant to Public Utilities Code Section 769.	)	Application 15-07-005 (Filed July 1, 2015)
And Related Matters	)	Application 15-07-007
	)	Application 15-07-008
	)	

**LOCATIONAL NET BENEFIT ANALYSIS WORKING GROUP  
FIRST INTERMEDIATE STATUS REPORT ON LONG-TERM REFINEMENTS**

Pursuant to the *Assigned Commissioner’s Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B*, dated May 2, 2016, and the *Assigned Commissioner’s Ruling Granting the Joint Motion of San Diego Gas & Electric Company, Southern California Edison Company, and Pacific Gas & Electric Company to Modify Specific Portions of the Assigned Commissioner’s Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B*, dated August 23, 2016, San Diego Gas & Electric Company (U 902-E), on behalf of itself and Southern California Edison Company (U 338-E) and Pacific Gas and Electric Company

(U 39-E), hereby submits the Locational Net Benefit Analysis Working Group's First Intermediate Status Report on Long-Term Refinements.

Respectfully submitted,

*/s/ Jonathan J. Newlander*

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November 10, 2016

Attachment

# Intermediate Status Report on Long-Term LNBA Refinement

## Table of Contents

### Contents

Intermediate Status Report on Long-Term LNBA Refinement .....	1
Table of Contents .....	1
Acronyms .....	1
Summary .....	2
Introduction and Background .....	3
Summary of Progress .....	6
Topics 6.2.1.(A-D).....	6
Other long-term LNBA issues:.....	8
Next Steps .....	10
APPENDIX A.....	11
6.2.1.A. Scoping Document.....	11
6.2.1.B. Scoping Document:.....	13
6.2.1.C. Scoping Document:.....	18
6.2.1.D. Scoping Document.....	22
Data access scoping document.....	25
Data access matrix .....	28
APPENDIX B: Meeting Summaries .....	37

### Acronyms

- ACR: Assigned Commissioner Ruling R-14-08-013
- CSF: Competitive Solicitation Framework
- DRP: Distribution Resources Plan proceeding
- DER: Distributed energy resource
- DERMS: Distributed energy resources management system
- DLMP: distribution locational marginal prices
- ED: Energy Division
- IDER: Integrated Distributed Energy Resources proceeding
- ICA: Integration capacity analysis
- IOU: investor owned utility
- LNBA: Locational Net Benefits Analysis
- SIWG: Smart Inverter Working Group

## Summary

This intermediate status report on Long-Term LNBA refinement summarizes the discussions of the LNBA Working Group (WG) to date on four topics related to refinement of LNBA methodology. Discussions have been facilitated by More than Smart, and the LNBA WG has met at least once per month, starting May, 2016. It is expected to maintain this meeting frequency through Q2 2017. Meetings have been in person or via webinar and conference call. The following stakeholder groups attended at least one meeting or webinar of the LNBA WG:

- ABB Group
- Advanced Microgrid Solutions
- Alcantar & Kahl
- AMS
- Artwel Electric
- Bloom Energy
- CAISO
- California Energy Storage Alliance
- California Energy Commission
- California Public Utilities Commission
- CPUC Office of Ratepayer Advocates
- California Solar Energy Industries Association
- City of Burbank
- Clean Coalition
- Community Choice Partners
- Community Renewables
- Comverge
- DNV GL
- ECCO International Inc.
- Energy and Environmental Economics
- Electric Power Research Institute
- Energy Foundation
- Environmental Defense Fund
- Gratisys Consulting
- Greenlining Institute
- Helman Analytics
- ICF International
- Independent Energy Producers Association
- Independent advocates
- Independent consultants
- Integral Analytics
- Interstate Renewable Energy Council
- Kevala Analytics
- Lawrence Berkeley National Laboratory
- Lawrence Livermore National Labs
- Natural Resources Defense Council
- Northern California Power Agency
- NextEra Energy
- New Energy Advisors
- Nexant
- Open Access Technology International
- Pacific Gas and Electric Company
- PSE Healthy Energy
- Quanta Technology
- Sacramento Municipal Utilities District
- San Diego Gas & Electric
- SEIA
- Shute, Mihaly & Weinberger LLP
- Siemens
- Smart Electric Power Alliance
- SoCal REN
- SolarCity
- Solar Retina
- Southern California Edison
- Stem Inc.
- Strategy Integration
- Sunrun
- SunPower
- The Utility Reform Network
- UC Berkeley
- Vote Solar

## Introduction and Background

In accordance with a May 2, 2016 ACR in the DRP proceeding<sup>1</sup> (R-14-08-013), the LNBA Working Group was established to monitor and provide consultation to the IOUs on the execution of Demonstration Project B and further refinements to LNBA methods. Energy Division staff has oversight responsibility of the working group, but it is currently managed by the utilities and interested stakeholders on an interim basis. The utilities have jointly engaged More Than Smart for this function. The Energy Division may at its discretion assume direct management of the Working Group or appoint a Working Group manager<sup>2</sup>.

The Working Group serves four main purposes:

1. Monitor and Support Demonstration Project B
2. Continue to improve and refine the LNBA methodology
3. Coordinate with IDER system-level valuation activities of the IDER cost effectiveness working group
4. Coordinate with the IDER CSF working group where objectives may overlap (e.g., the definition and description of grid services vs. DER performance requirements and contractual terms needed to ensure DERs meet the identified grid services).

The ACR identifies the following four long-term refinement activities (ACR 6.2 Pg. A37) on which that the Working Group shall consult to the IOUs to continue advancement and improvement of the LNBA methodology:

- (A) *Methods for evaluating location-specific benefits over a long term horizon that matches with the offer duration of the DER project. For example, there may be economic benefits in deferring network augmentations in the far future; however the benefits are likely to be discounted due to uncertainty. This work should explore whether / how probability estimates, based on the utility's past and current distribution planning experience, could be made that (1) an as-yet undetected need for upgrades will be required during the distribution planning period and (2) procurement of DERs that have a timescale greater than the distribution planning period will avoid future upgrades subsequent to the distribution planning period.*
- (B) *Methods for valuing location-specific grid services provided by advanced smart inverter capabilities. Examples include the following seven smart inverter functions identified by the Smart Inverter Working Group : (i) DER Disconnect and Reconnect Command, (ii) Limit Maximum Real Power Mode, (iii) Set Real Power Mode, (iv) Frequency-Watt Emergency Mode, (v) Volt-Watt Mode, (vi) Dynamic Reactive Current Support Mode, and (vii) Scheduling power values and modes*
- (C) *Consideration, and if feasible, development of, alternatives to the avoided cost method, such as distribution marginal cost or other methods<sup>3</sup>*

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<sup>1</sup> A modified ACR was granted on August 23 to modify specific portions of the May 2, 2016 ACR.

<http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M166/K271/166271389.PDF>

<sup>2</sup> ACR R-14-08-013 Section 6: "LNBA Working Group"

<sup>3</sup> Vote Solar supported this in post-workshop comments, referring to Dr. Eric Woychik's presentation, "LNBA to Integrate and Optimize DERs for Maximum Value," Presented at the Locational Benefits Analysis Workshop, (R.14-08-013), February 1 2016.

(D) *The IOUs shall determine a method for evaluating the effect on avoided cost of DER working “in concert” in the same electrical footprint of a substation. Such DER may complement each other operationally using a distributed energy resource management system (DERMS).*

In accordance with R-14-08-013, a first intermediate status report on long-term LNBA refinement is to be filed 180 days after the establishment of the Working Group. This document serves as the aforementioned intermediate status report.

In compliance with the ACR, the LNBA WG meets at least once a month, sometimes in conjunction with the ICA Working Group. The schedule and topics of meetings to date is shown below (topics include both short term topics related to the LNBA Demonstration Project and long term topics on refinement of LNBA which are highlighted in bold):

Meeting Date	Topic(s)
May 12 – 1:00pm-3:00pm Webinar (combined ICA/LNBA WG webinar)	Opening meeting
June 1- 9:00am-3:00pm In person (combined ICA/LNBA WG meeting)	First discussion of demonstration implementation plan before June 16 <sup>th</sup> submission
June 9 – 9:00am-3:30pm In person (combined ICA/LNBA WG meeting)	Second discussion of demonstration implementation plan before June 16 <sup>th</sup> submission
July 5 – 2:00pm-4:00pm Conference call, combined ICA/LNBA WG call)	Call to discuss submission of demonstration implementation plan
July 26 – 9:00am-4:00pm In person	Discussion of submitted stakeholder comments on demonstration implementation plans Use cases (focusing on procurement use case) Grid services (6.1.b) E3 methodology Data & maps (6.1.a)
August 31 – 9:00am – 4:15pm In person (combined ICA/LNBA WG meeting)	Clarification on use cases <b>Initial scoping discussion on long-term refinement issues (6.2.1.(A-D))</b>
September 30 – 9:00am-4:00pm In person (combined ICA/LNBA WG meeting)	Demo B status update <b>Data access discussion</b>
October 19 - 9am-12:30pm (webinar)	<b>Second scoping discussion on long-term refinement issues (6.2.1.(A-D))</b>
October 27 – 12:30pm-2:30pm (webinar)	Grid services and project deferability criteria for Demo B

Detailed agendas are available within the full meeting summary notes located in Appendix B. The short-term items discussed will be documented in the final LNBA WG report, in accordance with the August 23 ACR.

In accordance with the ACR (pg. A19), the Working Group shall be open to the public and informal in nature. To establish general consensus during the monthly meetings (both in-person and webinar), More than Smart has asked for a show of hands and/or an audible vote of consensus, with opportunity for WG members who object to the consensus point being raised to do so. WG members are also encouraged to submit comments on all prepared and shared documents, including the meeting summary, stakeholder-submitted comments, stakeholder-submitted scoping documents, IOU demo implementation plans, and other draft documentation.

The WG agreed that the intermediate status report on long-term LNBA refinement would be used to provide scope and frame the discussions on long term refinement for 2017. Thus, the bulk of discussion on long-term refinement issues to date has been dedicated to determining whether questions were within or out-of-scope of the LNBA WG.

Another key long-term refinement issue is data access, for both utilities and 3<sup>rd</sup> parties. Because this topic was agreed upon as an important long-term refinement topic for both the ICA and LNBA WGs, the full scope of data access discussions will be addressed in an ICA interim long-term refinement report (due Q4 2016) which is analogous to this report. To date, a draft scoping document has been prepared and WG members have submitted comments to the scoping document. This enables planned discussion from the upcoming November WG meetings to be incorporated. The main focus of this intermediate report on long-term LNBA refinement will be topics 6.2.1(A-D) as outlined in the ACR, as well as additional items that WG members have raised for consideration as a long-term refinement issue.

