Locational Net Benefit Analysis Working Group - Group I Interim Status Report

Prepared for the LNBA Working Group by More Than Smart on August 31, 2017

Background:

A June 7, 2017 Assigned Commissioner Ruling (ACR) set a scope and schedule[1] for continued long-term refinement (LTR) discussions on both Integrated Capacity Analysis (ICA) and Locational Net Benefit Analysis (LNBA). This ACR includes pre-Working Group (WG) deliverables, status reporting, and final reporting milestones for continued long-term refinement discussions. The ACR groups the identified long-term refinement topics into three groups and front-loads work on topics of relatively high complexity and/or importance to the further development of LNBA. The Group I topics are as follows:

Topic	**June 7 ACR Item**
1. Methods for valuing location-specific grid services provided by advanced smart inverter capabilities (*WG proposes to streamline and combine with 2iii)*	ACR – B
2. Method for evaluating the effect on avoided cost of distributed energy resources (DER) working “in concert” in the same electrical footprint of a substation (*same as 2ii*)	ACR – D
3. Improve heat map and spreadsheet tool by: i) Including options to automatically populate DER generation profile input *ii)* Enabling modeling of a portfolio of DER projects at numerous nodes to respond to a single grid need *(same as D)* iii) Allowing hourly VAR profiles to be input in order to capture DERS’ ability to inject or absorb reactive power (*WG proposes to combine with B*)	WG - 2
4. Incorporate additional locational granularity into energy, capacity, and line losses system-level avoided cost values	WG – 4
5. Form technical subgroup in LT refinements to develop methodologies for non-zero location-specific transmission costs (requires coordination/co-facilitation with CAISO)	WG – 5

The Working Group has met twice since the release of the ACR. The meeting notes, webinar recordings, participant lists, and slides from those meetings are included as links in the Appendix of this status report. The technical subgroup on location-specific transmission costs has met four times via conference call. The meeting material from those calls is also included in Appendix A of this status report.

The Working Group established a consensus method for discussing topics, developing written proposals, and receiving edits or comments on those proposals. These are detailed in the proposal document, found here[2]**.** This interim status report identifies which parties have submitted proposals, which parties have submitted comments, and summarizes WG discussion and next-steps in Appendix B. These proposals reflect the main work products of the WG to date, incorporates feedback and comments made during the in-person monthly meetings, and assists the WG in developing its final WG report due January 2018.

[1] http://drpwg.org/wp-content/uploads/2016/07/189819375_ACR_06.08.17.pdf
[2] http://drpwg.org/wp-content/uploads/2016/07/High-Level-ICA-LNBA-LT-Refinements-WG-Project-Plan-v.6.29.docx

1. Methods for valuing location-specific grid service provided by advanced smart inverter capabilities (Item B)/ Allowing hourly VAR profiles to be input in order to capture DERS' ability to inject or absorb reactive power (Item 2iii)

Background: This topic was initially discussed in July and then presented in full at the August meeting. The LNBA WG discussed collapsing Item B and Item 2.iii, as DERS use smart inverters to provide reactive power. Item 2iii was indicated to be a priority item under the ACR, while additional smart inverter capabilities will be addressed in future meetings after VAR profiles are discussed.

Initial proposal(s): The joint IOUs presented a proposal to incorporate VAR profiles. SEIA and Tesla proposed to include conservation voltage reduction (CVR) as a smart inverter functionality in the LNBA.
Joint IOU proposal[3]: To incorporate VAR profiles into the tool, the IOUs propose to add a tab for an hourly VAR profile along with the current hourly active power input within the spreadsheet. Then a VAR requirements profile is added to validate that the DER VAR profile input meets or exceeds the requirement profile. The IOUs propose to develop a methodology to calculate hourly VAR requirement profile. Several requirements in Rule 21 under consideration, such as reactive power requirements, power factor limits and assumptions, will influence the development of VAR profiles.
Joint SEIA and Tesla proposal[4]: SEIA and Tesla submitted a joint proposal to create a locational value for CVR benefits that can be realized through utilities' existing CVR schemes when DERs are available at the low-voltage customers on a distribution circuit, typically at the end of a circuit. Tesla and SEIA propose to calculate the CVR benefit in the form of reduced energy consumption and capacity reductions, much the same way benefits are quantified for other energy savings programs. The energy conservation benefit would be calculated by using a CVR factor to convert voltage reduction to energy savings using standard CVR factors for typical customer types.

Edits and comments:

- No additional comments were submitted with regards to the joint IOU VAR profiles proposal.
- TURN[5] and the joint IOUs[6] both submitted comments on the SEIA/Tesla CVR proposal. TURN comments that, within the LNBA, any avoided cost or benefit included in the tool must be captured by all ratepayers, and the inclusion of CVR does not meet this principle. The joint IOUs comment that the proposal assumes a system-wide value for CVR, though the capabilities relies upon deployment of smart inverters in specific locations and quantities. The IOUs don't currently have necessary control capabilities to manage voltage regulating equipment to enable CVR benefits. Finally, the IOUs comment that the method calculating CVR benefits based on customer bill savings rather than utility avoided cost is incorrect.

Next steps:

- The joint IOUs will modify the tool and begin development of methodology to calculate hourly VAR requirement profile. The WG will revisit non-priority smart inverter functionality topics.

[3] http://drpwg.org/wp-content/uploads/2016/07/LNBA-Item-2iiiandB-VAR-profile_Rev-1.docx
[4] http://drpwg.org/wp-content/uploads/2016/07/LNBA-Item-4-Tesla_SEIA_Conservation_Voltage_Reduction-22AUG17.docx
[5] http://drpwg.org/wp-content/uploads/2016/07/TURN-Comments-on-Tesla-and-SEIA-Proposal-for-an-Avoided-Cost-Value-Related-to-Conservation-Voltage-Reduction.docx
[6] http://drpwg.org/wp-content/uploads/2016/07/LNBA-Conservation-Voltage-Reduction-IOU-Comments_Final.docx

2. Method for evaluating the effect on avoided cost of DER working "in concert" in the same electrical footprint of a substation/enabling modeling of a portfolio of DER projects at numerous nodes to respond to a single grid need

Background: This item was presented at the July meeting. The ACR indicates that items D in the ACR and Item 2ii should be considered the same topics.

Initial proposal(s): The joint IOUs proposed[7] to modify the spreadsheet tool to enable multiple DERs to be aggregated, so they can be modeled as solutions to a single need. This is done by adding additional columns to the User Input DER Profile Section on the DER dashboard tab, so users may input separate DER profiles and locations to create appropriate portfolios. The IOUs propose to create a DER profile library (see 2i) so that users do not have to manually input profiles. Each column will also have a cell to help scale the profile up or down, to allow any size DER to be analyzed. The columns will aggregate into one existing DER profile column on the DER dashboard tab to analyze overall financial impact of all DERs combined.

Edits and comments: No comments were submitted.

Next steps: There was general agreement during the July meeting that this approach meets the ACR requirement. No written comments were submitted. The IOUs will work on this tool modification implementation.

[7] http://drpwg.org/wp-content/uploads/2016/07/LNBA-Item-2.ii-Multiple-projects-to-meet-single-need.docx

3. Improve heat map and spreadsheet tool by i) including options to automatically populate DER generation profile input

Background: This topic was addressed at the July meeting. The WG is in consensus that the LNBA tool should include illustrative DER generation profiles rather than requiring users to manually input their own profiles.

Initial proposal(s): The joint IOUs proposed[8] to create a DER profile library that includes a reasonable amount of normalized profiles of common DER types. The profiles will be normalized to 1 kW which would facilitate the scaling of the selected DER profile by a user inputted size. The DER profile library would be included in the updated LNBA Tool. The IOUs propose the use of publicly available resources (NREL PVWAtts Calculator for typical solar profiles and E3's Energy Efficiency calculator for typical energy efficiency profiles). For other DERs, stakeholders are encouraged to submit additional typical hourly DER profiles to be included in the tool, ideally using publicly available and vetted data sources.

Edits and comments: No comments were submitted.

Next steps: Stakeholders are welcome to propose additional typical hourly DER profiles to be included in the DER profile library. Joint IOUs will add the two identified profiles for solar and EE to the tool.

[8] http://drpwg.org/wp-content/uploads/2016/07/LNBA-Item-2.i-DER-Shapes.docx

4. Incorporate additional locational granularity into energy, capacity, and line losses system-level avoided cost values

Background: The WG discussed energy and capacity values at the July meeting, and discussed the line losses proposal during the August meeting.

Initial proposal(s):

- **Energy[9]:** the joint IOUs propose to use the DLAP price forecast associated with each IOU to replace the system-wide avoided energy forecast currently used, to evaluate the suitability of existing public DLAP forecasts and to develop a methodology to forecast DLAP prices for use in the LNBA tool.
- **Capacity[10]:** The joint IOUs propose to develop location-specific avoided cost values at the CPUC's Local RA areas, based on the CAISO LCR are level. Areas outside of a local RA area would receive a system-level generation capacity avoided cost. Avoided cost is determined using local RA multiples applied to a system-level forecast. All generation capacity prices are capped at the net CONE for that year. If the system-level price forecast reaches CONE, all other areas are also set at CONE.
- **Line losses[11]:** The joint IOUs propose to evaluate distribution primary losses in a more detailed circuit modeling exercise to determine the effect of DER location on distribution circuit losses, how loss factors should be included in the LNBA and whether the IOUs should pursue a more granular, location-specific methodology. The joint IOUs will also evaluate secondary system losses.

Edits and comments:

- **Energy:** No additional comments were submitted by WG members.
- **Capacity:** SEIA[12] proposed that the avoided cost value should instead be based on IOU-specific, loss-adjusted CONE values for each IOU service territory, as the CPUC RA report is only based on voluntary responses. Loss adjustments should be based on peak period line losses in each service territory from generation level to load level. These IOU-specific CONE values would reflect locational differences due to (1) differences in peak period losses in each IOU service territory and (2) different CONE calculations given variations in CONE between service territories due to different siting costs, energy costs, environmental costs, or the base cost of the marginal source of capacity.
- **Line losses:** Clean Coalition[13] submitted comments clarifying whether it is the IOU service territory or the CAISO-defined transmission area to consider when evaluating transmission line losses.

Next steps:

- **Energy:** After the IOUs conduct their evaluation of existing public DLAP forecasts and develop methodology to forecast prices, the WG will review results at a later meeting date.
- **Capacity:** The WG will consider submitted written comments and address at a future meeting.
- **Line losses:** The joint IOUS will conduct a preliminary study of line loss variation to determine whether line losses are a significant-enough factor to warrant further study, and to what degree of accuracy. This study will be presented at the November WG meeting.

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[9] http://drpwg.org/wp-content/uploads/2016/07/LNBA-Item-4.i-Locational-Avoided-Energy.docx
[10] http://drpwg.org/wp-content/uploads/2016/07/LNBA-Item-4-GenCapacity_Rev-3_1.docx
[11] http://drpwg.org/wp-content/uploads/2016/07/LNBA-Item-4-Line-loss-LT-Refinement-write-up.docx
[12] http://drpwg.org/wp-content/uploads/2016/07/LNBA-Item-4-GenCapacity_Rev-3_1-2-SEIA-clean-FINAL.docx
[13] http://drpwg.org/wp-content/uploads/2016/07/LNBA-Item-4-Line-loss-LT-Refinement-write-up-Clean-Coalition-edits.docx

5. Form technical subgroup (with CAISO) in long-term refinements to develop methodologies for non-zero location-specific transmission costs

Background: A subgroup of the LNBA WG has met bi-monthly since July 19th to discuss methodology options to reflect location-specific transmission costs. These bi-weekly conference calls have been used to tee up initial discussions of potential methodology proposals. The subgroup has agreed to discuss all proposals on the table until September 15.

Initial proposal(s): CPUC Energy Division presented expectations for the subgroup and a default straw proposal to discuss if the subgroup process does not result in a methodology proposal. The subgroup has discussed three starting proposals in brief from the joint IOUs, Clean Coalition, and SEIA, which are summarized below.