The WG process for addressing long-term LNBA refinements to-date has been as follows:

1. Assign WG members to draft initial scoping documents for each of the four identified topics (August 31 WG meeting)
2. WG members to review and comment on initial scoping documents
3. Initial scoping document authors present their documents on each of the four topics for WG discussion, and WG establishes process for developing intermediate report (October 19 WG meeting)
4. WG members to review and comment on revised initial scoping documents
5. WG authors of scoping documents to incorporate and make necessary revisions

The WG agreed at the October 19 meeting that these scoping documents, stakeholder comments and meeting discussion notes would form the basis for this report, and that the process for drafting the report would be as follows:

1. The WG is to provide comments on the draft scoping documents for topics 6.2.1.(A-D), drafted by LNBA WG members, by Wednesday, 10/26.
2. More than Smart is to circulate a first draft of the report to WG members on Monday, 10/31.
3. WG members are asked to provide comments by 11/7
4. The report is finalized and submitted by 11/10 (180 days after the establishment of the WG).

## Summary of Progress

### Topics 6.2.1.(A-D)

The following is a summary of discussion to-date on topics 6.2.1.(A-D). The WG assigned four members as initial lead authors in drafting a short scoping document that summarizes long-term refinement topics and areas for discussion, to begin in 2017. These authors were identified as:

- 6.2.1.A.: David Castle (Southern California Edison)
- 6.2.1.B: Larsen Plano (Pacific Gas and Electric Company)
- 6.2.1.C: Steve Moss (EDF), James Fine (EDF), Jim Baak (Vote Solar)
- 6.2.1.D: Sahm White (Clean Coalition)

Full scoping documents for each topic may be found in Appendix A. WG members were asked to submit comments on the scoping documents, and original authors were asked to make revisions to the scoping documents as appropriate to reflect stakeholder comment and input. The following sections summarize discussions on those scoping documents.

**6.2.1.A:** Methods for evaluating location-specific benefits over a long-term horizon that matches with the offer duration of the DER project.

The LNBA WG discussed the following questions and statements that provide a framework for further discussion in 2017.

1. The Working Group would like to better understand uncertainty in distribution planning, both within and outside of the current 10-year planning window, including key drivers of uncertainty and magnitude of uncertainty.
2. The Working Group would like to understand what is defined as “undetected needs”, potentially coming up with an agreed-upon definition. The Working Group would like to discuss possible approaches to understanding the likelihood and magnitude of future undetected needs, including analyzing data on the recent magnitude of needs that were detected between planning cycles, and whether existing approaches suffice or if new approaches would be more appropriate to determine undetected needs.
3. The Working Group would like to explore whether it is appropriate to estimate system needs/projects/costs beyond the 10-year planning window, as well as whether DER deployment can mitigate these costs.
4. The Working Group would like to better understand opportunities for short-term deferral rather than constraining consideration of DER alternatives within a typical 10-year planning window.
5. The Working Group agrees that conversations within this topic should be kept technology neutral.
6. Components of this discussion are related to procurement. There is consensus agreement that these discussions need to be addressed, but the WG is not in consensus with regards to the format and location (for example: within DRP, another ongoing CPUC proceeding such as IDER, or a separate proceeding) for how these conversations should be held.

*6.2.1.B: Methods for evaluating location-specific grid services provided by advanced smart inverter capabilities.*

The LNBA WG discussed the following questions and statements that provide a framework for further discussion in 2017.

1. There is agreement that the seven inverter functions as identified in the Smart Inverter Working Group (SIWG) are sufficient for discussion.
2. The scoping document provides a useful framing of grid services enabled by smart inverter functions by directly mapping grid services as defined in IDER Competitive Solicitation Framework (CSF) Working Group final report to the LNBA components as defined in the ACR.
3. The Working Group agrees that two smart inverter capabilities outlined in SIWG do not directly map to an LNBA component – transmission reliability (frequency response/inertia) and distribution upgrade deferral (demand reduction).
  - It is proposed that transmission reliability (frequency response/inertia) should be considered embedded in existing energy, ancillary services, and capacity components' avoided costs until a separate market for these services is established.
  - It is proposed that distribution upgrade deferral (demand reduction) might be included under a new component within the LNBA.
4. New methodologies or methodology refinement may be required to evaluate smart inverter capability or grid function in response to an identified need, but there are also practical challenges of actually deploying smart inverters to solve that need (e.g. the communications, control systems, and all associated work to enable the intelligent dispatching of smart inverters to provide a needed function). This will be undertaken after evaluation of Demo B final results.
5. The WG would like to better understand the value of smart inverter services, as defined within LNBA.
6. Given that there are instances where grid services enabled by smart inverters do not fall into the predefined LNBA categories, the WG agreed that it may be valuable to include the closest available methodology estimate and identify where estimates have been made, as well as whether it can be refined.

*6.2.1.C: Consideration, and if feasible, development of, alternatives to the avoided cost method, such as distribution marginal cost or other methods.*

The LNBA WG discussed the following questions and statements that provide a framework for further discussion in 2017.

1. The scoping document outlines the following four proposed alternative methods to the avoided cost method: 1. Deferral value based on long-run incremental costing; 2. Present value of alternative expansion plans including cost of customer interruptions; 3. Reliability differentiated rates; and 4. Annual deferral value. The WG would like to define the alternative methods and assess the benefits and drawbacks of alternative methods when compared to the avoided cost methodology. It will be important to begin long-term refinement discussions of this topic with a discussion of the definition of feasibility within this context.

2. WG members have discussed that using the present value of alternative expansion plans with the inclusion of customer interruption costs might seem the most appropriate alternative methodology, though the WG is open to continuing discussions on other alternatives.
3. The WG would like to further explore whether distribution locational marginal prices (DLMPs) can be considered as another alternative to the avoided cost method.
4. WG members would like to gain further understanding of the current calculation method used by E3 and continue discussions on whether or not discussion of 6.2.1.C should include changes to the current LNBA methodology, after reviewing Demo B final results. This topic is also discussed further in this report under **“Other long-term LNBA issues.”**

*6.2.1.D: Determine a method for evaluating the effect on avoided cost of DER working “in concert” in the same electrical footprint of a substation.*

The LNBA WG discussed the following questions and statements that provide a framework for further discussion in 2017.

1. It is proposed that this WG should review the assumptions in LNBA regarding how DER will interact on the grid, including the degree or circumstances under which they would be expected to act in concert or other coordinated fashion, and review the modeling of the impact this will have on benefits and costs realized by the utility and their customers.
2. This would require assumptions to be developed for review, and illustrated in at least one modeled example demonstrating the various impacts of coordinating distributed resources, and should reflect at a minimum the role of utility DERMS on both generation and load and of autonomous advanced inverter functionality (outside of DERMS) in coordinating DER for maximum value. These assumptions should be tested and updated through Demo C.
3. It is proposed that there is no need to change the avoided cost valuation methodology to assess the value of DER working in concert. However, DERs working “in concert” do have an impact in the context of sourcing and portfolio evaluation.

*Other long-term LNBA issues:*

Outside of the four distinct topics (6.2.1.(A-D)) outlined in the ACR, the WG also raised the following four topics as potential long-term LNBA issues for discussion, clarification, and added coordination.

1. Increasing location-specific values and overall improving granularity into the LNBA methodology, including potential methodology modifications to the E3 DERAC methodology. The WG has identified, through multiple meetings (which included the review of scoping document 6.2.1.C), the following topics for potential continued discussion after the conclusion and evaluation of the Demo B project:
  - Incorporation of DER costs generally, including grid modernization costs, including but not limited to costs for distribution reliability and automation, as a component of LNBA methodology.
  - Modification of current calculation for locational deferral value used in the E3 avoided cost calculation within the LNBA tool.
  - Inclusion of local weather conditions as a variable into the LNBA methodology.
  - Addition of location-specific values to some components of the generic system-level values in the Demo B LNBA methodology within the DERAC tool (e.g. LMP-based energy)

- Inclusion of multiple DER adoption scenarios and understanding the value of deferral over these multiple scenarios.
  - Inclusion of air quality standards and pollution as avoided cost values, in coordination with other efforts such as the Societal Cost Test efforts in the IRP and IDER proceedings
  - Understand and determine a DER's propensity to deliver energy /reduce energy needs coincident to peak loads in order to accurately predict how a particular DER will meet both capacity and duration needs.
  - Improved understanding of whether LNBA is based on cost-causation.
  - Increased use of dynamic integrated modeling when available.
  - All variable costs should be identified and then captured to the extent practical.
  - Conduct optimization modeling subject to greenhouse gas emissions constraints (an example being minimizing costs for ratepayers).
  - Methodology and sources for continually updating and revising the DERAC values included in the system level avoided costs to insure on going LNBA accuracy.
  - Analysis of how LNBA may reflected the aggregated capabilities of DER portfolios.
  - Consideration of how DER may enhance integration capacities.
2. Understanding LNBA in reference to and in coordination with other proceedings, planning processes, and WGs, including IDER, linkages to ICA Working Group, and DER procurement and load forecasting efforts.
3. Improving LNBA mapping tools after evaluating results from the Demo B project. This could include:
- Representation of multiple DER growth scenarios in heat maps.
  - Potential inclusion of projects deferring a future identified need.
4. Evaluating data access within the context of both ICA and LNBA WGs.
- Data access was identified as a key long-term discussion item for both the ICA and LNBA WGs. WG members agreed to begin a scoping process using the developed data access matrix (see Appendix A). The matrix asks the following questions:
    - i. Who wants the data? What are they trying to accomplish with this data? What is the rationale for performing this function? What data types are necessary to perform this function? Is the data available? Are there confidentiality concerns? Are there alternative data source available?
  - WG members were asked to submit inputs to the matrix on a rolling basis in advance of the November WG meeting.
  - WG members representing Vote Solar and Strategy Integration developed a draft document on the existing and new data needs of stakeholders per the WG agenda. The draft document summarizes data needs for planning purposes and outlines data gaps, including data for operational purposes (see Appendix A). Stakeholders were asked to provide comments to modify and enhance the draft (see Appendix B), which will continue to be referenced and refined in WG long-term data discussions.

5. Methodology for identifying a comprehensive list of potentially deferrable projects. While further discussion on a deferral framework will be addressed in Track 3 of the DRP proceeding, and while Demo B is demonstrating that some projects are indeed deferrable, demo projects do not include a methodology for ensuring that all potentially deferrable projects are identified. This should include a process for review by non-utility validators.