- **Energy Division straw proposal:** The Energy Division indicated that it would take responsibility of developing a default straw proposal if the group could not develop a means to reflect location-specific avoided costs within the LNBA. The draft default proposal would calculate marginal transmission costs for distribution system areas that would be served by either 1) load growth-related transmission line sections identified in the TPP; or 2) deferrable transmission projects identified by the method PG&E employs in its GRC Phase 2 testimony.
- **Joint IOUs:** the joint IOUs first presented a set of key principles for how marginal transmission capacity cost is calculated in GRCs, and went into detail on how that is currently done. They then presented an alternative proposal using two approaches, one complex and the other simplified. These methodologies begin with the identified projects in the most recent CAISO transmission plans, deferral screens are applied and RECC values are calculated. For the more complex method, project specific deferral values are calculated for each point of T&D interface for each deferrable project, using power flow analysis. The simple method assigns locational effectiveness at each T&D interface using bucket categories. Project-specific values are summed to find total locational deferral value.
- **Clean Coalition:** CC proposed to use a system-wide value derived from the transmission revenue requirement as a starting point, refined with increased granularity where possible. The locational granularity could be conducted by 1) defining a load area associated with planned projects and assigning each load area a $/mw value for potential deferral; 2) forecasting gross DER load reduction by transmission areas; and 3) assigning marginal avoided transmission costs
- **SEIA:** SEIA proposes to start with system-level marginal CAISO transmission costs and use CAISO LCR studies or utility transmission plans to provide locational granularity in a proposed methodology. SEIA presented on examples of deferred transmission projects, discussed the definition of deferrable transmission used by the IOUs within the GRC process, and presented multiple calculations that may be useful as a starting point.

Edits and comments: Parties have had opportunities to engage in discussion around each of these proposals via the bi-monthly calls but the subgroup has not yet asked for written comments or formal statements of consensus and non-consensus.

Next steps: The subgroup will review any new straw proposals until Sept 15. Moving forward, the subgroup will evaluate proposals in detail, identify points of consensus and non-consensus across all proposals which may assist into merging parts of certain proposals, and identify additional research or analysis which may be needed.

Appendix A: Summary of Meetings

Meeting date	Meeting documents
July 7: LNBA WG	Group I Topics Discussed: - Automatically populate DER generation profile input - Enable modeling of a portfolio of DER projects at numerous nodes to respond to a single grid need - Additional locational granularity into avoided energy - Additional locational granularity into avoided capacity Group I Topics Previewed: - Input of hourly VAR profiles; advanced smart inverter capabilities - Location specific avoided transmission value - Additional locational granularity into line losses Meeting materials: • webinar recording • meeting notes (draft) • slide deck • SEIA updated slide deck • participant list • high level project plan proposal

July 19: LNBA subgroup on avoided transmission	• meeting notes (draft)
	• presentation
	• participant list
	• webinar recording
	• Circulated links and documents:
	    o E3 avoided costs (2016 interim update)
	    o PG&E's 2017 GRC Phase 2 testimony

August 2: LNBA subgroup on avoided transmission	• meeting notes (draft) • participant list • webinar recording • SEIA Avoided CAISO Transmission Presentation to DRP Working Group 2AUG17 • Circulated links and documents: o CEC San Joaquin DER study (2016)
August 15: LNBA WG	Group I Topics Discussed: - Input of hourly VAR profiles; advanced smart inverter capabilities - Location specific avoided transmission value - Additional locational granularity into line losses Meeting materials: • participant list • slide deck • webinar recording
August 16: LNBA subgroup on avoided transmission	• meeting notes (draft) • webinar recording • participant list

	• slide deck
August 30: LNBA subgroup on avoided transmission	• webinar recording • participant list

Appendix B: Written Proposals and Submitted Comments

Topic	June 7 ACR Item	Initial written proposals	Comments
Methods for valuing location-specific grid services provided by advanced smart inverter capabilities (*WG propose to combine with 2iii)*	ACR – B	SEIA and Tesla (conservation voltage reduction)	Joint IOUs TURN
Method for evaluating the effect on avoided cost of DER working "in concert" in the same electrical footprint of a substation (same as 2ii)	ACR – D	See below	
Improve heat map and spreadsheet tool by: i) Including options to automatically populate DER generation profile input ii) Enabling modeling of a portfolio of DER projects at numerous nodes to respond to a single grid need (*same as D)* iii) Allowing hourly Var profiles to be input in order to capture DERS' ability to inject or absorb reactive power (*WG propose to combine with B*)	WG - 2	i) Joint IOUs ii) Joint IOUs iii) Joint IOUs	
Incorporate additional locational granularity into system-level avoided cost values of: i) Energy ii) Capacity iii) Line losses	WG – 4	i) Joint IOUs ii) Joint IOUs iii) Joint IOUs	ii) SEIA iii) Clean Coalition
Form technical subgroup in LT refinements to develop methodologies for non-zero location-specific transmission costs (requires coordination/co-facilitation with CAISO)	WG – 5	Presentation only to-date by CPUC Energy Division, SEIA, Clean Coalition, Joint IOUs	N/A

Item 4: Conservation Voltage Reduction

Tesla and SEIA Initial Proposal

LNBA Working Group

Summary of Recommendations

- SEIA and Tesla propose to create a locational value for Conservation Voltage Reduction(CVR) benefits that can be realized through the utilities' existing CVR schemes when DERs are available at the low-voltage customers on a distribution circuit, typically the end of a circuit.
- Since the 1970s, utilities have employed CVR programs that seek to reduce voltage flowing into distribution circuits where possible in order to conserve energy, reduce costs and avoid construction of generation capacity
- The degree to which voltages can be lowered is limited, however, by the lowest-voltage secondary line on the circuit.
- Deploying solar with smart inverters on buildings located on these lines can increase their voltage, which allows voltages to be lowered on the remainder of the circuit, which has an energy conservation effect
- Tesla and SEIA propose to calculate the CVR benefit in the form of reduced energy consumption and capacity reductions, much the same way benefits are quantified for other energy savings programs. The energy conservation benefit would be calculated by using a CVR factor to convert voltage reduction to energy savings using standard CVR factors for typical customer types on a circuit.

Introduction and Background[14]

As part of their core responsibilities, utilities must supply electricity to customers within established power quality standards. The range of allowable voltages (i.e. 114 to 126 V), an aspect of power quality, is set by American National Standards Institute (ANSI) standards. In practice, utilities over-supply voltage above the median 120v to most customers due to line losses that reduce voltage as electricity flows along distribution circuits. This over-supply of voltage results in excess energy consumption by customers.

To address this voltage delivery inefficiency, utilities are increasingly deploying conservation voltage reduction (CVR) programs. CVR is a demand reduction and energy efficiency technique that flattens and reduces distribution voltage profiles in order to achieve a corresponding reduction in energy consumption and greenhouse gas emissions. A 1% reduction in distribution service voltage can drive a

[14] The description of the benefits of CVR derived from solar and smart inverters described below include selected passages from a longer paper authored by Tesla/SolarCity: http://www.solarcity.com/company/distributed-energy-resources#

0.4% to 1% reduction in energy consumption.[15] CVR programs typically save 0.5 to 4% of energy consumption on individual circuits, and are often implemented on a large portion of a utility's distribution grid.

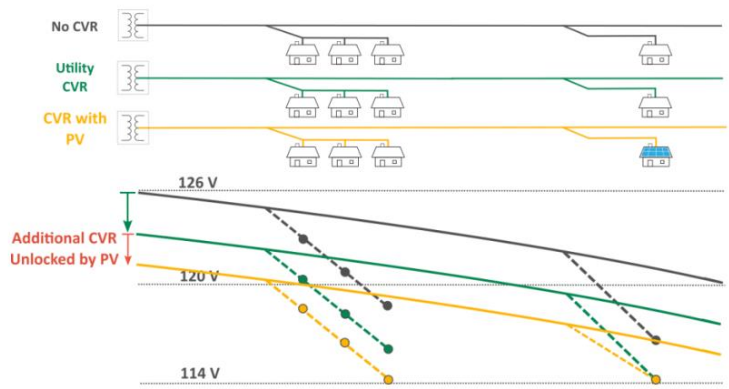
Distributed PV and smart inverters can enable greater savings from utility CVR programs because those programs typically only control utility-owned distribution voltage regulating equipment. Such utility equipment affects all customers downstream of any specific device; therefore, CVR benefits in practice are limited by the lowest customer voltage in any utility voltage regulation zone (often a portion of a distribution circuit) since dropping the voltage any further would violate ANSI voltage standards for that customer. Because distributed PV with smart inverters can increase or decrease the voltage at any individual customer location, these resources can be used to more granularly control customer voltages.

Typical distribution capacity planning studies do not consider the effects of the secondary distribution system, or secondary voltage drop – the portion of the distribution grid consisting of the power lines and pole top transformers that connect a customer's meter to the utility's primary distribution system.[16] However, incorporating these details is critical to capturing the technical potential of CVR since secondary voltage drop is a limiting factor for utility voltage reduction strategies today. Within a voltage regulation zone, if the lowest customer voltages on the secondary distribution system were to be increased by one volt, the entire voltage regulation zone could then be subsequently lowered another volt. Therefore, the benefit of addressing the secondary voltage drop is significant.

The CVR concept is demonstrated in the figure below, where three voltage profiles are shown along a typical distribution circuit, from substation to end customers. The solid lines depict the primary voltage drop, while the dashed lines represent the secondary voltage drop. The reduction in voltage between the gray and green lines represents the voltage reduction that can be achieved solely by controlling utility-owned voltage regulating equipment within a traditional CVR scheme. However, potential voltage reduction is limited by the customer voltage at the end of the line, which in this example is already at the lowest permissible voltage according to ANSI standards. By installing distributed PV with smart inverters at this customer site, the secondary voltage drop is decreased and voltage is subsequently increased, which is evident in the reduced slope of the secondary voltage drop. This allows the overall voltage profile in yellow to be further reduced, increasing efficiency savings.

[15] "Review on Implementation and Assessment of Conservation Voltage Reduction", Wang and Wang, IEEE Transactions on Power Systems, May 2014.

[16] "Evaluation of Conservation Voltage Reduction on a National Level", Schneider, Fuller, Tuffner, and Singh, Pacific Northwest National Laboratory (PNNL) for the US Department of Energy (DOE), July 2010



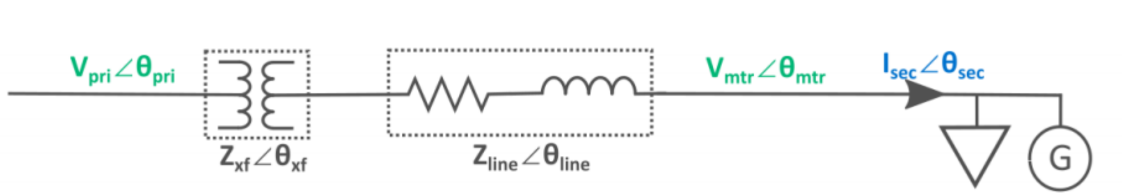
DERs control voltage locally and enable increased CVR benefits

Discussion and Methodology

The following methodology for determining the CVR benefits of distributed PV with smart inverters focuses on inverter contributions at the secondary (low voltage) level. This methodology quantifies the benefit from increasing the voltages of a subset of customers through targeted deployment of distributed PV with smart inverters in order to enable the subsequent decrease of voltages to all other customers on the circuit, resulting in energy efficiency savings. This methodology does not evaluate the incremental benefits to the primary (medium voltage) system due to the complexity introduced in modeling such benefits. Primary system benefits could be modeled if circuit model, equipment, and loading data were available.

Modeling Secondary Voltage Drop

Secondary voltage drop is a function of net load and the impedance of the service transformer and secondary line. To represent a typical secondary system, a simplified secondary model was utilized that consisted of typical pole top transformer, secondary conductor, and customer loads. For simplicity, all load is modeled as connected at a single location at the end of the secondary line. Consistent with the IEEE 8500-Node Test Feeder,[17] the secondary system, and therefore the impedance, consists of a 25 kVA transformer and 50 feet of 4/0 Al secondary conductor. The single line diagram of this typical secondary system is depicted in the figure below.



Single Line Diagram of a Typical Secondary System (All Voltages Referenced to Ground)

Equation 1 below shows how the secondary voltage drop is calculated, which is the difference of voltage magnitude between the primary side of the service transformer and the customer's meter. The voltage at the primary side of the transformer can be derived using the transformer load and secondary impedance, as seen in Equation 2. The voltage at the meter is used as reference and is fixed to a nominal

[17] "The IEEE 8500-Node Test Feeder", Arritt and Dugan, Electric Power Research Institute (EPRI), 2010

value, 120 ∠0° V, as shown in Equation 3. The difference in magnitudes between these two voltages equals the voltage drop across the secondary system (Equation 1).

$$VD = |V_{pri}\angle\theta_{pri}| - |V_{mtr}\angle\theta_{mtr}| \quad (1)$$

Where:

$$V_{pri}\angle\theta_{pri} = \overbrace{(I_{sec}\angle\theta_{sec})}^{Transformer\ Net\ Load} * \overbrace{(Z_{xf}\angle\theta_{xf} + Z_{line}\angle\theta_{line})}^{Secondary\ Impedance} + V_{mtr}\angle\theta_{mtr} \quad (2)$$

$$V_{mtr}\angle\theta_{mtr} = 120\angle 0°\ V \quad (3)$$

Modeling PV with Smart Inverter Capability

The voltage drop reduction of PV with smart inverters is a function of both the underlying PV generation as well as the reactive power capability of the smart inverter. Therefore, their combined impact on the secondary voltage drop must be modeled. To do so, PV production data from the National Renewable Energy Lab's (NREL) PVWatts® Calculator[18] is applied to an archetypal 5 kVA smart inverter. Inverter reactive power capability is activated for all hours of the day, but the smart inverter is assumed to maintain an active power priority because the economic value of active power is generally greater than reactive power (note: in geographies or times of day when reactive power is more valuable, this prioritization can be removed; this is actively being discussed in California). Therefore, the amount of reactive power available per inverter is limited by the coincident apparent power generation. For example, at night when the PV is not generating, the smart inverter is capable of supplying the full 5 kVAr. However, during peak PV generation, the smart inverter maynot be capable of supplying any VArs, depending on the size of the inverter and assuming an active power priority of the inverter. However, since both active and reactive power enable a reduction in secondary voltage drop, any combination of active and reactive power output provides benefits.

A negative secondary voltage drop (i.e. voltage rise) can occur due to reverse power flows from PV back-feeding onto the primary, or excessive reactive power support during low loading conditions. While voltage rises can occur in practice, overall CVR benefits would be limited by the customer with the next lowest voltage. Therefore, secondary voltage drops are assumed to be able to be reduced to zero, but no incremental benefits are attributed to voltage rises on the secondary.

Relating Voltage Reduction to Energy Reduction

Equation 4 details how the incremental CVR energy savings ($/kWh) are calculated for each voltage regulation zone.

$$\left(\frac{\$}{kWh}\right)_{Energy} = \frac{\sum_{t=1}^{8760}\left[\frac{VD_{noPV}-VD_{PV}}{V_{Base}} CVR_f\left(1-\%_{Targeted}\right)E_{RegulationZone}C\right]}{E_{AnnualProducedByPV/Customer}\ \%_{Targeted}\ n_{TotalCustomers}} \quad (4)$$

[18] "NREL's PVWatts® Calculator", National Renewable Energy Lab (NREL), Accessed June 2016. http://pvwatts.nrel.gov

The difference in the secondary voltage drop with and without PV (VDnoPV - VDPV) is calculated for each hour over the course of one year (8760 hours) using Equations 1-3 above. The change in voltage drop after PV is deployed is then converted to a percentage by dividing by the nominal voltage at the customer meter (i.e. 120 V).

The percent reduction in energy for a voltage regulation zone is then determined by multiplying the percent reduction in voltage by the relevant CVR factor. The CVR factor of a load is the change in energy that results from a corresponding change in voltage. For example, if a load has a CVR factor of one, then a 1% reduction in voltage would result in a 1% reduction in energy. A CVR factor of 0.8 has been found to be representative of typical distribution circuits.[19]

Percent reduction in energy for the entire circuit is then determined by multiplying the voltage drop and CVR factor by the percentage of customers that are having their voltage reduced. In this case, the customers who are experiencing the voltage reduction are those without PV installations (1 - %Targeted). Those customers with PV installations will receive the same voltage before and after the CVR scheme is in place, since the PV will raise their voltage while the CVR scheme will then lower it to its previous value. Equation 4 assumes that all customers have the same net load. In other words, 1% of customers consume 1% of the circuit load.

Quantifying Incremental CVR Benefits

After determining the percent reduction in energy, total financial savings in the numerator of Equation 4 are determined by multiplying the percent reduction in energy by the cost of energy in the voltage regulation zone. $/kWh benefits are calculated by dividing this number by the estimated annual energy production from all of the targeted systems. Equation 5 shows an annotated version of the energy benefits calculation highlighting where the change in voltage, reduction in energy, energy costs, and annual energy production are calculated.

$$\left(\frac{\$}{kWh}\right)_{Energy} = \frac{\sum_{t=1}^{8760}\left[\underbrace{\overbrace{\frac{VD_{noPV}-VD_{PV}}{V_{Base}}}^{\text{\% Change in Voltage}} * \; CVR_f\left(1-\%_{Targeted}\right)}_{\text{\% Reduction in Energy due to PV reducing voltage drop}} * \; \overbrace{E_{RegulationZone}C}^{\text{Utility CVR Energy Cost}}\right]}{\underbrace{E_{PV\_AnnualProducedByPVtion/Customer} * \%_{Targeted} * n_{TotalCustomers}}_{\text{Annual Energy Production of all Targeted PV Systems}}} \tag{5}$$

After determining the savings attributed to energy, the savings attributed to capacity can be similarly found by taking the demand reduction at peak and multiplying it by the distribution marginal cost of capacity (DMC) as seen in Equation 6.

[19] "Green Circuit Distribution Efficiency Case Study", Electric Power Research Institute (EPRI), October 2010 PPPhttp://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001023518

$$\left(\frac{\$}{kWh}\right)_{Capacity} = \frac{\left[\frac{VD_{noPV} - VD_{PV}}{V_{Base}} CVR_f \left(1 - \%_{Targeted}\right) P_{RegulationZone} DMC\right]_{At\ Peak\ Load}}{E_{AnnualProducedByPV/Customer}\ \%_{Targeted}\ n_{TotalCustomers}} \quad (6)$$

Total financial savings are determined by adding equations 5 and 6.

$$\left(\frac{\$}{kWh}\right)_{Total} = \left(\frac{\$}{kWh}\right)_{Energy} + \left(\frac{\$}{kWh}\right)_{Capacity}$$

Proposal

There are two potential means of accounting for CVR value in the context of the LNBA and DER Avoided Cost (DERAC) Calculators.

The first option is to represent CVR as a locational value for solar and smart inverter deployment on areas of distribution circuits with the lowest voltage. This value could be represented in the LNBA/ICA maps of the utilities' distribution grids. Value would be calculated by using the formulas above to compute the percentage voltage reduction made possible on a particular circuit by raising the voltage of the lowest-voltage secondary lines. This voltage reduction could then be converted to MWh of energy and MW of capacity saved using a CVR factor and equations 5 and 6 above.

Our understanding is that the utilities lack sufficient understanding of all of their secondary lines to develop this value on a locationally-specific CVR value across their distribution systems. This should not mean, however, that CVR is valued as zero. Thus, in addition to the first option, we propose an alternative method in which averaged CVR value could be integrated into the LNBA and included in instances where CVR is one of the benefits provided by DERs – for example, in the evaluation of a voltage management tariff developed in the Integrated Distributed Energy Resources proceeding.

Conclusion and Next Steps

Solar with smart inverters provide the opportunity for enhanced conservation voltage reduction, which is a powerful energy efficiency strategy for utilities. There are likely multiple ways where DER owners could be provided compensation for providing this service. What is key in the LNBA is to develop a value that ensures that such benefits are accounted for in instances where DERs used to provide CVR. A methodology is available for calculating this locationally, but should the utilities lack the data to calculate this on a locational basis an averaged value can be developed.

The next steps are:

- Create a system-wide CVR value based on an average CVR factor and the avoided energy values in the LNBA tool
- If utilities are able to better understand their secondary lines,, and those can be identified in the LNBA through the maps or spreadsheet tool, CVR should be incorporated as a locational value
- If utilities are not able to identify the low-voltage secondary lines, determine the average contribution of solar PV and smart inverters to CVR in utilities existing CVR programs

LNBA Conservation Voltage Reduction Benefits from Smart Inverters

IOU Response Comments

Introduction

Customers must be provided electrical service within an acceptable voltage range defined in each IOU's Rule 2. If service can be provided at the lower end of the acceptable range, certain end-use devices will consume less real power compared to service at the higher end of the acceptable range. The concept of seeking to provide service at the low end of the acceptable range in order to reduce energy consumption is referred to as Conservation Voltage Reduction (CVR). For purposes of evaluating costs and benefits, and performing cost-effectiveness analysis, CVR should be treated similar to any other energy efficiency measure. CVR is different from the "distribution voltage support" DER service, which is associated with avoiding a voltage-related investment by DERs deferring a voltage upgrade.

From the IOUs' perspective, the SEIA/Tesla proposal inappropriately proposes a simple system-wide value for CVR when this capability is clearly conditioned upon ability to deploy smart inverters in specific locations and quantities. Furthermore, the IOUs do not currently have the needed control capabilities to manage voltage-regulating equipment such that CVR could be enabled using distributed smart inverters. Finally, the proposal improperly suggests calculating CVR benefits that are based on customer bill savings rather than utility avoided cost and refers to a value for smart inverters providing CVR that is mostly attributable to a voltage optimization scheme rather than to the smart inverters themselves.[20] None of the IOUs has comprehensively implemented this voltage optimization scheme which is both necessary to enable smart inverters' ability to provide CVR and also which is responsible for the vast majority of energy savings from CVR.

Existing Conditions (i.e. without smart inverters)

At present, due to the electrical power flow from the substation to our customers on the circuits, generally the voltage reduces from the source substation towards the end of the line (EOL). When voltage is reduced below the required thresholds, the IOUs create mitigation actions to rectify the low voltage conditions. Typically, depending on the severity of the voltage violation, the equipment used for mitigation includes the installation of capacitor banks or voltage regulators.

As such, the IOUs have implemented CVR to varying degrees across their service territories. These management schemes are typically based upon calculations of voltage at the end of line (EOL) customer using impedance data, voltage telemetry at capacitor banks, voltage telemetry at voltage regulators, and substation bus voltage. Through the use of AMI, the IOUs can gather data regarding the EOL voltage. If the voltage at the EOL is higher than anticipated, voltage at the substation bus can be lowered

[20] The SEIA/Tesla proposal references this NREL study of one PG&E feeder: https://www.nrel.gov/docs/fy17osti/67296.pdf. The study finds that for this feeder, voltage optimization accounts for approx. 90% of the observed CVR benefit and smart inverters account for approximately 10%.

further~~,~~ and additional CVR energy savings can be realized assuming substation equipment is capable of making those adjustments.

Enabling CVR Benefits

At the LNBA working group on August 15, 2017, SIEA and Tesla stated that additional CVR energy savings could be enabled through smart inverters connected behind-the-meter if those systems are targeted to the right locations and if the voltage regulating devices on the circuit can be controlled to reduce voltage. This presentation did not discuss additional communication, sensing, or automation required to achieve CVR benefits through smart inverters connected behind the meter on distribution feeders. Specifically, the presenters stated that the only requirement to achieve CVR benefits through smart inverters is for the IOUs to lower the substation voltage. In turn, this would lower the voltage at the beginning of the distribution feeder allowing smart inverters further down the feeder to supply VARs and increase voltage potentially achieving CVR benefits.

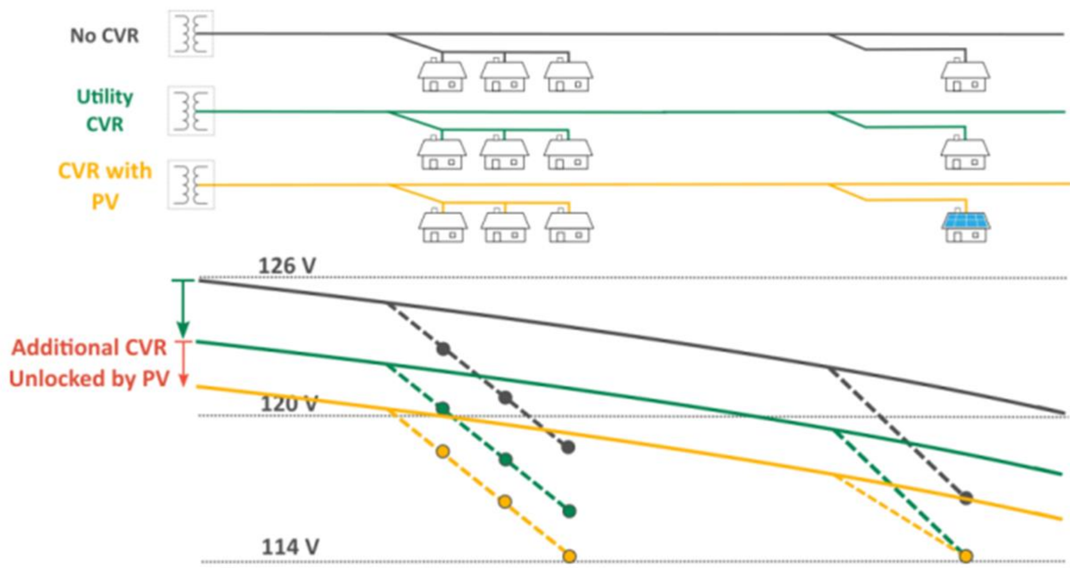
The IOUs do not agree that achieving CVR benefits from smart inverters is as simple as stated by Tesla and SEIA. Rather, upgrades to communication equipment, sensing, and control are required to optimize the smart inverters' capabilities to achieve CVR benefits. Specifically, strategic circuit configuration and communications / data systems are required for CVR benefits.