#### Next Steps

In accordance with the ACR, the WG will continue work on the long-term refinement topics and publish its final report on long-term LNBA refinements in Q2 2017. A schedule for work has to-date not yet been decided. The WG will define a process for answering the identified discussion items above within the scope of this proceeding and include recommendations and next-steps for these identified long-term refinement topics within the final report.

## APPENDIX A

### 6.2.1.A. Scoping Document

Author: Dave Castle, Southern California Edison

#### Proposed Scope Questions:

- Understanding the uncertainty in distribution planning
  - Topic (1): Within the current planning window
    - How much uncertainty is there within the latter half of the current 10 year planning window?
    - What are the drivers of this uncertainty?
      - Uncertainty of load growth (economic factors, geospatial factors, etc.)
      - Uncertainty of DER growth (resource prices, business models, NEM tariffs, rate structures, demand response participation rates, energy efficiency program participation, etc.)
      - Uncertainty of grid needs
      - Uncertainty of type of projects that would be built to meet those needs
      - Uncertainty of the cost of the project(s) ultimately designed to meet the needs
      - Uncertainty in passive generators (i.e. PV, wind) generating as predicted for time of year on peak days.
      - Uncertainty in DER failure rates and degradation (batteries in particular, we do not have long term hard data on larger scale battery banks in various operational and environmental conditions)
      - More?
    - What are “Undetected needs”?
      - To what extent do “As yet undetected” needs typically show up?
      - Is there any means available to predict these needs?
      - Is it possible to predict the projects that will be constructed to meet these needs?
      - Is there any means available to predict the cost of meeting these needs?
      - Can DER deployment mitigate these undetected needs/costs?
      - Is it appropriate to value/compensate DERs for meeting hypothetical future needs given this uncertainty?
      - **What the appropriate action in terms of refining LNBA?**
  - Topic (2): Beyond the current planning window
    - Given the uncertainty described above for the existing planning window, is it appropriate to estimate system needs beyond the 10 year window?
    - Given the above, is it appropriate to estimate what hypothetical projects would solve these hypothetical needs?
    - Given the above, is it appropriate to estimate the costs of those projects?
    - Can DER deployment mitigate these costs?
    - **What the appropriate action in terms of refining LNBA?**
- Understanding the magnitude of the issue
  - How much value are we really talking about, given that distribution value is only one of multiple value streams?
  - How much value are we really talking about, given the effect of discounting?

- If these additional avoided costs can be forecast, would additional tools / software / resources be required?
- What are some possible approaches to answering the above questions?
  - Is it worthwhile to build upon how this issue is addressed implicitly or explicitly in other CA proceedings or other states, or does LNBA require a totally different approach?
    - Typical approach to DER cost effectiveness (e.g. for DR/DG/EE) is to take current load-growth driven investment plans and normalize per MW of load growth and consider this the long-term avoided cost of local peak mitigation. Sometimes this is geospatial (e.g. using distribution marginal costs for each DPA and using DPA peaks)
    - Is this approach appropriate for the LNBA?
- Additional questions uncertainty
  - It has been suggested that DER sourcing be treated similarly to conventional wires spend.
    - Is it appropriate to “oversize” DER investments, given that traditional wires solutions may be oversized?
    - Conventional solutions (wires, transformers) are lumpy whereas DERs are less so. Additionally, it is possible to solicit additional DERs later on. Does this mean less DER should be procured?
    - **How does this discussion impact LNBA?** Does this impact LNBA at all, or is this a *sourcing* question?

Do DERs provide greater/less optionality than conventional solutions? If so, **how should this be reflected in the LNBA?** (Or is this really a *sourcing* question?)

6.2.1.B. Scoping Document:

Author: Larsen Plano, PG&E

**Background:**

The May 2, 2016 Assigned Commissioner Ruling (ACR) on Integration Capacity Analysis (ICA) and Locational Net Benefit Analysis (LNBA) created the LNBA Working Group for four purposes:

1. Monitor and support the LNBA Demonstration Project (Demo B)
2. Improve and refine the LNBA methodology
3. Coordinate with IDER Cost Effectiveness Working Group
4. Coordinate with IDER Competitive Solicitation Framework Working Group

Specific activities for the working group include two short-term activities related to Demo B and four long-term activities related to LNBA refinements. One of the four long-term activities is methods for valuing location-specific grid services provided by advanced smart inverter capabilities:<sup>4</sup>

*Methods for valuing location-specific grid services provided by advanced smart inverter capabilities. Examples include the following seven smart inverter functions identified by the Smart Inverter Working Group<sup>5</sup>: (i) DER Disconnect and Reconnect Command, (ii) Limit Maximum Real Power Mode, (iii) Set Real Power Mode, (iv) Frequency-Watt Emergency Mode, (v) Volt-Watt Mode, (vi) Dynamic Reactive Current Support Mode, and (vi) Scheduling power values and modes*

The Smart Inverter Working Group is a technical working group created to help guide the implementation of smart inverters in California, including recommended changes to DER-related standards and tariffs.

**Proposed Framework:**

The following steps compose a proposed framework for addressing this long-term refinement:

1. Determine what, if any, additions or subtractions to the seven capabilities are needed
2. For each smart inverter capability, assign specific grid services enabled by the capability
3. For each capability/grid service pair, determine which LNBA component, if any, includes that service:
  - a. If already included in an LNBA component, determine what, if any, LNBA methodology refinement is required to evaluate that capability.
  - b. If not already included in an LNBA component, determine whether an additional LNBA component and associated methodology is needed.

**Preliminary Results:**

Step 1: Additions/Subtractions

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<sup>4</sup> See section 6.2(1)(B) of the ACR on page 36

<sup>5</sup> Original reference in ACR to a 2/1/2016 CPUC presentation, "Categorizing Distribution-Level Avoided Costs Due to Utilization of Smart Inverter Phase 3 Functions."

Preliminary Proposal: No additions/subtractions to the seven listed smart inverter capabilities are recommended. One simplification could be to group all real power control functions and reactive power control functions.

Step 2: Match capabilities and grid services

Preliminary Proposal: The following table is adapted from the 2/1/2016 CPUC presentation referenced in the ACR and includes the specific distribution services defined from the IDER Competitive Solicitation Framework Working Group Final Report:

1. Distribution Upgrade Deferral (Distribution Capacity),
2. Distribution Upgrade Deferral (Voltage Support),
3. Distribution Upgrade Deferral (Reliability-Back Tie),
4. Distribution Upgrade Deferral (Resiliency-Microgrid)

**Table 1**

Smart Inverter Capability	Grid Services													
	Tx Upgrade Deferral (Transmission Capacity)	Tx Congestion Mitigation	Tx Losses Mitigation	Tx Reliability (Spinning Reserve)	Tx Reliability (Frequency Reserve)	Dist. Upgrade Deferral (Frequency Regulation)	Dist. Upgrade Deferral (Response/Inertia)	Dist. Upgrade Deferral (Distribution Capacity)	Dist. Upgrade Deferral (Voltage Support)	Dist. Upgrade Deferral (Reliability-Back Tie)	Dist. Upgrade Deferral (Reliability-Microgrid)	Support Efficiency/Loss Reduction (e.g. CVR)	Support Safety	
1 DER Dis/Reconnect Command		X	X							X			X	
2 Limit Max. Real Power Mode	X			X			X	X	X	X	X	X	X	
3 Set Real Power Mode	X	X	X	X	X		X		X	X	X			
4 Frequency-Watt Emergency Mode						X			X					
5 Volt-Watt Mode							X		X	X	X			
6 Dynamic Reactive Current Support Mode								X		X	X	X		
7 Schedule Power Values and Modes	X	X	X	X	X		X	X	X	X	X	X		

It should be noted that these capabilities and services are largely untested at scale, and for smart inverters to provide some of these services (e.g. frequency regulation), perhaps most, enabling communication and control infrastructure will also be required.

**Step 3: Map services to LNBA Components**

Preliminary Proposal: For reference, the table below from the ACR provides the LNBA components as currently defined for Demo B. In addition, the IOUs are also asked to include opportunities for Conservation Voltage Reduction (CVR) and volt/VAR optimization (VVO) in Demo B. In the IOUs’ implementation plans, it was determined that these would be Included under avoided energy and distribution voltage support respectively.

**Table 2**

Table 2 Approved LNBA Methodology Requirements Matrix for Demonstration Project B.

Components of avoided costs from DERAC	Proposed LNBA in IOU Filings from IOU applications	Primary Analysis Required	Secondary Analysis Optional additional
Avoided T&D	Sub-Transmission / Substation / Feeder	As proposed but with modifications (1)	As proposed but with modifications (1)
	Distribution Voltage / Power Quality	As proposed but with modifications (1)	As proposed but with modifications (1)
	Distribution Reliability / Resiliency	As proposed but with modifications (1)	As proposed but with modifications (1)
	Transmission	As specified herein (2)	As specified herein (2)
Avoided Generation Capacity	System and Local RA	Use DERAC values	Use DERAC values with location-specific line losses (3)
	Flexible RA	Use DERAC values with flexibility factor (4)	Use DERAC values with flexibility factor (4)
Avoided Energy	Use LMP prices to determine	Use DERAC values	As proposed but with modifications regarding use of LMP prices (5) and location-specific losses (3)
Avoided GHG	incorporated into avoided energy	Use DERAC values	As proposed
Avoided RPS	similar to DERAC	Use DERAC values	As proposed
Avoided Ancillary Services	similar to DERAC	Use DERAC values	As proposed
additional to the DERAC	Renewable Integration Costs	values or descriptions of these benefits (6)	values or descriptions of these benefits (6)
	Societal avoided costs	values or descriptions of these benefits (6)	values or descriptions of these benefits (6)
	Public safety costs	values or descriptions of these benefits (6)	values or descriptions of these benefits (6)

The following table maps the smart grid services identified in Step 2 to LNBA components. At present two services identified don’t clearly map to an LNBA component as those components are currently defined, Tx Reliability (Frequency Response/Inertia) and Dist. Upgrade Deferral (Hosting Capacity).