Fine-tuned controls are required to operate on the lowest possible edge of voltage limits, while serving all customers voltage within Rule 2 limits and realizing CVR benefits. If controls allow the voltage to increase too much, system-wide benefits are not realized. Without the specific conditions and requirements below, CVR through smart inverters will be inaccessible. IOUs and smart inverter providers need to collaborate to understand how to effectively implement CVR schemes into real world practice. Moreover, ongoing CVR studies at the IOUs will inform our understanding and quantification of CVR benefits.

Circuit Configuration Impacts CVR Benefits

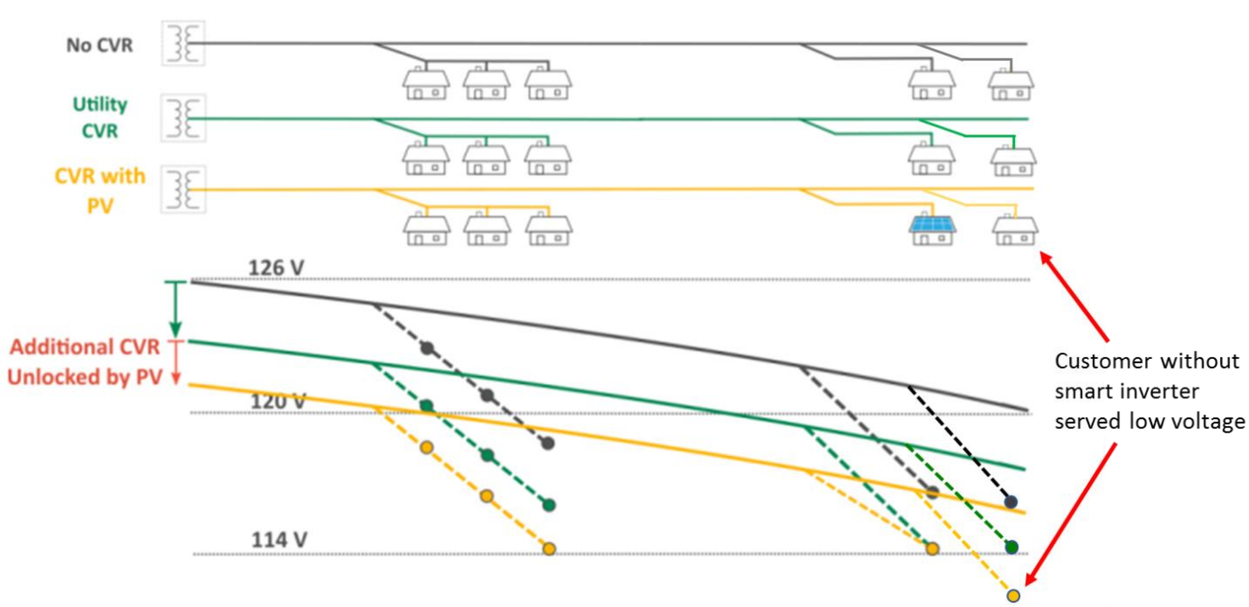
To potentially achieve CVR benefits, controlled VAR sources – both smart inverters and conventional sources – must be integrated into an overall CVR scheme, must be installed in strategic locations within the distribution feeders served from a single substation bus, and must be programmed based on locational CVR requirements. If the substation voltage is lowered without feeders equipped with controllable VAR resources at strategic locations on all the circuits integrated into a CVR scheme, there is an increased risk of serving high or low voltage to customers served from the same substation bus. This scenario could potentially result in customer equipment being damaged. The same concept holds true when attempting to lower voltage at the substation while only several customers on the circuit have the ability to increase voltage at their specific locations. The graph presented by SEIA/Tesla (Figure 1) depicts an idealized version of the potential impacts of lowering the substation voltage. Smart Inverters with the proper functions would have to be strategically installed at facilities on all the feeders from the substation and failing to do so would cause low voltage conditions. It is not as simple as installing one smart inverter to support the CVR smart inverter requirements as Figure 1 depicts.

Figure 1 – Image from SEIA Smart inverter Presentation



Specifically, this diagram (Figure 1) does not take account for customers downstream of the house with the ability to raise voltage at their location. In reality (Figure 2), if customers exist downstream of the same feeder, on unsupported bifurcated mainline, or on other feeders served out of the same substation without smart inverter functionality, these are at risk of being served high or low voltage.

Figure 2 – Customer without Smart Inverter Function Located at EOL Served Low Voltage



To implement CVR without the risk of serving low voltage to customers, all feeders connected to a substation need to be integrated in the CVR scheme and analyzed for voltage and loading impacts. Similarly, smart inverters would need to be strategically placed and programmed on all the feeders based on equipment and feeder characteristics to potentially achieve CVR benefits without detrimentally impacting customer voltage.

Communication and Data Systems are Necessary to Enable CVR

System-wide CVR benefits are unachievable in scenarios where smart inverters operate independently, without understanding the real time operations of the other smart inverters connected to the same substation bus. Centralized communication and control is essential to optimize the VAR production on the system to maintain required voltage levels. To calculate real time optimized smart inverter behavior, substation and feeder voltage data paired with smart inverter VAR production data must be transmitted to a centralized location. Distribution management systems would need the ability to send signals directly to smart inverters to inject or absorb VARs via Distributed Energy Resource Management System (DERMS) or Grid Management System (GMS). Due to the constant voltage changes throughout each day caused by the change in load, real time data acquisition and control is imperative. Moreover, the substation bus voltage and VAR sources must be dynamic. Additional communication and sensing equipment is required to achieve these functional capabilities. Without these capabilities smart inverters are blind to grid conditions that surround them unable to communicate with utility equipment and other neighboring smart inverters. These barriers would make it impossible to maintain the optimal voltage along a feeder to achieve CVR for customers.

Existing CVR Activities/Pilots Can Provide Insights

SCE is currently deploying a more “active” approach to CVR, called Distribution Volt/VAR Control (DVVC). The current deployment of DVVC is based off of a central control algorithm that was developed to control VAR producing equipment for applicable system configurations. Strategically placed capacitors on distribution feeders, combined with the centralized control algorithm and voltage sensing on distribution feeders and substations, enable DVVC to capture potential CVR benefits. To achieve CVR benefits, SCE has found that additional equipment must be deployed to enable the monitoring and control of all VAR sources connected to a single substation bus. This equipment is needed to optimize voltage levels throughout the distribution system. In addition, as part of SCE’s Integrated Grid Project (IGP), SCE is examining software that can potentially calculate optimal VAR dispatch to minimize circuit voltage.

To quantify the benefits of different control algorithm schemes and system configurations, technical studies are needed to quantify the benefits of different CVR implementations versus non volt VAR optimizations. The IOUs are currently performing pilot studies to test the capabilities required to achieve CVR benefits.

LNBA Incorporation

The LNBA should incorporate real achievable avoided costs that DERs can provide. Considering the sensing and communication equipment required to implement CVR with smart inverters, the IOUs should continue the ongoing research to understand how to achieve this before incorporating CVR energy savings as a benefit within the LNBA. Realizing CVR through smart inverters with existing capabilities is not technically feasible for deployment or regular existing operations. In addition to studying the feasibility of utilizing smart inverters to maintain voltage at optimized levels, the actual calculated benefits of CVR should be further explored. It is currently very difficult to calculate actual recorded energy savings from the reduction in voltage. Before incorporating a benefit value related to CVR within the LNBA, the actual benefit of CVR needs more research and refinement.

It is important to note that CVR at its core is an energy efficiency measure. While we can all agree the pursuit off energy efficiency in the electric system is always warranted it is important to realize that the value streams generated by energy efficiency programs are mostly realized by individual customers and not ratepayers as a whole. As specific customers operate more efficiently through optimized voltage levels in CVR they will realize the financial benefit of having to pay for less kWh consumed. There is no energy cost change relative to the rest of ratepayers because even though the utility will have to procure less energy, the customers benefitting from CVR will pay an equivalent amount less in energy costs. Furthermore, as the customers pay for less kWh their overall contribution to T&D costs will decrease while no decrease in utility T&D investment may be realized, thereby increasing T&D cost relative to other ratepayers resulting in additional cost shift. As smart inverters are capable of implementing CVR locally for customers and these benefits are only realized by those customers, one could argue that the value of efficiency gains through CVR is already accounted for and can be marketed to customers directly.

<u>TURN Comments on Tesla and SEIA Proposal for an Avoided Cost Value Related to Conservation Voltage Reduction from Solar Generation</u>

TURN appreciates the information provided by Tesla and SEIA regarding the potential for avoided costs related to conservation voltage reduction (CVR) from solar systems. TURN's guiding principle for development of the LNBA is that any avoided cost (benefit) included in the tool must be actually captured by all ratepayers (or at least have a reasonable probability of doing so). The inclusion of a CVR benefit for DERs does not meet this basic premise because the benefit described by Tesla/SEIA is entirely theoretical; any avoided cost value for CVR ascribed to solar will not actually be avoided and accrue to ratepayers. The only way the LNBA tool can provide additional value over the status quo is if it maintains analytical rigor to include benefits that actually accrue to ratepayers; this is not the case with CVR due to distributed solar generation at this time.

While the information provided by Tesla and SEIA may provide a sound *theoretical* basis for CVR benefits, the provision of these benefits requires active utility involvement to lower voltages and subsequent monitoring and data collection to determine energy and peak load reductions. This is not being accomplished by California utilities today. Further, the basis for avoided cost values (e.g. the "CVR factor") suggested by Tesla/SEIA are not related to demonstrations of CVR with solar, but rather for general voltage reductions not related to solar distributed generation.[21] TURN is not aware of any demonstrations that prove the CVR benefits of solar claimed by the Tesla/SEIA.

Avoided energy and capacity benefits due to voltage reductions are complex, depending entirely on the circuit, loads on that particular circuit, and the timing of when voltage is actually lowered *compared with what would have otherwise occurred in the absence of a particular CVR program*. TURN's analysis of PG&E's volt-var optimization program ("VVO," akin to CVR) pilot program (which did not involve solar but rather additional sensors and controls to lower voltage) demonstrated that the utility did not accurately forecast energy reductions, such that larger energy reductions were expected than what was actually measured for almost every circuit included in the pilot (all but one).[22] TURN also found that the pilot was not "able to demonstrate…[an] ability to reduce demand during peak system hours. The absence of demand reductions over this period call into question whether capacity costs can be avoided."[23]

Similar issues may be found with integrating solar into a utility CVR program, complicated by the fact that benefits depend entirely on where solar is located on a circuit. Nevertheless, TURN hopes solar developers can work with utilities (perhaps through an EPIC project) to implement and test CVR

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[21] The parties cite to an EPRI study that examines the benefits of lowering voltages. EPRI, Green Circuits, https://www.epri.com/#/pages/product/000000000001023518/.

[22] A.15-09-001, *Testimony of Eric Borden Addressing PG&E Electric Distribution and New Business Expenditures*, April 29, 2016, p. 12.

[23] *Ibid,* p. 13.

programs to demonstrate that lower voltages and related energy and peak demand reductions can be realized with distributed generation. Once such a program is developed and the concept and particular values demonstrated, an avoided cost value should be incorporated into the LNBA tool based on expected energy reductions from active utility involvement to lower voltages where solar DG is present.

Item 2.i: Automatically populate DER generation Profiles

Joint IOUs' Initial Proposal
LNBA Working Group

Summary of Recommendations

At the first long term refinement LNBA working group (WG) meeting held on July 7, 2017 the joint IOUs presented to the greater WG what was believed to be reasonable alterations to the LNBA spreadsheet tool to address long term refinement item 2.i in the Assigned Commissioner's Ruling dated June 7, 2017. This is a priority refinement in the ACR. The proposed alterations included the following:

1. Pre-Populate the LNBA Tool with publicly available DER shapes for solar, energy efficiency, and a generic baseload generation (flat shape).
    - IOUs recommend using public profile sources, specifically include NREL's PVWatts Calculator and E3's Energy Efficiency Calculator for solar and EE, respectively.
2. The solar and energy efficiency generation profiles would be obtained from public, vetted sources. This allows users to reproduce and obtain the DER shapes independently.
3. Location and PV system properties need to be determined to generate the appropriate solar profiles from PV watts.
4. A desired list of energy efficiency measures and technologies will need to be determined to obtain the appropriate EE profiles.
5. Other typical DER profiles can be included in the LNBA tool but should be publicly available.
    - It is expected that the WG stakeholders will submit all the DER profiles they wish to include in the new DER library.

Introduction and Background

After reviewing the IOUs demonstration B projects (Demo B), "the LNBA WG identified short-term improvements that improve the functionality of the LNBA tool and heat map. These improvements do not change the underlying LNBA analysis."[24]

The current version of the LNBA tool requires users to provide DER information such as the DER hourly profile. One of the improvements to the LNBA tool recommended by the WG and specified by the ACR is to include options to automatically populate DER generation profiles.[25] The sample profiles provided in the LNBA tool would be illustrative only.

[24] "Locational Net Benefits Analysis Working Group – Long Term Refinement Topics Scoping Document," More Than Smart, pg. 3.
[25] "Assigned Commissioner's Ruling Setting Scope and Schedule for Continued Long Term Refinement Discussions Pertaining to the Integration Capacity Analysis and Locational Net Benefits Analysis in Track One of the Distribution Resources Plan Proceeding," June 6, 2017, pg. 12.

Discussion

IOUs propose to create DER profile library that includes a reasonable amount of normalized profiles of common DER types. The profiles will be normalized to 1 kW which would facilitate the scaling of the selected DER profile by a user inputted size. The DER profile library would be included in the updated LNBA Tool.

By including a library of profiles with stakeholder input, the needs of a large majority of users should be met. Future additions can be made to the profile library to keep up with emerging technologies or DER use cases.

For the public sources of DER generation profiles, the IOUs recommended using National Renewable Energy Laboratory's (NREL) PVWatts Calculator[26] and Energy and Environmental Economics' (E3) 2013-2014 Energy Efficiency Calculator[27] to obtain typical solar and energy efficiency profiles, respectively.

Solar

The PVWatts Calculator allows users to input a location, select an appropriate weather data, and provide PV system properties (e.g., size, tilt, DC/AC ratio). Once the above information is provided through the online website, an hourly generation profile can be downloaded.

The next steps to develop the solar generation profile would be to determine the necessary inputs: location, associated weather data location, and PV system properties for the generic profile to be pre-populated in the tool. Once the inputs have been determined, solar profiles can be created and added to the LNBA tool.

Energy Efficiency (EE)

E3's Energy Efficiency Calculator provides hourly energy efficiency profiles for various measures. These hourly profiles represent the latest hourly profiles from the Database for Energy Efficient Resources (DEER)[28]. The DEER is a CPUC database that contains information on energy efficient technologies and measures relevant to California.

The next step would be to select representative energy efficiency measures or technologies and obtain the hourly profiles to be added to the LNBA tool.

Other

Stakeholders are welcome and encouraged to submit additional typical hourly DER profiles to be included in the tool. However, it is recommended that the source of the profiles be public, vetted and readily available.

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[26] NREL's PVWatts Calculator can be found at: http://pvwatts.nrel.gov/

[27] E3's 2013-2014 Energy Efficiency Calculator can be found at: https://www.ethree.com/public_proceedings/energy-efficiency-calculator/

[28] DEER information can be found at: http://deeresources.com/

Conclusion and Next Steps

- The Joint IOUs recommend using public profile sources include NREL's PVWatts Calculator and E3's Energy Efficiency Calculator for solar and EE, respectively.
- To obtain solar profile(s) from PVWatts, input assumptions must be determined. These inputs include location, associated weather locations, and PV system properties. The joint IOUs seek input from the solar parties in the working group for a typical solar installation.
- To obtain the energy efficiency profiles, a set of recommended energy efficiency measures and technologies will need to be selected. The Joint IOUs will select some energy efficiency measures and present that selection to the working group.
- Working group members are encouraged to submit additional sources to other typical DER profiles that can be included in the LNBA Tool. These sources should be publicly available.

Item 2.ii / Item D: Enabling modeling of a portfolio of DER projects at numerous nodes to respond to a single grid need

Joint IOUs' Initial Proposal
LNBA Working Group

Summary of Recommendations

The IOUs have proposed a set of modifications to the spreadsheet tool to enable multiple DER projects to meet a single need. The IOUs recommend implementation of these modifications.

Introduction and Background

The Current LNBA tool allows modeling of only a single DER profile. As noted in the MTS scoping document, "After review of the final Demo B projects, the WG was in consensus that the LNBA tool should be refined to support benefit analysis of a portfolio of projects at numerous nodes."

The ACR setting the scope of the long-term refinement topics includes the following: "Improve heat map and spreadsheet tool by: …; ii) enabling modeling of a portfolio of DER projects at numerous nodes to respond to a single grid need".

At the first long term refinement LNBA working group (WG) meeting held on 7/7/17 the joint IOUs presented to the WG alterations to the LNBA spreadsheet tool to address long term refinement items 2i and 2ii from the LNBA WG long term refinement report as identified in the Assigned Commissioner's Ruling dated 06/07/2017.

Discussion

The proposed alterations included the following:

1. In accordance with the 2.ii refinement, revise the tool to enable multiple DERs of different types and in different down-stream locations to be aggregated such that they can be modeled as solutions to a single need by adding several more columns to the "User input DER Profile Section" on the DER Dashboard tab to allow the user to input several additional and separate DERs profiles/locations.

   This will allow DER providers to create the DER portfolio that is appropriate for their project or customer needs.

2. Create user dropdowns above each one of these columns to allow the user to select a predefined 8760 hour DER profile from a new DER profile library to populate the column.

As noted above, with the creation of a library of profiles, the DER provider may not have to manually input a DER profile to perform analysis on their project.

3. Each column will also have a cell dedicated to scaling the profile. The scaling cell will simply be a numeric value which will be used to multiply the base profile by in order to scale up or down the resource.

   By normalizing the profile to 1kW and providing a scaling factor, the tool will allow for any size DER to be analyzed.

4. Have the new columns aggregate into the one existing DER profile column on the DER Dashboard tab to analyze overall financial impact of all DERs combined.

   By having the tool combine and calculate the DER profiles, the DER provider is relieved of the need to do their own analysis. This can enable multiple DER providers to combine DERs of multiple technologies and down-stream locations to respond to a distribution need, creating new and innovative solutions to provide distribution services.

Conclusion and Next Steps

The IOUs believe the proposed alterations to the tool meet the requirements set forth in ACR. The greater LNBA working group had an opportunity to comment on the IOU proposal in the July 7th meeting. There seemed to be consensus among the WG that the IOUs proposal would be appropriate and meet the requirements of the ACR. The IOUs therefore recommend the above recommendations be implemented into the tool.

Topic 2.iii-VAR Profiles: Improve spreadsheet tool by allowing hourly VAR profiles to be input

Joint IOUs' Initial Proposal
LNBA Working Group

Summary of Proposal

1. The Joint IOUs (SCE, SDG&E, and PG&E) propose to collapse item 2.iii (VAR profiles) under item B (location-specific smart inverter capabilities)
2. The IOUs propose additions to the LNBA tool to enable both users to input a DER VAR profile as well as a VAR requirements profile to validate that the DER VAR profile meets the requirements to defer a voltage project

Introduction and Background

1. Voltage support investments – generally capacitors or voltage regulators – are made on the distribution system where needed to maintain the voltage within Rule 2 requirements.
2. In order to defer a voltage project, a DER must be able to bring the voltage on the relevant distribution line section within Rule 2 requirements. This can be done by managing real power alone (e.g. using energy efficiency to help boost voltage) or using smart inverters to provide both real and reactive power support.

Discussion

3. The Joint IOUs (SCE, SDG&E, and PG&E) propose to collapse item 2.iii (VAR profiles) under item B (location-specific smart inverter capabilities).
   - 3.1. In general, a smart inverter is needed for a DER to provide reactive power; hence it makes sense to consider adding DERs' reactive power (VAR) capabilities to the LNBA tool as a subset of item B
   - 3.2. Additional smart inverter capabilities will be addressed after VAR profiles, since item 2.iii is a "priority item" while item B is not.
   - 3.3. When this proposal was discussed during the 7/15 and 8/15 WG meetings, WG participants expressed support for this suggestion; no WG member expressed opposition.

Proposal

1. **Modify the LNBA Tool to accept a DER VAR Profile**

1.1. This modification simply involves adding an hourly VAR profile along with the current hourly active power (kW) input. This is mocked up below.

DER Hourly Shape and Calculations

User Input for DER Hourly Shape

PST Hour Starting	Month	Hour	DER at meter (kW)	DER at meter (VAR)
1/1/15 12:00 AM	1	0	0.00	0.00
1/1/15 1:00 AM	1	1	0.00	0.00
1/1/15 2:00 AM	1	2	0.00	0.00
1/1/15 3:00 AM	1	3	0.00	0.00
1/1/15 4:00 AM	1	4	0.00	0.00
1/1/15 5:00 AM	1	5	0.00	0.00
1/1/15 6:00 AM	1	6	0.00	0.00
1/1/15 7:00 AM	1	7	0.00	0.00
1/1/15 8:00 AM	1	8	105.30	105.30
1/1/15 9:00 AM	1	9	720.21	720.21
1/1/15 10:00 AM	1	10	154.16	154.16
1/1/15 11:00 AM	1	11	293.76	293.76

Fig 1.

2. **Modify the LNBA Tool to accept a VAR Requirements Profile**
   2.1. As with the real power requirements for reducing load to mitigate a thermal constraint and defer a capacity upgrade, a VAR requirement profile is needed for deferring voltage projects.
   2.2. The tool must simply be modified to accept a VAR requirements profile and to validate that the DER VAR profile input meets or exceeds this requirement profile, again analogous to real power for capacity project deferrals. This modification is mocked up below.

Area	DPA 1									
Threshold	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
	Load (kW)									
Date & time										

Area	DPA 1									
Threshold	-	-	-	-	-	-	-	-	-	-
	VAR (kVAR)									
Date & time (Hour Beg)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
1/1/13 0:00	-	-	-	-	-	-	-	-	-	-
1/1/13 1:00	-	-	-	-	-	-	-	-	-	-
1/1/13 2:00	-	-	-	-	-	-	-	-	-	-
1/1/13 3:00	-	-	-	-	-	-	-	-	-	-
1/1/13 4:00	-	-	-	-	-	-	-	-	-	-
1/1/13 5:00	-	-	-	-	19	19	19	25	25	25
1/1/13 6:00	-	-	-	-	19	19	19	30	30	30
1/1/13 7:00	-	-	-	-	19	19	19	30	30	30

Fig 2.

Conclusion and Next Steps

1. The IOUs must develop a methodology for calculating the hourly VAR requirement profile.
   1.1. The IOUs don't currently have all the tools required to do this, though they're currently in development as part of the ICA work

1.2. At the same time, Rule 21 rules are currently in flux regarding reactive power requirements and power factor limits which would also influence the development of VAR profiles.
1.3. DERs will always have both a real and reactive power contribution, and both real and reactive power have an impact on voltage. Hence assumptions for DERs' power factor are needed, and these will be impacted by Rule 21 requirements currently being considered.

2. Subsequent discussions will address additional smart inverter capabilities related to other grid services (e.g. CVR and situational awareness).

Item 4.i: Additional Locational Granularity into Avoided Energy

Joint IOUs' Initial Proposal
LNBA Working Group

Note: In the June 7 ACR, Item 4 states: "Incorporate additional locational granularity into Energy, Capacity, and Line Losses." The IOUs have subdivided this item into three separate items covering energy, line losses, and capacity (respectively).

Summary of Recommendations

6. Replace the system-wide avoided energy forecast from the 2016 DERAC with DLAP price forecasts for each IOU.
    - Remove the system-wide avoided energy values currently obtained from Energy and Environmental Economics' (E3) 2016 Distributed Energy Resource Avoided Cost (DERAC) model. Add default load aggregation point (DLAP) forecast for the three IOUs. DLAP prices represent the cost that the IOUs incur when serving its customers' load.
7. Consistent with current system-wide avoided energy values, the any GHG avoided cost component would be removed from the DLAP forecast since the LNBA tool incorporates a GHG forecast as a separate avoided cost component.
8. The next step is to propose a methodology for forecasting the DLAP prices.

Introduction and Background

The current avoided energy cost utilizes a system-wide forecast obtained from the 2016 DERAC model. The system-wide forecast does not provide any value differentiation between locations. As part of the recommendations following the IOUs' DRP demonstration project B, the LNBA WG recommended to update the avoided energy cost with more location specific values as an improvement to the LNBA tool.[29] For the long term refinement of the LNBA, this task is one of the priority items to be accomplished.[30]

At the first long term refinement LNBA working group (WG) meeting held on July 7, 2017 the joint IOUs presented to the greater WG what was believed to be reasonable alterations to the LNBA spreadsheet tool to address long term refinement item 4 – locational avoided energy in the Assigned Commissioner's Ruling dated June 7, 2017.