**Table 3**

LNBA Component	Grid Services													
	Tx Upgrade Deferral (Transmission Capacity)	Tx Congestion Mitigation	Tx Losses Mitigation	Tx Reliability (Spinning Reserve)	Tx Reliability (Frequency Reserve)	Tx Reliability (Frequency Regulation)	Dist. Upgrade Deferral (Response/Inertia)	Dist. Upgrade Deferral (Distribution Capacity)	Dist. Upgrade Deferral (Voltage Support)	Dist. Upgrade Deferral (Reliability Back Tie)	Dist. Upgrade Deferral (Reliability Microgrid)	Efficiency/Loss Reduction (e.g. CVR)	Support Safety	
1 Sub-tx/Substation/Feeder (Distr. Project Deferral)										X				
2 Distr. Voltage/Power Qual. (Distr. Project Deferral)										X				
3 Distribution Reliability/Resiliency										X	X			
4 Transmission (Trans Project Deferral)	X	X	X											
5 System and Local RA														
6 Flexible RA														
7 Avoided Energy			X	X										X
8 Avoided GHG			X	X										X
9 Avoided RPS														
10 Avoided Ancillary Services				X	X	X								
11 Renewable Integration Costs				X										
12 Societal Avoided Costs														
13 Public Safety Costs														X

Step 3a: For services which are included in LNBA components, consider methodology enhancements

Preliminary Proposal: The intent is to define technology agnostic requirements for DERs to capture the benefits (i.e. avoided cost) associated with each LNBA component – for example provide a given amount of load reduction at a given time and/or with a given amount of advance notice. If Demo B results indicate that this approach is successful, it is unlikely that additional methodology enhancements are needed to capture smart inverter capabilities.

Step 3b: for services not included in LNBA components, consider an additional component

Preliminary Proposal: The two smart inverter capabilities that do not map to an LNBA component are Tx Reliability (Frequency response/Inertia) and Dist. Upgrade Deferral (Hosting Capacity). The light-gray X's in Table 3 indicate that these could be included, respectively, under LNBA components 10 (Avoided Ancillary Services) and component 1 (Sub-Tx/Substation/Feeder Distribution Project Deferral)

For frequency response/inertia, there is not currently a market or price associated with these services, as they are simply required under the CAISO generator interconnection agreement, and any associated costs would be recouped through revenue from the sale of energy, ancillary services and capacity. Until a separate market for these services is established, they should be considered embedded in the existing energy, ancillary services and capacity components' avoided costs.

For hosting capacity, it is expected that this will eventually be considered a distribution deferral opportunity as with opportunities to defer other distribution upgrades; however, there is not yet an established process for explicitly determining distribution hosting capacity needs and associated projects. Once such a process exists, it may make sense to include this service under a new Distribution Upgrade Deferral (Hosting Capacity) component in LNBA.

The methodology for this deferral would likely follow the same framework as other distribution deferral benefit calculations. In addition, on principle, a DER should not receive additional compensation for correcting a hosting capacity issue that is caused by that DER, which should be quantified in future iterations of the LNBA.

6.2.1.C. Scoping Document:

More Than Smart, Working Group (WG)

**Objectives and Scope for Long-Term Refinements Related to Items Outlined in 6.2.1**

*Discussion Draft*

Authors: James Fine and Steven Moss, EDF; Jim Baak, VoteSolar

**Document Purpose:** Identify the scope of issues, or questions to develop a scope of issues, associated with “Activity Related to Continuing Refinements to LNBA...(C) Consideration, and if feasible, development of alternatives to the avoided cost method, such as distribution marginal cost or other methods.”

**Process and Timeline:** These draft documents will be made available via the <http://www.drpgw.org> website within 14 days (i.e., September 15); WG members will have seven days (i.e., until September 22) to provide comments; and the September WG meeting agenda will include discussion and pursuit of a consensus on a scope of issues to be addressed related to (C) above, under what schedule, the results of which will be reflected, as applicable, in the status and final (second quarter, 2017) reports on long-term LNBA refinements.

***Proposed Scope of Issues for Long-term Refinements to LNBA Methods:***

*[Add discussion of where avoided and alternative cost analyses fit into LNBA process, and how used in other settings, such as GRC. Include in this discussion how current regulation expresses costs through tariffs/prices.]*

***LNBA.6.1.2.C: Marginal distribution cost analysis methods***

***Evaluate Marginal Cost (MC) Methodologies:*** Identify potential analytical methods, and associated data requirements, available to calculate distribution marginal costs. Concepts to consider include:

- “Deferral value” of Distributed Energy Resources (DERs) at the distribution system level based on long-run incremental costing (LRIC). In the T&D context, LRIC is the change in costs usually associated with a change in utility circumstances.<sup>6</sup> This approach may seek to capture a needed utility response, such as to further integrate DERs. Simple valuation compares the prior construction and operational costs without the change (load/resource) to the new construction and operational costs with the change. This is then consistent with direct comparison of distribution projects versus DERs.
- “Present Value” comparison of the two alternative expansion plans (DER centric or traditional) in kW, kWh, and kVAR terms.<sup>7</sup> Add in reliability measures to avoid systematically understating the value of incremental grid modifications, where customer reliability is captured as “interruption costs.”<sup>8</sup>

<sup>6</sup> S. Oren, [Area-Specific Marginal Costing for Electric Utilities: A Case Study of Transmission and Distribution Costs](#), Doctoral Thesis, Stanford University, September 1989, pg. 30.

<sup>7</sup> See, M. Munasinghi, [Electric Power Economics](#), Butterworths, 1990, at pp. 136-137 NS pp. 23-243.

<sup>8</sup> See, Updated Value of Service; <https://emp.lbl.gov/sites/all/files/value-of-service-reliability-final.pdf.pdf>.

- “Reliability Differentiated Rates” methods: Similar to Oren’s 1989 thesis, which contributed to PG&E filing area-specific marginal cost data as part of its General Rate Case revenue allocation proposals starting in the early-1990s, PG&E and others have advanced innovative techniques to value reliability, some of which could ultimately be translated into tariffs/prices. Agricultural advocates, among others, have recommended adoption of reliability-differentiated rates.<sup>9</sup>
- “Annual Deferral Value” of planned investments that are potentially deferrable. See demonstration interactive map at <http://nationalmap.gov.au/renewables/> and methods developed at the Institute of Sustainable Futures at the University of Technology Sydney.<sup>10</sup>
- *Evaluate Non-MC Methods*: These could include embedded costs and Ramsey pricing.

This task is to describe the strengths and weaknesses, and typical applications, of these approaches, and contrast and compare them with one another, including:

1. Marginal cost calculation methods submitted as part of General Rate Case proceedings, including discussion of the strengths and weakness of key underlying elements;
2. Use of time series (aka, panel) data to establish long-term marginal costs;
3. Use of emerging market referents, including comparing distributed energy resources on an equivalent basis.
4. Use of project-specific RFO data to create marginal distribution system cost data

*Needs Assessment: Compare Investor-Owned Utilities (IOU) LNBA incremental cost methods in use in 2016 against long-term needs for more precise costing methods:*

1. Identify need(s) and timeline for increasing the precision of distribution marginal costs
2. Identify improvements needed to enable marginal cost estimation at increasing precision in time and place.

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<sup>9</sup> See for example, [http://www.caiso.com/Documents/AttachmentB\\_ISOResponsesCommentsDraft2012-2013TransmissionPlan.pdf](http://www.caiso.com/Documents/AttachmentB_ISOResponsesCommentsDraft2012-2013TransmissionPlan.pdf)

<sup>10</sup> See Research Principal is Edward Langham, Institute for Sustainable Futures | University of Technology Sydney Level 11, Building 10, 235 Jones Street Ultimo NSW 2007 (PO Box 123), T +61 2 9514 4971 M +61 403 820 913 E [edward.langham@uts.edu.au](mailto:edward.langham@uts.edu.au) web: [isf.uts.edu.au](http://isf.uts.edu.au).

“Annual Deferral Value (expressed in \$/kVA/year) is the planned investments that are potentially deferrable, noting that many replacement investments are not nominated as deferrable. In addition, the amount of network support (in MVA) from demand management or renewable energy required in a given year to achieve a successful deferral is calculated. Annual Deferral Value shows the effective cost of addressing upcoming network constraints through the preferred network solution. This annual value can be thought of as an upper bound to the amount that the network could invest in equivalent non-network options (such as demand management or distributed generation) to alleviate a constraint for that year. If less than this upper bound is spent addressing the constraint using non-network options, then overall the cost to network service providers and consumers is lower. ...calculated by determining the annualised value of deferring the network solution (avoided depreciation and interest paid on capital), and dividing this by the amount of network support (in kVA) that would be required in that year to achieve the deferral. Note that while the \$/kVA/yr figure shown is a marginal value (i.e. for each kVA of capacity supplied), a whole year’s the demand growth is generally required in network support to enable a successful deferral to be achieved. That is, a sufficiently large quantum of network support is required.”

3. Establish a plan to incorporate LNBA improvements, such as increased costing precision and, as needed to inform costing precision, more comprehensive accounting of all costs and benefits from all stakeholders' perspectives, including future ratepayers and utility shareholders.

*Assess Data Availability:* Further hone data needs to support preferred methods to calculate distribution marginal costs.

1. Assess current and reasonably anticipated data sources
2. Identify outstanding data needs associated with each incremental cost analysis method.
3. Identify data needed by DER providers and rate payers potentially investing in DERs

*Regulatory assessment:* Determine what regulatory actions are necessary to enable, and/or compel the use of improved costing methods, in what applications.

*Regulatory coordination:* Determine what other proceedings, pilots and demonstrations should be updated to reflect ambition for improved costing approaches as part of LNBA.

*Additional Long Term Improvements for LNBA Modeling.* Consideration should be given to the following modeling improvements:

1. Inclusion of a full set of costs and benefits;
2. Conduct dynamic integrated modeling<sup>11</sup>;
3. Use of marginal distribution costs as LNBA inputs;
4. Link modules for ICA, LNBA and procurement/DER and load forecasts
5. Conduct optimization modeling subject to greenhouse gas emissions (GHG) constraints, such as minimizing for ratepayer costs (using total resource cost LNBA tests), maximizing DER benefits for DER investor
6. Test hypothesis: if based on cost causation with sufficient precision to reflect DER capabilities, then grid costs are minimized too.

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<sup>11</sup> EDF described the interactions of these modules in Comments filed Comments Of EDF On Assigned Commissioner's Ruling On Track 3 Issues for the DRP proceeding, R14-08-013, filed Aug. 22, 2016, pgs 7-8:

"Given the important and influential interactions between market forces and DER penetration, as well as the need to encourage market participation, forecasts used for integrated capacity analysis (ICA) and LNBA, as well as for sourcing cycles, need to be more dynamic. Ultimately, utilities need to evolve towards the kind of iterative, faster-paced forecasting done by private sector companies, like banks and technology firms.

EDF believes that the DER penetration forecast should be updated regularly in order to accurately consider benefits and value of DERs to customers (topics 10 and 11), and should be functionally and dynamically tied to procurement outcomes and inputs into the LNBA and ICA modules. Doing so will allow for iterative solving of a DER optimization function that includes both minimizing grid-costs for all ratepayers and minimizing the energy bills (and providing other benefits, such as carbon footprint reduction) of customers who invest in DERs.

Therefore, EDF recommends this subtrack consider how best to iteratively update forecast inputs. Similar to updating LNBA studies, to the extent that customer DER investments can be responsive to ICA constraints (as identified by the utility in ICA studies and reflected in pricing and marketing), then the ICA inputs should be updated to reveal these customer responses. For example, an ICA study could reveal that rooftop PV systems on a given distribution feeder will be limited unless they are installed with smart inverters capable of avoiding frequency spikes. Subsequently, as DER investors respond with only smart inverter-enabled installations, then the DER forecasts and ICA study for that area should reflect this type of DER penetration and the associated capabilities."

*Uncertainty and Scenario Analysis*

1. List risks, including loss of load probability, grid reliability and GHG constraint violation; evaluate risks probabilistically using dynamic modeling platform;
2. Categorize uncertainties as analytically tractable or exogenous to the LNBA-ICA-procurement modeling platform;
3. Conduct scenario analyses.

6.2.1.D. Scoping Document

Author: Sahm White, Clean Coalition

*Proposal: This working group should review the assumptions regarding how DER will interact on the grid, including the degree or circumstances under which they would be expected to act in concert or other coordinated fashion, and review the modeling of the impact this will have on benefits and costs realized by the utility and their customers. This will require assumptions to be developed for review, and illustrated in at least one modeled example demonstrating the various impacts of coordinating distributed resources, and should reflect at a minimum the role of utility DERMS on both generation and load and of autonomous advanced inverter functionality (outside of DERMS) in coordinating DER for maximum value. These assumptions should be tested and updated through Demo C.<sup>12</sup>*

*This focus on coordination of DER is in addition to any refinement of portfolio composition, location, or granularity of analysis.*

6.2.1(D) requirement has two separate components –

- a) A method for establishing costs that may be avoided, and
- b) A method for determining whether DER working “in concert” influences the ability of DER to avoid those costs.

a). For the first of these, the initial basis for evaluating avoided cost is proposed as identifying physical upgrades that can be avoided or deferred through DER alternatives, and comparing the cost of the traditional upgrade against the cost of the DER alternative as established through competitive solicitation. There are outstanding issues regarding the use of alternative solicitation and incentive measures to acquire DER services at lower cost, the application of return-on-equity earnings and discount rates in determining ratepayer costs, and identification of additional benefits and costs that would be realized beyond the capital investment, if any.<sup>13</sup> These issues are being addressed elsewhere in this working group and are beyond the scope of 6.2.1(D). Additionally, the use of alternative sourcing mechanisms, such as tariffs and incentive programs, to acquire DER services will be addressed in the IDER proceeding.

The valuation of avoided costs is determined by what cost are avoided (and the method of valuation), not by how the replacement services are best obtained – that is to say, regardless of whether they are achieved by the operation of a single DER or multiple DER working in concert. Once the operational

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<sup>12</sup> See Assigned Commissioner’s Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resource Planning, dated February 6, 2015 (“DRP Ruling”), Attachment, Guidance for Section 769 – Distribution Resource Planning, (“Final Guidance”) at p. 6 (providing that Demo C should demonstrate both how DERs operate in concert with existing infrastructure and “explicitly seek to demonstrate the operations of multiple DER types in concert”).

<sup>13</sup> Note that if the methodological approach is limited to a pre-defined avoidable upgrade, then avoided cost value is fixed, and the only variable to consider is whether fewer DER resources are required if they are an appropriate portfolio working in concert.

characteristics are established, the value of that operation is divorced from the source and the avoided cost basis is technology neutral. In this sense, whether or not DER are working in concert will not require any modification of the avoided cost methodology in and of itself. Thus, this issue does not need to be addressed within the context of Topic D.

b). However, while the avoided cost methodology itself does not change, the determination of the operational characteristics is very much dependent upon understanding and appropriately modeling the combined effects of multiple DER and the degree to which they are acting together as a coordinated system. A portfolio of DER working “in concert” will perform differently and have greater capacity and functionality than the same DER operating in an uncoordinated manner. Because the avoided cost basis does not change, there is not an impact to the locational benefits assessment potential that will be reflected on the LNBA maps<sup>14</sup>. However, these are important questions that need to be addressed in the context of sourcing and valuation of DER portfolios and the type and level of services they provide.

Where portfolios of DER are defined by bidders in response to a request for offers (RFO), each bidder may be responsible for defining the operational capabilities of their portfolio and assuring performance to the parameters. These values may be used directly in the DER valuation and selection process through which the net benefit to cost of each alternative is evaluated – for example, the bidder’s portfolio could be treated as a facility with the characteristics defined by the bidder.<sup>15</sup>

However, these DER portfolios will not exist in isolation, but will be operating along side other individual and aggregated DER located on the same area of the electric distribution system. *This working group should ensure that the assumptions regarding how DER will interact on the grid, including the degree or circumstances under which they would be expected to act in concert or other coordinated fashion, and the impact this will have on benefits and costs realized by the utility and their customers, will be reviewed in an appropriate forum such as IDER proceeding or during the stakeholder review of Demo C results. This may require assumptions to be developed for review, and should reflect at a minimum the role of utility DERMS and advanced inverter functionality in coordinating DER for maximum value. These assumptions should be tested and updated through Demo C.*<sup>16</sup>

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<sup>14</sup> In this context the LNBA maps reflect the location specific net present value of the costs that are potentially avoided through the use of DER.

<sup>15</sup> If the method of establishing the value is to establish the market price of a DER portfolio, then this method need not be changed based on whether the DER are working in concert – however the ability of the combined DER portfolio to meet the operational requirements resulting in the avoided upgrade must be affirmed through an appropriate methodology capable of modeling that coordinated functionality.

<sup>16</sup> See Assigned Commissioner’s Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resource Planning, dated February 6, 2015 (“DRP Ruling”), Attachment, Guidance for Section 769 – Distribution Resource Planning, (“Final Guidance”) at p. 6 (providing that Demo C should demonstrate both how DERs operate in concert with existing infrastructure and “explicitly seek to demonstrate the operations of multiple DER types in concert”).

For example, there are clearly very significant differences in the avoided cost value of 5 MW of PV within the electrical footprint of a substation depending on how those 5 MWs are distributed within and across the circuits, including the generation to load profile in each line section, and the difference in aggregate generation profile associated simply with geographic diversity within the circuits. Multiple PV systems distributed on the same circuit will have greater total reliability and less aggregate variability than the same capacity from a single system, and the response to voltage fluctuations will be more nuanced and efficient under the coordination of a DERMS or even under individual autonomous operation programmed to monitor and respond to local grid conditions in manner similar to coordinated DERMS signals.

Combining DER with complimentary attributes will further enhance their capability to achieve the performance required to avoid the defined costs beyond that realized by simply adding the value of each DER operating individually or independently. For example, PV and electric vehicles can complement each other to provide more reliable availability of power within a circuit or substation. The value of an avoided cost (such as an upgrade) remains technology agnostic to its alternative, even though the quantity or quality of services provided by the DER is not agnostic to coordination – as such it may require fewer DER, or less DER capacity to achieve the performance required to avoid the fixed defined costs.

As such, the methodological enhancement required is not in calculating the value of any costs which are avoided, but in determining how the aggregation and coordination of individual resources will change the value proposition of the DERs.

Note that if the methodological approach is to define an avoidable upgrade, that avoided cost value is fixed, and the only variable to consider is whether fewer DER resources are required if they are an appropriate portfolio working in concert.

Data access scoping document

9 September 2016

To: ICA/LNBA More-Than-Smart Working Groups

From: Eric Woychik and Jim Baak

RE: Existing and New Data Needs of Stakeholders Per Working Group(s) Agenda

This is to ask for review, feedback and suggestions on this initial effort to assess and define ICA/LNBA data needs and current data availability, by 20 September. As discussed in the ICA/LNBA MTS meeting last week, this task is to define the scope in a summary way.

First data for planning purposes is summarized. Second, data gaps are outlined including data needs for operational purposes. As a backdrop, LBNL's public demand response data base, which looks to be very useful, is outlined. LBNL has successfully clustered new data to anonymize, making it publically available. Information on this LBNL effort including detailed data/results can be found at <http://www.cpuc.ca.gov/General.aspx?id=10622>.

#### Data for Planning Purposes

Some of the expected planning data needs, which may also include analytic results, are summarized as follows:

- End use DER penetrations in fractional load terms (by cluster).
- Building type and weather station data, in 8760 profiles (by cluster).
- Load shapes for specific end uses (by cluster).
- Load reductions (Additional Achievable Energy Savings or AAEE).
- Fraction of load in forecast areas.
- End-use penetrations, including electric vehicles (EVs).
- Proportions of EVs in each SLAP (Sub LAP).
- Load profiles for EVs and charging areas.