Discussion

The DLAP price is a weighted average of all the locational marginal prices (LMPs) within the DLAP area. The DLAP area represents a geographic area within CAISO where demand bids "shall be submitted and

[29] "Locational Net Benefits Analysis Working Group – Long Term Refinement Topics Scoping Document," More Than Smart, pg. 4.

[30] "Assigned Commissioner's Ruling Setting Scope and Schedule for Continued Long Term Refinement Discussions Pertaining to the Integration Capacity Analysis and Locational Net Benefits Analysis in Track One of the Distribution Resources Plan Proceeding," June 6, 2017, pg. 12.

settled."[31] As noted by California Independent System Operator (CAISO), "load is bid in and settled at the DLAP LMP as opposed to the nodal LMP."[32] In other words, the DLAP price is what the IOUs pay to serve their customers. To follow the avoided cost methodology of the LNBA tool, the locational avoided energy forecast should be the DLAP forecasts associated with each IOU.

In order for the LNBA tool to be updated with the DLAP forecasts, a methodology must be developed to forecast the DLAP prices.

Conclusion and Next Steps

- Replace the system-wide avoided energy forecast from the 2016 DERAC with DLAP price forecasts for each IOU.
- DLAP prices represent the cost that the IOUs incur when serving their customers' load.
- The next step is to propose a methodology for forecasting the DLAP prices.
- The IOUs are currently evaluating the suitability of existing public DLAP forecasts.

[31] "Business Practice Manual for Definitions & Acronyms," CAISO, version 16, October 3, 2016, pg. 36.

[32] "Load Granularity Refinements, Pricing Study Results and Implementation Costs and Benefits Discussion," CAISO, January 14, 2015, pg. 11.

Topic 4-Capacity: Incorporate additional locational granularity into Capacity avoided cost values

Joint IOUs' Initial Proposal

LNBA Working Group

Summary of Proposal

3. The Joint IOUs (SDG&E, SCE and PG&E) propose to develop locational generation capacity avoided cost values at the CPUC's Local Resource Adequacy (Local RA) areas, which are based on CAISO's Local Capacity Requirement Area (LCR Area) level.
   3.1. Areas outside of a Local RA area would receive a system-level generation capacity avoided cost
4. The IOUs propose to use the recent, joint-IOU system-level generation capacity price forecast that was provided as a benchmark in the RPS proceeding.
5. Locational generation capacity avoided cost values will be determined using Local RA multipliers developed from the most recent data in the CPUC RA Report and applied to a system-level forecast that includes both short-run (i.e. RA-based) and long-run generation capacity value.
6. In each year, all generation capacity prices are capped at the net cost of new entry (CONE) for that year.
7. In the year that the system-level generation capacity price forecast reaches CONE, all other areas are also set at CONE

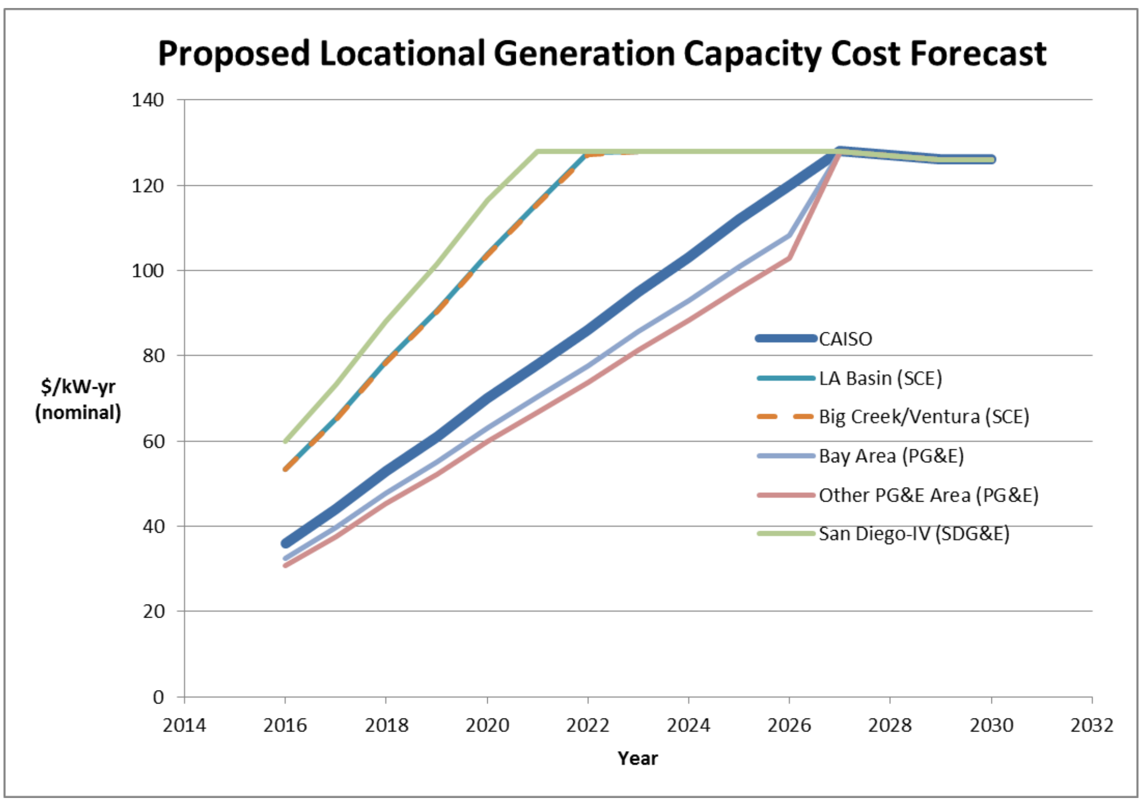


Fig. 1

Introduction and Background

4. Available Data on Locational Variation in Generation Capacity Value: The CPUC RA Report

4.1. The annual CPUC Resource Adequacy (RA) Report is the only public source of generation capacity price information in California. It provides aggregated RA contract price information at both the system-level and the Local RA area. Note: six small CAISO LCR areas in PG&E's territory are aggregated as one CPUC Local RA area, called "Other PG&E Area".

4.2. Since RA is not transacted in a centralized capacity market, this is the only public source of information with RA price information for system-level and Local RA.

4.3. Although this is the best available information, this report is based on voluntary responses to a CPUC data request and does not necessarily capture the entirety of RA contracts and transactions.

4.4. The CPUC's latest RA report is available here: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442453942

5. Resource Adequacy (RA) and Short-Run Generation Capacity Value

5.1. Load Serving Entities (LSEs) subject to CPUC jurisdiction must participate in the Resource Adequacy (RA) program.

5.2. RA refers to the program as well as the "capacity product" that LSEs must use to meet their System RA, Local RA and Flexible RA requirements. The capacity product can come from an LSE's generation portfolio and/or through contracts with generators to procure the RA-qualifying MW attributes of the generator.

5.3. Here we focus on System and Local RA, since Flexible RA does not vary within the CAISO.

5.4. In general, CAISO determines the RA requirements for reliable operation of the grid, and CPUC allocates those requirements to its jurisdictional LSEs. This requirement includes a 15% planning reserve margin.

5.5. Local RA is essentially no different from System RA, except that it is located in specific areas (i.e. load pockets) that have limited access to the transmission system.

5.5.1. Local RA is the only RA product that is "locational" – i.e. both the requirements, which are based on the August peak load in the LCR area, and the product are specific to a location on the system.

5.6. On a monthly basis, each LSE must demonstrate to CPUC that they have in their resource portfolio, either through ownership or contract, sufficient RA resources (i.e. operational generating capacity) to meet their RA requirement.

5.7. When DERs qualify as an RA resource, they can be compensated through a contract with an LSE for their RA attribute.

5.8. When DERs don't qualify as RA but have an impact on the LSE's RA requirement, those DERs can avoid or increase the LSE's RA compliance costs.

5.8.1. For example, if EE reduces the LSE's peak load by 5 MW, then one can calculate the associated RA procurement cost reduction.

5.8.2. Conversely, if EVs increase the LSE's peak load by 5 MW, one can calculate the associated RA procurement cost increase.

5.9. Regardless of whether DERs qualify as RA or impact an LSE's RA requirement, RA prices represent the short-run generation capacity avoided cost, since in the near-term, DERs simply increase or decrease an LSE's RA procurement.

6. Long-Run Generation Capacity Avoided Cost and Net Cost of New Entry (CONE)

6.1. In general, the near-term RA prices are low relative to the cost of new generation, because there is an excess of generators available to provide additional RA if needed.

6.2. In the long-run, however, generators may be retired and loads may grow such that there is no-longer an excess of generators. In this year, the "resource balance year" (RBY), LSEs will need to contract with a new generator in order to meet their RA obligation.

6.3. The net cost of new entry (CONE) is an estimate of how much generation capacity would cost from a new generator. It is an estimate of the levelized annual cost of building a new generator less the levelized annual energy and ancillary service revenue the plant would be expected to generate.

6.4. In the RBY and beyond, DERs are reducing the amount of new generating capacity that must be built; hence the CONE represents the long-run generation capacity avoided cost.

6.5. In any year, CONE represents the maximum generation capacity avoided cost, since it reflects the cost of increasing generating capacity by building a new generator.

6.6. CONE includes cost components, such as the cost of land for a new generator, which could vary by location; however, since CONE is based on a system-level shortage of resources, such components are evaluated locationally to calculate location-specific variants of the CONE.

Discussion

1. Level of Granularity for Generation Capacity

1.1. As described above, RA can be either System or Local, depending on whether a resource is located in a CPUC-designated Local RA area, informed by CAISO's LCR Areas.

1.2. The highest level of granularity for RA price variation is therefore at the Local RA level.

2. LNBA WG discussions

2.1. During the 7/15 LNBA WG meeting, the IOUs introduced the CPUC RA report and existing public generation capacity price forecasts, including the forecast currently in the Demo B LNBA tool.

2.2. Discussion centered on the need to reconcile the requirement for location-specific generation capacity avoided costs in LNBA with the fact that the only locational information available (i.e. the CPUC RA report) applies to the short-run generation capacity cost (i.e. RA prices) but not to the long-run generation capacity avoided cost (i.e. CONE). Stakeholders expressed openness to an IOU proposal which used RA price data to develop short-run locational generation capacity avoided costs.

2.3. During the 8/15 LNBA WG meeting, the IOUs presented the proposal described here and answered questions. This proposal incorporates feedback from that discussion.

3. Use of the Resource Balance Year in Light of IDER Decision D.16-06-007

3.1. Decision 16-06-007 in the IDER proceeding required the use of capacity benefits based on the long-run avoided capacity cost when doing cost-effectiveness analyses of demand-side management programs. Similarly, it prohibited the concept of resource balance year (a.k.a. year of need) in the Commission's DER avoided cost model.

3.2. LNBA is not currently used for the purpose of evaluating cost-effectiveness of DER programs and tariffs. Rather it is an indicator of locational value for DER benefits that could be calculated using Least-Cost/Best-Fit methodology in an IOU's procurement solicitation. As such, this proposal is not considered to be limited by D.16-06-007 regarding the use of resource balance year.

3.3. If this proposal is incorporated into the LNBA methodology and if a Commission decision directs the LNBA to be used for purposes of DER cost-effectiveness in IDER, the Commission would also have to modify D.16-06-007 and potentially require additional stakeholder review in the IDER proceeding.

Proposal

3. Calculate short-term LCA Multipliers

3.1. The IOUs propose to develop short-term RA price multipliers for each Local RA area by dividing the most recent[33] weighted average Local RA prices (see Table 8 in the CPUC RA Report) by the weighted average price for the CAISO system.

3.2. This yields the following locational factors for identified areas within the CAISO territory:

Area	LA Basin (SCE)	Big Creek/ Ventura (SCE)	Bay Area (PG&E)	Other PG&E Area (PG&E)	San Diego-IV (SDG&E)	System
2016-20 Wtd. Avg. Price x 12 ($/kW-yr)	43.44	43.32	26.4	25.08	48.72	29.28
LCA factors based on wtd. avg. LCA price WRT system price	1.48	1.48	0.90	0.86	1.66	1.00

Table 1

4. Apply Local RA Multipliers to Short-Run Generation Capacity Price Forecast to yield locational Generation Capacity Values

4.1. These locational factors, since they are based on RA prices, are applicable to short-run avoided generation capacity cost.