#### Data Gaps Including Data for Operational Purposes

Data limits and possibly gaps are suggested in each of the following questions:

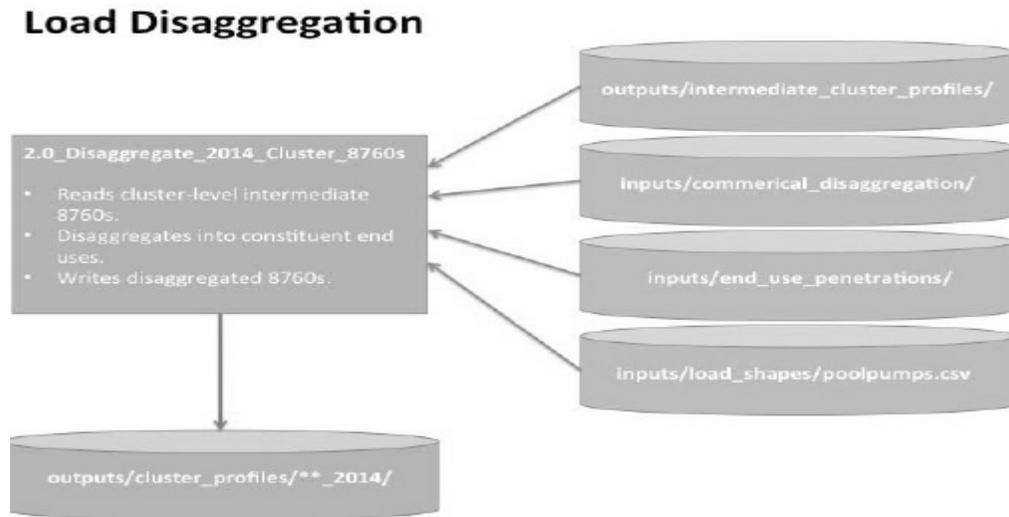
- What DERMS data use/needs will be handled by distribution wires company (so need not be provided)?
- Aggregate customer load data at distribution transformer and circuit levels upon which to base DER use.
- Data to monitor the status of end-uses to know load-shift/management potential.
- Results from grid analysis to schedule/use DERs for reliability, power quality, and to ensure asset deferral.
- Appropriate interval and alert level communications to schedule use of DERs, specifically DR, Storage, and smart inverters, including system (CAISO) data.
- Smart inverter data, including inverter settings, for volt/VAR and supply management.
- Specification of data attributes, refresh intervals, and data transfer needs to provide secure, synchronous access to accurate and clear energy usage and billing data.

Data from LBNL DR Potential Study – Which Exemplifies Current Data Availability

LBNL provided a webinar on modeling for its latest demand response (DR) potential study, supported by CPUC and the IOUs, which Dr. Woychik participated in. From this and the study a number of new useful data elements were unpacked and anonymized with clustering techniques (and CPUC oversight). The study places previously available and newly available data in the public domain. A summary of some of the end-use files used in the study follows:

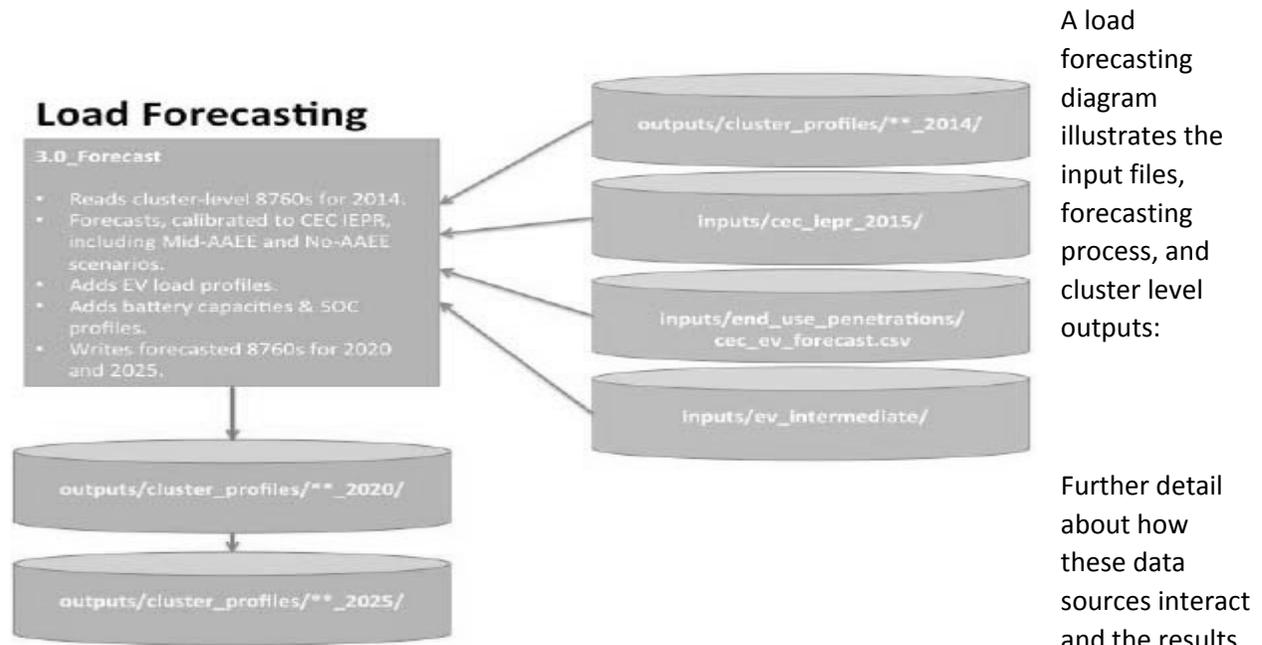
File/Directory Name	Description
end_use_penetrations/ ind_disaggregation_inputs.csv	Defines the fractions of annual load attributable to process and non-process loads for different industrial subsectors. Includes data from MECS 2010.
commercial_disaggregation/ ...	This directory includes one CSV file per weather station and CEUS building type combination. Each CSV includes an 8760 profile with hourly end use fractions of the applicable end uses (e.g. ventilation, lighting, refrigeration).
end_use_penetrations/ poolpumps.csv	Defines the penetration of pool pumps in residential clusters, as a decimal. Based on RASS surveys.
load_shapes/ poolpumps.csv	Defines the load shape of residential pool pump loads, generated based on the SCE pool pump study.

A load disaggregation diagram illustrates the input files, disaggregation, and inputs:



CEC IEPR 2015 forecasts and AAEE impacts are separately set forth in detail as shown in the following table of forecasting and load calibration input/directory files:

File Name	Description
cec_iepr_2015/ midAAEE_mwh_impacts.csv	This file contains the annual MWh load reductions attributable to AAEE for the Mid AAEE scenario as defined by the CEC. Columns are end uses, rows are pairings of utility and forecast year.
cec_iepr_2015/ **_area_adj.csv	For each IOU, one of these files exists that estimates the fraction of the CEC CED load for their respective Forecast Areas.
cec_iepr_2015/ **_dem_inputs.csv	For each IOU, one of these files exists that contains the demographic data associated with the CEC CED Medium Demand forecast.
end_use_penetrations/ cec_ev_forecast.csv	Statewide EV forecast, with a row for each year and columns: bev_cec_high, phev_cec_high, bev_cec_low, phev_cec_low, bev_cec_med, phev_cec_med. This data was processed from the CEC 2014-2024 forecast, and estimates the number of vehicles in California for a set of years.
ev_intermediate/ slap_sector_disaggregation.csv	Defines the proportions of EVs that belong in each SLAP. Has a row for each SLAP and four value columns: res_phev, com_phev, res_bev, and com_bev. Therefore, sum of res_phev and com_phev columns should equal 1, as should the sum of res_bev and com_bev columns.
ev_intermediate/ single_ev_profiles.csv	Contains 8760 demand profiles for an individual electric vehicle of six types: residential bev and phev, commercially-owned bev and phev, and residentially-owned bev and phev charging at a workplace. This data is processed estimates from LBNL's V2G-Sim model.



A load forecasting diagram illustrates the input files, forecasting process, and cluster level outputs:

Further detail about how these data sources interact and the results

that are available tend to dwell on the actual model and modeling details. The data sources, however, which include for example storage and EV modeling, seem very useful for all segments of the DER community.

Data access matrix

The following matrix include all inputs to the data access matrix to-date by WG members. The entries have not been edited.

Stakeholder Category	Function Requiring Data	Rationale for Function	Data Types Required	Rationale for Data Type	Confidentiality Issues	Availability of Data	Alternative Data Sources
<b>Who wants the data?</b>	<b>What is the stakeholder trying to accomplish?</b>	<b>Why does the stakeholder need to perform this function?</b>	<b>What Data Types are necessary to perform the function?*</b>	<b>Why these Data Type(s) are required to perform the function?</b>	<b>For example: Customer confidential, Market Sensitive, Critical Energy Infrastructure Information (CEII)</b>	<b>Is there high cost or burden to provide this data?</b>	<b>For example, anonymized data, aggregated data, public sources?</b>
Developers	One, maximize locational and temporal values of DERs. Two, maximize flexibility to optimize mixes of DERs to unique needs of local community energy needs.	Mobilize the private capital markets to accelerate the expand DERs deployment. This objective would be accomplished by providing raw data and allowing the markets to make their decisions on how to best invest in DERs that maximize their ROIs. This approach mitigate the risks of being overly reliance the estimates (i.e. assumptions of market choices, operation and	Hourly data of "available capacity to serve" (i.e. nameplate capacity - local node load) for all nodes of all circuits.	Raw hourly data of the "available capacity to serve" would be agnostic to assumptions on the type of DERs might be adopted and how they would be operated and maintained.	None - no customer energy consumption data needed.	Yes, the IOUs should already have these data as part of their ongoing O&M of their local distribution grid networks.	Aggregated energy consumption data at the planning tract level.

LNBA Working Group - Intermediate Status Report on Long-Term LNBA Refinement

		maintenance behaviors of non-utility owned DERs) that may not lead to optimal planning and investment decisions.					
Developers	Siting for maximum locational value	Maximize locational value	CAISO LMPs or deviation of LMP from zonal		None	No	Software exists in the market which maps LMP data to the feeder level using publicly available data, but the software is not freely available. This should be included in LNBA.
DER providers and customers	Properly designing DER solutions for customers	To build a distributed grid, we need to make it easy to construct customer-sited assets that are well suited for the host customer	<p>1. Account elements</p> <ul style="list-style-type: none"> <li>- Account name (ACME Inc. or Joe Smith)</li> <li>- Account address (123 Office St.)</li> <li>- Account ID (2-xxx...)</li> </ul> <p>2. Outage block (A000)</p> <p>3. Service Elements</p> <ul style="list-style-type: none"> <li>- Service ID (3-xxx...)</li> <li>- Service address (123 Main ST. #100...)</li> <li>- Service tariff (D-TOU)</li> <li>- Service tariff options (CARE, FERA, etc.)</li> <li>- Service voltage (if relevant)</li> <li>- Service meter number (if any)</li> <li>- # of service meters</li> <li>- a service account may have multiple meters; is that captured?</li> </ul> <p>4. Historical bills (since beginning of service)</p>	If the customer chooses to have a relationship with a DER provider, the customers wishes should be respected and it should be easy for the provider to perform the needed work on behalf of the customer	The customer's digital signature (including click-through) should be required to authorize data sharing. A third party should not be held to a higher authentication standard than the utility holds itself. Accordingly, the utility will authenticate using consumer-centric login credentials, for example, zip code and account # or	This request is consistent with prior Commission decisions so there may be no additional cost.	

			<p>5. Billing elements</p> <ul style="list-style-type: none"> <li>- bill start date</li> <li>- bill end date</li> <li>- bill total charges (\$)</li> <li>- bill total kWh</li> </ul>		<p>online account username and password. A utility account holder should be allowed to begin and end the clickthrough process on the third party website. This may happen without any requirement to log in to any other site/process during this flow (e.g. checkbox) or may allow the user to remain in the third party website flow, even in various authentication scenarios (login, signup, forgotten password, etc.) as in the case of OAuth or open authorization protocols. The click-through process should be designed to be one-click and the third party may lead the customer request for the types of data and the</p>	
			<p>6. Bill tier breakdown (if any)</p> <ul style="list-style-type: none"> <li>- Name (over baseline 1%-30%)</li> </ul>			
			<p>7. Bill TOU kWh breakdown (if any)</p> <ul style="list-style-type: none"> <li>- Name (summer off-peak)</li> <li>- Volume (1234.2)</li> <li>- Cost (\$100.23)</li> </ul>			
			<p>8. Bill demand breakdown (if any)</p> <ul style="list-style-type: none"> <li>- Name (summer max demand)</li> <li>- Volume (1234.2)</li> <li>- Cost (\$100.23)</li> </ul>			
			<p>9. Bill line items (sum should equal bill total charges above)</p> <ul style="list-style-type: none"> <li>- Charge name (DWR bond charge)</li> <li>- Volume (1234.2)</li> <li>- Unit (kWh)</li> <li>- Rate (\$0.032/kWh, if any)</li> <li>- Cost (\$100.23, if any)</li> </ul>			
			<p>10. NEM/tracked line items</p> <ul style="list-style-type: none"> <li>- Charge name (E.g., net in/net out)</li> <li>- Volume (1234.2)</li> <li>- Unit (kWh)</li> <li>- Rate (\$0.032/kWh, if any)</li> <li>- Cost (\$100.23, if any)</li> </ul>			
			<p>11. Payment information</p>			
			<p>12. Historical intervals (since beginning of service)</p> <ul style="list-style-type: none"> <li>- Start (unix timestamp)</li> <li>- Duration (seconds)</li> <li>- Volume (1234.2)</li> <li>- Unit (kWh)</li> </ul>			
			<p>Ideally also: capacity reservation level (CRL) for CPP/PDP customers, demand response program</p>			

LNBA Working Group - Intermediate Status Report on Long-Term LNBA Refinement

			name and nomination, if fixed, standby reservation if a customer has on-site generation, and sublap for wholesale nomination		time frame of data sharing. The customer may approve or reject such a request in its sole discretion.		
Software developer/DER developer	Automated analysis of DER solutions for given property.	Assess impacts of alternative solutions on grid as means of optimizing the solution and preparing data for Interconnection request	Data required in form of API or downloadable/queryable dataset. See "data requests" in companion document - John Carney	in order to (1) reduce costs of individual solar installs, and (2) expedite Interconnection, we need programmatic access to ICA data	CEEI - potential risk so can be addressed with allowing access to only authorized recipients. API is best path to secure. Download data creates Broader security risk in protecting replication of data set. There is no customer specific data (other than being able to map a meterID to a geographic location) - actual meter data can be added via existing Green Button process	Most data already exists. Costs are associated with (1) making data available; (2) ensuring security of data; (3) filling missing gaps in data; (4) setting common formats across IOUs	Manually fetch data through IOU graphical tools . Graphical tools are important, but don't address scale and cost reduction for DER deployments
Software Developer ( Vendor to IOU, DER Developer)	Automated analysis of geographic region to identify optimal targets for DER	Assess geographic areas to identify optimal target locations will (1) accelerate the deployment of DER and (2) allow DER development	Data required in form of API or downloadable/queryable dataset. See "data requests" in companion document - John Carney	in order to (1) reduce costs of individual solar installs, and (2) expedite Interconnection, we need programmatic access to ICA data	CEEI - potential risk so can be addressed with allowing access to only authorized recipients. API is best path to secure. Download data creates	Most data already exists. Costs are associated with (1) making data available; (2) ensuring security of data; (3) filling missing gaps in data; (4) setting	None? - Graphical tools do not support area analysis

LNBA Working Group - Intermediate Status Report on Long-Term LNBA Refinement

		to focus on areas most beneficial to the grid/IOU			Broader security risk in protecting replication of data set. There is no customer specific data (other than being able to map a meterID to a geographic location) - actual meter data can be added via existing Green Button process	common formats across IOUs	
Software Developer ( Vendor to IOU)	IOU Tools for internal and external access to ICA data (e.g. PGE&E RAM)	providing programmatic access to data, with common formats across IOUs will allow third parties to create tools for the IOUs. This will give the IOU a choice of building their own tools or leveraging a third party who can split their costs across multiple IOUs	Data required in form of API or downloadable/ queryable dataset. See "data requests" in companion document - John Carney + GIS + potentially broader grid data for internal and external tools development incorporating ICA data	IOUs will have option of outsourcing standard tool development (or creating shared source projects) and thus cut internal IT costs	None. This would be tools developed for IOU where IOU set access authorization	No. While there is initial costs to standardize, the long term costs are reduced by leveraging vendors and/or shared source development	Each IOU builds their own tools
Software Developer ( DER Developer)	IOU Tools for internal and external access to ICA data (e.g. PGE&E RAM)	providing programmatic access to data, with common formats across IOUs will allow third parties to create tools for the IOUs. This will give the IOU a choice	Data required in form of API or downloadable/ queryable dataset. See "data requests" in companion document - John Carney + GIS + potentially broader grid data for internal and external tools development incorporating ICA data	IOUs will have option of outsourcing standard tool development (or creating shared source projects) and thus cut internal IT costs	None. This would be tools developed for IOU where IOU set access authorization	No. While there is initial costs to standardize, the long term costs are reduced by leveraging vendors and/or shared source development	Each IOU builds their own tools.

LNBA Working Group - Intermediate Status Report on Long-Term LNBA Refinement

		of building their own tools or leveraging a third party who can split their costs across multiple IOUs					
Software Developer (DER Developer or vendor to DER developer)	Meter data access for customer with demand greater than 250kw *not clear if this is an issue across all IOUs	meter data access exists via Green Button; however, for larger customers it seems that the meter history data may be move to different system and thus not available through Green Button APIs	<a href="#">existing Green Button data formats</a>	in order to (1) reduce costs of individual solar installs, and (2) expedite Interconnection, we need programmatic access to ICA data + same reason to get Green Button data for < 250kw demand sites. DER feasibility, financial modeling, NEM and interconnection impact calculations	Already addressed by the existing Green Button authorization process	No. Data exists. Just seems to be unavailable for larger customers.	Have larger customers manually download their meter history
Software developer (vendor to IOU, non-profit) Potentially also DER developer and/or vendor to DER developer	Meter data access by defined geographic region w/ individual customer access per meter - (see confidentiality note for alternative to IOU vendor use)	Deeper analysis of given region to not only account for optimal DER site targeting based on grid data but to also incorporate load data (potential localized DER consumption	Data required in form of API or downloadable/queryable dataset. *See "data requests" in companion document	in order to (1) reduce costs of individual solar installs, and (2) expedite Interconnection, we need programmatic access to ICA data - adding meter history data would allow more advanced modeling for target site targeting	CEEI + confidential customer meter history data. Needs discussion as to limiting access to Vendor developed tools that (1) are only accessible by IOU (data used internally); (2) potential non-profit access for studies/reports; (3) potential 3rd	Costs associated with (1) bulk fetch of meter history data; (2) security of data; (3) alternative solution for external vendors requires work to perform optimal targeting internal to IOU (potentially via 3rd party developer	Get individual Green Button approvals for all meters in a given geographic region - (not viable)

LNBA Working Group - Intermediate Status Report on Long-Term LNBA Refinement

					party use if can find acceptable method for disclosing higher level data to approved vendors; (4) perhaps IOU only using the data internally to then expose ranked line segments for a given region - where rank values are related to optimal targeting (thus not needing to expose meter data specifically)	provided tool) to publish ranked list of line segment related to optimal targeting	
Software Developer ( Vendor to IOU, Non-Profit) Potentially also DER developer and/or vendor to DER developer	Substation Net Load analysis	Assess impacts to substation net load balancing of proposed and planned DER installations. Also a component of geographic region analysis to selecting optimal site targets for DER	Given Substation, provide list of feeders and historical load profiles across feeders As well as indication of connected feeders	in order to (1) reduce costs of individual solar installs, and (2) expedite Interconnection, we need programmatic access to ICA data	CEEI - potential risk so can be addressed with allowing access to only authorized recipients. API is best path to secure. Download data creates Broader security risk in protecting replication of data set. There is no customer specific data	unknown	Alternative could be to sum up all of the demand on a given feeder but this requires then to have individual meter data (a customer privacy concern) for all meters on the feeder. This also does not solve the need to identify connected feeders

LNBA Working Group - Intermediate Status Report on Long-Term LNBA Refinement

<p>Software Developer ( DER Developer vendors to DER Developers)</p>	<p>Interconnection</p>	<p>Automation of Interconnection request submittal - standard across ISO - makes sure all required data is provided in standardized for Also potentially specific data related to target line segment regarding approval consideration</p>	<p>in order to (1) reduce costs of individual solar installs, and (2) expedite Interconnection</p>	<p>in order to (1) reduce costs of individual solar installs, and (2) expedite Interconnection</p>	<p>None - this is submission of data originated from 3rd party</p>	<p>Cost is minimal and includes supporting API interface for Interconnection approval request</p>	<p>Manual form and manual web-based entry forms</p>
<p>Software Developer ( DER Developer vendors to DER Developers)</p>	<p>Interconnection Workflow</p>	<p>Automate workflow associated with Interconnection approval process</p>	<p>Data related to status of Interconnection approval status: submitted, pending, awaiting particular response/data, complete, etc.</p>	<p>in order to (1) reduce costs of individual solar installs, and (2) expedite Interconnection</p>	<p>Confidentiality between IOU and DER Developer. Note that many cities make the Permit process public. Perhaps Interconnection process (or partial data related to approval) could be public also - given city permit may be public anyway.</p>	<p>Costs related to work flow engine integration and exposure of API along with associated security</p>	<p>Manual Interconnection status tracking. Web GUI query interfaces provided by IOU - which may differ per IOU.</p>

LNBA Working Group - Intermediate Status Report on Long-Term LNBA Refinement

<p>DER providers, including software companies</p>	<p>To provide end customers with accurate project economics, including bill savings amount as a result of DER</p>	<p>In the sales process, DER providers estimate the economics for the customer relative to traditional utility service. Since rates are increasingly complex (TOU, demand charges, nonbypassable charges, etc.), it becomes impossible for DER providers to accurately model ALL rates for ALL utilities across the U.S.</p>	<p>All details of Commission-approved rates should be published in a central location (i.e. NREL's Utility Rate Database) and kept up to date by each utility.</p>	<p>Rate information can be obtained from the PDFs of Commission-approved schedules, but it is extremely difficult for a human to reproduce a bill from this PDF. A machine-readable, standardized format solves this problem.</p>	<p>None - rates are already public.</p>	<p>Quite small, since IOU billing systems already have rate information. It just needs to be published consistently and kept up to date by each IOU.</p>	<p>Each DER has to manually parse each utility's rates (50,000+ across the U.S.)</p>
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APPENDIX B: Meeting Summaries

In its facilitator role, More than Smart publicly documented all meetings online at <http://drpwg.org/sample-page/drp/> with requests for WG input.