4.2. For this proposal, the IOUs propose using the Joint IOU RA Benchmark Price Forecast Proposal filed in the RPS Proceeding

4.2.1. When LSEs request offers in an RPS solicitation, they estimate the value of each resource to decide which to procure. This includes estimating the resource's RA value.

4.2.2. In 2016, the joint IOUs filed a public, informational RA price forecast to help RPS providers understand how RA is valued.

4.2.3. The joint IOUs developed this forecast using a version of E3's DERAC calculator used in the SGIP program with inputs developed using public information to mimic how the IOUs view the value of RA in procurement.

4.2.4. This forecast includes both short-run and long-run generation capacity prices.

4.2.5. This filing is available here: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M168/K107/168107777.PDF

4.3. These locational factors are thus multiplied by the system-level short-run (i.e. pre RBY) RA price forecast for each year provided by the joint IOUs in the RPS proceeding, with the result capped at CONE, since this would be the maximum avoidable cost in any year. Though some areas will reach CONE before the RBY, this does not necessarily mean that that area has a need for new capacity or has an area-specific RBY.

[33] The prices in this table are for "compliance years 2016 – 2020." Since LSEs procure RA in advance of the year that it's needed, the most recent transactions will include RA purchases for "delivery" in future years. These are all lumped together in the RA Report.

4.4. For the RBY and subsequent years, the CONE becomes the RA price forecast across all areas.
4.5. The result is provided here in Fig. 1.

Conclusion and Next Steps

3. The proposed approach uses the available public data on locational generation capacity value – the RA price report – to develop locational generation capacity avoided costs in a way that is consistent with the nature of that data as short-term RA price information.
4. The proposed method yields results that more accurately reflect the IOUs' actual avoided costs than the current DERAC values.
5. LNBA WG participants are invited to provide written comments on this proposal, including on concerns regarding consistency with D.16-06-007 for inclusion in the 8/31 LNBA WG status report.

Topic 4ii-Capacity: Incorporate additional locational granularity into Capacity avoided cost values

SEIA Proposal
LNBA Working Group

Summary of Proposal

SEIA proposes to develop locational generation capacity avoided cost values based on the loss-adjusted Cost of New Entry (CONE) in each IOU service territory. This would be consistent with D. 16-06-007 which established the CONE as the avoided generation capacity cost for DERs, without the use of a Resource Balance Year (RBY) to transition from short-run to long-run avoided capacity costs that accurately value distributed energy resources.

Introduction and Background

7. **Available Data on Locational Variation in Generation Capacity Value: The CPUC RA Report**
    7.1. The annual CPUC Resource Adequacy (RA) Report is the only public source of short-run generation capacity price information in California. It provides aggregated RA contract price information at both the system-level and the Local RA area.
    7.2. Since RA is not transacted in a centralized capacity market, this is the only public source of information with RA price information for system-level and Local RA.
    7.3. Although this is the best available information, this report is based on voluntary responses to a CPUC data request and does not necessarily capture the entirety of RA contracts and transactions.
    7.4. The CPUC's latest RA report is available here: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442453942
8. **Resource Adequacy (RA) and Short-Run Generation Capacity Value**
    8.1. Load Serving Entities (LSEs) subject to CPUC jurisdiction must participate in the Resource Adequacy (RA) program.
    8.2. RA refers to the program as well as the "capacity product" that LSEs must use to meet their System RA, Local RA and Flexible RA requirements. The capacity product can come from an LSE's generation portfolio and/or through contracts with generators to procure the RA-qualifying MW attributes of the generator.
    8.3. Here we focus on System and Local RA, since Flexible RA does not vary within the CAISO.
    8.4. In general, CAISO determines the RA requirements for reliable operation of the grid, and CPUC allocates those requirements to its jurisdictional LSEs. This requirement includes a 15% planning reserve margin.
    8.5. Local RA is essentially no different from System RA, except that it is located in specific areas (i.e. load pockets) that have limited access to the transmission system.
        8.5.1. Local RA is the only RA product that is "locational" – i.e. both the requirements, which are based on the August peak load in the LCR area, and the product are specific to a location on the system.

8.6. On a monthly basis, each LSE must demonstrate to CPUC that they have in their resource portfolio, either through ownership or contract, sufficient RA resources (i.e. operational generating capacity) to meet their RA requirement.

8.7. When DERs qualify as an RA resource, they can be compensated through a contract with an LSE for their RA attribute.

8.8. When DERs don't qualify as RA but have an impact on the LSE's RA requirement, those DERs can avoid or increase the LSE's RA compliance costs.

8.8.1. For example, if EE reduces the LSE's peak load by 5 MW, then one can calculate the associated RA procurement cost reduction.

8.8.2. Conversely, if EVs increase the LSE's peak load by 5 MW, one can calculate the associated RA procurement cost increase.

9. Long-Run Generation Capacity Avoided Cost and Net Cost of New Entry (CONE)

9.1. In general, the near-term RA prices are low relative to the cost of new generation, because there is an excess of generators available to provide additional RA if needed.

9.2. In the long-run, however, generators may be retired and loads may grow such that there is no-longer an excess of generators. In this year, the "resource balance year" (RBY), LSEs will need to contract with a new generator in order to meet their RA obligation. Before its elimination the RBY was a much debated concept and year and was based on when lumpy supply-side solutions would be needed to meet capacity needs. As. D16-06-007 finds, the RBY is no longer appropriate in a high-DER world.

9.3. The net cost of new entry (CONE) is an estimate of how much generation capacity would cost from a new generator. It is an estimate of the levelized annual cost of building a new generator less the levelized annual energy and ancillary service revenue the plant would be expected to generate. The value of CONE can differ by utility service territory, due to factors such as siting costs, the expected energy and ancillary service rents, and different environmental regulations.

9.4. In the RBY and beyond, DERs are reducing the amount of new generating capacity that must be built; hence the CONE represents the long-run generation capacity avoided cost.

9.5. In any year, CONE represents the maximum generation capacity avoided cost, since it reflects the cost of increasing generating capacity by building a new generator.

9.6. CONE includes cost components, such as the cost of land for a new generator, which could vary by location; however, since CONE is based on a system-level shortage of resources, such components are evaluated locationally to calculate location-specific variants of the CONE.

9.7. CONE also should be adjusted for losses, because 1 MW of capacity supplied by DERs behind the meter is equivalent to 1 + Loss % MW of generation-level capacity from a new utility-scale generator, as a result of the losses between the utility-scale generator and loads. These loss percentages will vary by location, and thus so will CONE.

Discussion

4. Level of Granularity for Generation Capacity

4.1. As described above, RA can be either System or Local, depending on whether a resource is located in a CPUC-designated Local RA area, informed by CAISO's LCR Areas.

4.2. The highest level of granularity for RA price variation is therefore at the Local RA level.

5. LNBA WG discussions

5.1. During the 7/15 LNBA WG meeting, the IOUs introduced the CPUC RA report and existing public generation capacity price forecasts, including the forecast currently in the Demo B LNBA tool.

5.2. Discussion centered on the need to reconcile the requirement for location-specific generation capacity avoided costs in LNBA with the fact that the only locational information available (i.e. the CPUC RA report) applies to the short-run generation capacity cost (i.e. RA prices) but not to the long-run generation capacity avoided cost (i.e. CONE). Stakeholders expressed openness to an IOU proposal which used RA price data to develop short-run locational generation capacity avoided costs.

5.3. During the 8/15 LNBA WG meeting, the IOUs presented a proposal to parties and answered questions. This document outlines SEIAs concurrence on some issues of fact but rejection of the proposed replacement of CONE with local RA and a local RBY, in light of the long-run value of DERs and the Commission's recent elimination of the Resource Balance Year in D.16-06-007.

6. **Use of the Resource Balance Year in Light of IDER Decision D.16-06-007**

6.1. Decision 16-06-007 in the IDER proceeding required the use of capacity benefits based on the long-run avoided capacity cost when doing cost-effectiveness analyses of demand-side management programs. Similarly, it prohibited the concept of resource balance year (a.k.a. year of need) in the Commission's DER avoided cost model.

6.2. The IOUs argue that the LNBA will not be used for the purpose of evaluating cost-effectiveness of DER programs and tariffs. A Proposed Decision in R.14-08-013 released August 25, 2017 reaffirms that a revised DERAC calculator is an intended use case of the LNBA.

6.3. If this proposal is incorporated into the LNBA methodology and if a Commission decision directs the LNBA to be used for purposes of DER cost-effectiveness in IDER, the Commission would also have to modify D.16-06-007 and potentially require additional stakeholder review in the IDER proceeding.

6.4. SEIA also observes that the IOU method uses location-specific short-run RA values, but a system-wide resource balance year. Local areas with high short-run RA values are presumably closer to the RBY in that local area than the system as a whole, and thus should increase more quickly than system-average capacity values. However, the IOU method does not use RBYs for local resources areas.

6.5. SEIA and its members supported D. 16-06-007's elimination of the resource balance year concept when determining the cost-effectiveness of DERs. SEIA agrees with D. 16-06-007's conclusion to eliminate the RBY because distributed energy resources are displacing new capacity rather than short-term capacity, and because the RBY concept fails to recognize the full value of small-increment, short-lead-time, high priority resources such as DERs.

Proposal

1. **Calculate the loss-adjusted CONE for each IOU service territory.** SEIA proposes to develop IOU-specific, loss-adjusted CONE values for each IOU service territory. Loss adjustments should be based on peak period line losses in each IOU service territory from the generation level to the load level. These IOU-specific CONE values would reflect locational differences due to (1) differences in peak period losses in each IOU service territory and (2) different CONE calculations given variations in CONE between service territories as a result of differences in siting costs, energy rents, environmental costs, or the base cost of the marginal source of capacity.

Conclusion and Next Steps

6. SEIA proposes to use loss-adjusted CONE values specific to each IOU service territory as the locational avoided cost of capacity for the LNBA.
7. The proposed method yields results that more accurately reflect the IOUs’ actual avoided costs than the current DERAC values which do not use IOU-specific CONE values.

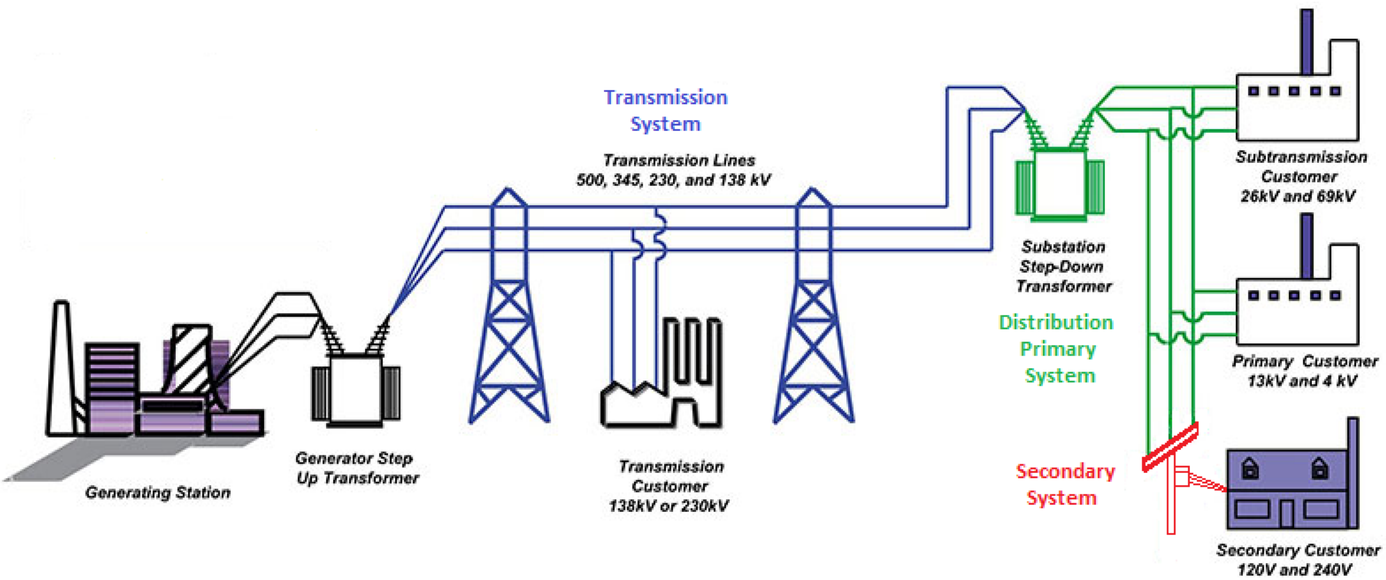
Item 4: Locational Based Line Loss Calculations

Joint IOUs' Initial Proposal

LNBA Working Group

Summary of Recommendations

- The LNBA working group (WG) collectively recommends that the existing system loss factor in the LNBA tool be split into several loss factors separately accounting for losses any DER may alter on a local transmission area, sub transmission, distribution primary, and distribution secondary systems they are interconnected and downstream of. The diagram below illustrates these separate systems.