Meeting summaries, participation lists, submitted stakeholder comments, and audio or webinar information when available, can be found at:

Meeting Date	Topic(s)
May 12 – 1:00pm-3:00pm Webinar (combined ICA/LNBA WG webinar)	<b>Opening meeting</b> Presentation: <a href="http://drpwg.org/wp-content/uploads/2016/05/R1408013-Joint-WGs-kick-off-deck-presentation-0512162.pptx">http://drpwg.org/wp-content/uploads/2016/05/R1408013-Joint-WGs-kick-off-deck-presentation-0512162.pptx</a> Recording: <a href="#">click here</a>
June 1- 9:00am-3:00pm In person (combined ICA/LNBA WG meeting)	<b>First discussion of demonstration implementation plan before June 16<sup>th</sup> submission</b> Presentation: <a href="http://drpwg.org/wp-content/uploads/2016/05/6.1.16-LNBA-meeting.pptx">http://drpwg.org/wp-content/uploads/2016/05/6.1.16-LNBA-meeting.pptx</a>
June 9 – 9:00am-3:30pm In person (combined ICA/LNBA WG meeting)	<b>Second discussion of demonstration implementation plan before June 16<sup>th</sup> submission</b> Presentation: <a href="http://drpwg.org/wp-content/uploads/2016/05/6.9.16-LNBA-meeting-final.pptx">http://drpwg.org/wp-content/uploads/2016/05/6.9.16-LNBA-meeting-final.pptx</a> Meeting notes: <a href="http://drpwg.org/wp-content/uploads/2016/06/LNBA-WG-High-Level-Summary-06092016.docx">http://drpwg.org/wp-content/uploads/2016/06/LNBA-WG-High-Level-Summary-06092016.docx</a> Participant list: <a href="http://drpwg.org/wp-content/uploads/2016/06/ICA-and-LBNA-Working-Group-Participation-List-060916.pdf">http://drpwg.org/wp-content/uploads/2016/06/ICA-and-LBNA-Working-Group-Participation-List-060916.pdf</a> Recording: <a href="#">click here</a>
July 5 – 2:00pm-4:00pm Conference call, combined ICA/LNBA WG call)	<b>Call to discuss submission of IOU demonstration implementation plan</b>
July 26 – 9:00am-4:00pm In person	<b>Discussion of submitted stakeholder comments on demonstration implementation plans, use cases (focusing on procurement use case), grid services (6.2.b), E3 methodology, and data &amp; maps (6.1.a)</b> Presentation: <a href="http://drpwg.org/wp-content/uploads/2016/07/LNBA-Working-Group-072616_FINALVERSION.pptx">http://drpwg.org/wp-content/uploads/2016/07/LNBA-Working-Group-072616_FINALVERSION.pptx</a> Meeting notes: <a href="http://drpwg.org/wp-content/uploads/2016/07/July-high-level-notes-ICA-LNBA.docx">http://drpwg.org/wp-content/uploads/2016/07/July-high-level-notes-ICA-LNBA.docx</a> Participant list: <a href="http://drpwg.org/wp-content/uploads/2016/07/July-LBNA-Working-Group-Participation-List.pdf">http://drpwg.org/wp-content/uploads/2016/07/July-LBNA-Working-Group-Participation-List.pdf</a> Stakeholder comments submitted to IOU demonstration implementation plans: <ul style="list-style-type: none"> <li>• <a href="#">VoteSolar</a></li> <li>• <a href="#">ORA</a></li> </ul>

	<ul style="list-style-type: none"> <li>• <a href="#">IREC</a></li> <li>• <a href="#">SolarCity</a></li> </ul>
<p>August 31 – 9:00am – 4:15pm In person (combined ICA/LNBA WG meeting)</p>	<p><b>Clarification on use cases, Initial scoping discussion on long-term refinement issues (6.2.1A-D), and initial data discussion</b></p> <p>Presentations: <a href="http://drpwwg.org/wp-content/uploads/2016/07/ICAandLNBA_August31_V2-1.pdf">http://drpwwg.org/wp-content/uploads/2016/07/ICAandLNBA_August31_V2-1.pdf</a></p> <p>Meeting notes: <a href="http://drpwwg.org/wp-content/uploads/2016/07/August-high-level-notes_v2.docx">http://drpwwg.org/wp-content/uploads/2016/07/August-high-level-notes_v2.docx</a></p> <p>Participant list: <a href="http://drpwwg.org/wp-content/uploads/2016/07/August-LNBA-WG-Meeting-Participant-List.pdf">http://drpwwg.org/wp-content/uploads/2016/07/August-LNBA-WG-Meeting-Participant-List.pdf</a></p> <p>Data:</p> <ul style="list-style-type: none"> <li>- Draft scoping document: <a href="http://drpwwg.org/wp-content/uploads/2016/07/Data_Draft_9Sept2016.docx">http://drpwwg.org/wp-content/uploads/2016/07/Data_Draft_9Sept2016.docx</a></li> <li>- Data access template: <a href="http://drpwwg.org/wp-content/uploads/2016/07/Template-for-Data-Access-needs_9.23.docx">http://drpwwg.org/wp-content/uploads/2016/07/Template-for-Data-Access-needs_9.23.docx</a></li> <li>- Stakeholder comments: <ul style="list-style-type: none"> <li>o <a href="#">EDF</a></li> </ul> </li> </ul> <p>Long-term refinement scoping documents:</p> <ul style="list-style-type: none"> <li>- 6.2.1.a: <a href="http://drpwwg.org/wp-content/uploads/2016/07/LNBA-long-term-refinement-scope-Topic-A-2016.09.13.docx">http://drpwwg.org/wp-content/uploads/2016/07/LNBA-long-term-refinement-scope-Topic-A-2016.09.13.docx</a></li> <li>- 6.2.1.b: <a href="http://drpwwg.org/wp-content/uploads/2016/07/LNBAWGLongTermRefinementB_rev-5.docx">http://drpwwg.org/wp-content/uploads/2016/07/LNBAWGLongTermRefinementB_rev-5.docx</a></li> <li>- 6.2.1.c: <a href="http://drpwwg.org/wp-content/uploads/2016/07/LNBA-MarginalCostPlan-draft_10.31.docx">http://drpwwg.org/wp-content/uploads/2016/07/LNBA-MarginalCostPlan-draft_10.31.docx</a></li> <li>- 6.2.1.d: <a href="http://drpwwg.org/wp-content/uploads/2016/07/LNBA-methodology-6-2-1D-DER-in-concert_final.docx">http://drpwwg.org/wp-content/uploads/2016/07/LNBA-methodology-6-2-1D-DER-in-concert_final.docx</a></li> </ul> <p>Recording: <a href="#">click here</a></p>
<p>September 30 – 9:00am-4:00pm In person (combined ICA/LNBA WG meeting)</p>	<p><b>Demo B status update, data access discussion</b></p> <p>Presentation: <a href="http://drpwwg.org/wp-content/uploads/2016/07/ICAandLNBA_September30tb.pptx">http://drpwwg.org/wp-content/uploads/2016/07/ICAandLNBA_September30tb.pptx</a></p> <p>Meeting notes: <a href="http://drpwwg.org/wp-content/uploads/2016/07/September-ICA-LNBA-meeting-summary_draft.docx">http://drpwwg.org/wp-content/uploads/2016/07/September-ICA-LNBA-meeting-summary_draft.docx</a></p> <p>Participant list: <a href="http://drpwwg.org/wp-content/uploads/2016/07/September-ICA-LNBA-Working-Group-meeting-participant-list-1.pdf">http://drpwwg.org/wp-content/uploads/2016/07/September-ICA-LNBA-Working-Group-meeting-participant-list-1.pdf</a></p>
<p>October 19 - 9am-12:30pm (webinar)</p>	<p><b>Second scoping discussion on long-term refinement issues (6.2.1 A-D)</b></p> <p>Presentation: <a href="http://drpwwg.org/wp-content/uploads/2016/07/October-LNBA-slide-deck.pptx">http://drpwwg.org/wp-content/uploads/2016/07/October-LNBA-slide-deck.pptx</a></p> <p>Meeting summary: <a href="http://drpwwg.org/wp-content/uploads/2016/07/October-LNBA-meeting-summary_draft_10.26.docx">http://drpwwg.org/wp-content/uploads/2016/07/October-LNBA-meeting-summary_draft_10.26.docx</a></p> <p>Participant list: <a href="http://drpwwg.org/wp-content/uploads/2016/07/October-LNBA-Participant-List.docx">http://drpwwg.org/wp-content/uploads/2016/07/October-LNBA-Participant-List.docx</a></p> <p>Recording: <a href="#">click here</a></p>
<p>October 27 – 12:30pm-2:30pm (webinar)</p>	<p><b>Grid services and project deferability criteria</b></p> <p>Presentation: <a href="http://drpwwg.org/wp-content/uploads/2016/07/20161026-LNBA-Deferral-Discussion-v5-final.pdf">http://drpwwg.org/wp-content/uploads/2016/07/20161026-LNBA-Deferral-Discussion-v5-final.pdf</a></p>

	<p>Stakeholder comments:</p> <ul style="list-style-type: none"><li>• <a href="#">EDF</a></li></ul> <p>Participant list: <a href="http://drpwg.org/wp-content/uploads/2016/07/October-27-Participant-List.xlsx">http://drpwg.org/wp-content/uploads/2016/07/October-27-Participant-List.xlsx</a></p> <p>Recording: <a href="#">click here</a></p>