- The LNBA WG recommends that the transmission loss factor remain the same for all DERs in each respective IOU's service territory as transmission losses will not be significantly impacted by deploying DER in one location vs another.
- SCE will perform a study on their own behalf to evaluate if their sub-transmission losses vary significantly by location. (SCE specific)
- The IOUS will expend the most effort evaluating distribution primary losses in a more detailed circuit modeling exercise for some subset of each IOUs distribution circuits. The evaluation will help determine the effect of DER location on distribution circuit losses and will help guide how loss factors should be included in the LNBA and whether the IOUs should pursue a more elaborate/labor intensive methodology of calculating location specific loss factors for each circuit/section
- The IOUs will also perform an evaluation of secondary system losses
- Future analysis may evaluate losses incurred by backfeeding secondary networks and distribution transformers.

- IOUs will develop high level cost estimates/timeframes of implementing various line loss calculation methodologies

Introduction and Background

As part of Demonstration Project B (Demo B), the IOUs coordinated with E3 to develop the LNBA tool which includes IOU system wide specific loss factors. The loss factors were used to estimate the benefit that DERs provide by avoiding line losses. For example, if a customer needs 0.9 MWh of energy, a generator would need to provide 1.0 MWh of energy to account for 10% line losses to deliver that energy. Locating DERs near the customer to provide the energy would avoid the both the energy needed by the customer as well as the energy needed to account for the line losses.

As part of the assigned commissioner ruling on long term refinements to ICA and LNBA, the Commission requests to "incorporate additional locational granularity into…line losses." The working group has suggested, as a first step, assess the variability of the line losses.

Discussion

- For a typical Electric system with large scale transmission interconnected generation feeding customers far away from its generating sources average losses are typically around 10%
- The existing LNBA tools currently calculates a DERs ability to reduce losses by either reducing load or delivering generation closer to load by multiplying the DER output by 1+system average loss factor. (if the average system losses was 10% this number would be 1.1) In addition to this the LNBA tool also evaluates the DER as providing 1.1 * its output for capacity reduction which help smaller DERs meet larger load reduction requirements in the interest of deferring a project
- Calculating losses is computationally intense because losses increase or decrease based on many different variables. Loading, load frequency, load allocation on a circuit, circuit conductor length, voltage level, conductor type, generation location, capacitor location, power factor, system operations, and other factors all play a role in determining losses.
- Because so many components go into line loss calculations one requires a large amount of data as well as data accuracy to accurately calculate line loss reductions caused by a DER. Even with precise data and calculations the distribution systems are dynamic in that loads, generation, and circuits configurations are subject to change all the time so the value of reduced losses is an estimate only.
- The LNBA WG acknowledges there may not be evidence that the variation in loss reduction is significant enough to warrant intense IOU effort to develop the tools necessary to estimate line loss reduction more accurately, however the IOUs will conduct a preliminary evaluation of line loss variation in order for the greater WG to determine if it is actually worth pursuing and if so to what degree of accuracy. The results of this preliminary study will be presented at the November WG meeting.
    - Each IOU will perform an analysis that follows the following steps:
        - Select a set of feeders for analysis seeking to capture a cross section on characteristics most likely to influence losses (e.g. length, voltage, loading)
        - Evaluate variability of losses among the selected feeders
        - Evaluate variability of losses within the selected feeders (i.e. different locations on each feeder)

        - Evaluate LNBA results sensitivity to losses
        - Recommend locational loss factor approach for LNBA tool (e.g. level of granularity, method for developing loss factors) that balances complexity with need to capture loss factor variability as a driver of LNBA results
- The preliminary study will serve to allow the allocation of resources to studying issues that have a more quantifiable impact to the LNBA than line losses in the interim.

Conclusion and Next Steps

- Perform the Preliminary study on distribution primary line losses, secondary losses, and export losses and share results with working group at meeting in November.

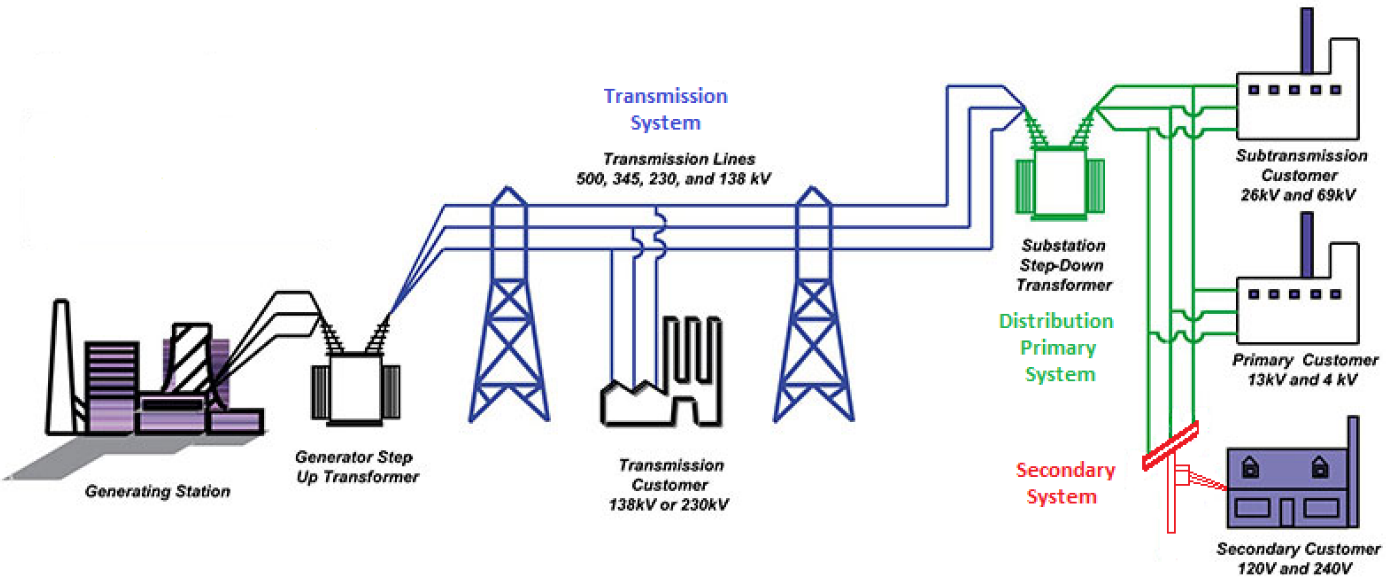
Item 4: Locational Based Line Loss Calculations

Joint IOUs' Initial Proposal

Clean Coalition Edits

Summary of Recommendations

- The LNBA working group (WG) collectively recommends that the existing system loss factor in the LNBA tool be split into several loss factors separately accounting for losses any DER may alter on a local transmission area, sub transmission, distribution primary, and distribution secondary systems they are interconnected and downstream of. The diagram below illustrates these separate systems.



- The LNBA WG recommends that the transmission loss factor remain the same for all DERs in each respective transmission area identified by CAISO as transmission losses will not be significantly impacted by deploying DER in one location vs another within these areas.[34]
- SCE will perform a study on their own behalf to evaluate if their sub-transmission losses vary significantly by location. (SCE specific)
- The IOUS will expend the most effort evaluating distribution primary losses in a more detailed circuit modeling exercise for some subset of each IOUs distribution circuits. The evaluation will help determine the effect of DER location on distribution circuit losses and will help guide how loss factors should be included in the LNBA and whether the IOUs should pursue a more elaborate/labor intensive methodology of calculating location specific loss factors for each circuit/section

[34] See CAISO, 2012 LOCAL CAPACITY TECHNICAL ANALYSIS FINAL REPORT AND STUDY RESULTS, April 29, 2011; CAISO, 2013 LOCAL CAPACITY TECHNICAL ANALYSIS ADDENDUM TO THE FINAL REPORT AND STUDY RESULTS: Absence of San Onofre Nuclear Generating Station (SONGS), August 20, 2012

- The IOUs will also perform an evaluation of secondary system losses
- Future analysis may evaluate losses incurred by backfeeding secondary networks and distribution transformers.
- IOUs will develop high level cost estimates/timeframes of implementing various line loss calculation methodologies

Introduction and Background

As part of Demonstration Project B (Demo B), the IOUs coordinated with E3 to develop the LNBA tool which includes IOU system wide specific loss factors. The loss factors were used to estimate the benefit that DERs provide by avoiding line losses. For example, if a customer needs 0.9 MWh of energy, a generator would need to provide 1.0 MWh of energy to account for 10% line losses to deliver that energy. Locating DERs near the customer to provide the energy would avoid the both the energy needed by the customer as well as the energy needed to account for the line losses.

As part of the assigned commissioner ruling on long term refinements to ICA and LNBA, the Commission requests to "incorporate additional locational granularity into…line losses." The working group has suggested, as a first step, assess the variability of the line losses.

Discussion

- For a typical Electric system with large scale transmission interconnected generation feeding customers far away from its generating sources average losses are typically around 10%
- The existing LNBA tools currently calculates a DERs ability to reduce losses by either reducing load or delivering generation closer to load by multiplying the DER output by 1+system average loss factor. (if the average system losses was 10% this number would be 1.1) In addition to this the LNBA tool also evaluates the DER as providing 1.1 * its output for capacity reduction which help smaller DERs meet larger load reduction requirements in the interest of deferring a project
- Calculating losses is computationally intense because losses increase or decrease based on many different variables. Loading, load frequency, load allocation on a circuit, circuit conductor length, voltage level, conductor type, generation location, capacitor location, power factor, system operations, and other factors all play a role in determining losses.
- Because so many components go into line loss calculations one requires a large amount of data as well as data accuracy to accurately calculate line loss reductions caused by a DER. Even with precise data and calculations the distribution systems are dynamic in that loads, generation, and circuits configurations are subject to change all the time so the value of reduced losses is an estimate only.
- The LNBA WG acknowledges there may not be evidence that the variation in loss reduction is significant enough to warrant intense IOU effort to develop the tools necessary to estimate line loss reduction more accurately, however the IOUs will conduct a preliminary evaluation of line loss variation in order for the greater WG to determine if it is actually worth pursuing and if so to what degree of accuracy. The results of this preliminary study will be presented at the November WG meeting.
    - Each IOU will perform an analysis that follows the following steps:
        - Select a set of feeders for analysis seeking to capture a cross section on characteristics most likely to influence losses (e.g. length, voltage, loading)
        - Evaluate variability of losses among the selected feeders

    - Evaluate variability of losses within the selected feeders (i.e. different locations on each feeder)
    - Evaluate LNBA results sensitivity to losses
    - Recommend locational loss factor approach for LNBA tool (e.g. level of granularity, method for developing loss factors) that balances complexity with need to capture loss factor variability as a driver of LNBA results
- The preliminary study will serve to allow the allocation of resources to studying issues that have a more quantifiable impact to the LNBA than line losses in the interim.

Conclusion and Next Steps

- Perform the Preliminary study on distribution primary line losses, secondary losses, and export losses and share results with working group at meeting in November.

Addendum

CAISO Transmission Areas and Peak Period Losses

Peak Load Transmission Losses - CAISO 2012

Area	Busload (MW)	Losses (MW)	Pumps (MW)	Total	Losses	Source:
LA Basin	19,300	133	27	19,460	0.7%	(1)
San Diego/Imperial Valley	4990	134		5,124	2.6%	(1)
Humboldt	200	10		210	4.8%	(2)
North Coast/North Bay Area	1386	34		1,420	2.4%	(2)
Sierra	1713	103		1,816	***5.7%***	(2)
Stockton	1067	19		1,086	1.7%	(2)
Greater Bay Area	9493	197	264	9,954	2.0%	(2)
Greater Fresno Area	3014	105		3,119	3.4%	(2)
Kern Area	1099	11		1,110	1.0%	(2)
Big Creek/Ventura	4260	78	355	4,693	1.7%	(2)
System Average					**1.8%**	
Renewables Areas					**2.7%**	

(1) - CAISO, 2013 LOCAL CAPACITY TECHNICAL ANALYSIS ADDENDUM TO THE FINAL REPORT AND STUDY RESULTS: Absence of San Onofre Nuclear Generating Station (SONGS), August 20, 2012
(2) - CAISO, 2012 LOCAL CAPACITY TECHNICAL ANALYSIS FINAL REPORT AND STUDY RESULTS, April 29, 2011