Integrated Capacity Analysis Working Group

August 15, 2017

In-person meeting

drpwg.org

MORE THAN SMART

Agenda

Time	Topic
9:00 – 9:30	A. Introduction, agenda, July recap, review of August 31st status report
9:30 – 10:30	B. Planning use case
10:30 – 10:45	C. Break
10:45 – 11:45	D. Smart inverter functionality 10:45 – 11:15: CALSEIA 11:15 – 11:45: Joint IOUs
11:45 – 11:20	E. Wrap up and next steps
12:00 – 1:00	Lunch

MORE THAN SMART

ICA Working Group

Group	Items: Explanations/Clarifications	Source (ACR/WG report)	Meeting date
I	Item 1: Further define ICA planning use case and methodologies	WG report	8/15
	Item 2: Develop standard PV generation profile for use in online maps – *near-term relevance to interconnection use case and online map display of ICA results*	WG report	7/7
	Item 5: Develop methods and tools to model smart inverter functionality in ICA calculations	WG Report	8/15
	Item 8: Perform comparative assessment of IOUs' implementation of ICA methodology on representative California reference circuits	WG Report	7/7
	Item A: Expansion of the ICA to single phase feeders – *requires creation of network models for single phase feeders*	ACR	7/7

MORE THAN SMART

ICA Working Group

The Interim Status Report on Group I topics is due **August 31.**

The ACR specifies that the "Status Reports shall briefly summarize the progress on each of the issues discussed to date and are not to be considered final proposals. Each scope issue should be covered within a maximum of one page."

The status report will include:

- Short description and summary of discussion for each Group I topic
- Written proposals, including edits from WG members
- Presentation slides, meeting notes, and other meeting materials

The status reports are meant to be informal and will be circulated to the DRP Proceeding service list, but not formally filed with the CPUC. MTS will lead drafting and compilation, and will circulate the final on August 31.

ICA Working Group

Upcoming schedule for written proposals:

8/15: ICA Meeting and Presentations
8/22: First draft written proposals due
8/29: Edits by WG members due
8/31: Status report due

Written proposals from the 7/7 meeting are online:
http://drpwg.org/sample-page/drp/

MORE THAN SMART

Agenda Item B: Planning Use Case

MTS Scoping document:

Objective: The ICA WG will determine how the ICA may inform and identify DER growth constraints and opportunities in the planning process, in which applications and how ICA may be used, and what methodology (streamlined or iterative), levels of granularity and frequency of updates, may best serve the planning use case.

Background: see scoping document for additional background study questions.

Scoping questions: the ICA WG should work to determine:

- What are the uses of ICA in planning as identified by other Tracks of DRP, other related proceedings (e.g., IDER) and other Commission guidance?
- From this pre-identified list of discussion questions, are there any to be added or subtracted?
- From these known uses, what methodological needs are required to meet these use cases? Would a streamlined, iterative, or blended approach be most sufficient to serve this use case?

Integration Capacity Analysis (ICA) – Working Group

IOU Slides – Planning Use Case (Topic #1)

August 15, 2017

Scope of the Planning Use Case

- What is it used for?
  - The utilization of ICA in the planning use-case is intended to assist with other planning and analysis techniques used by engineers
  - Helps find areas that may need proactive actions or investments to accommodate growth of retail DG

- What does it calculate?
  - Utilization of ICA in the planning use-case helps determine violations caused by the forecast
  - Timing and category components in ICA might help figure out what types of violations need to be addressed but not necessarily how to fix them
- What does not it calculate?
  - Utilization of ICA in the planning use-case does not determine the final solution needed to fix the violations identified
  - The utilization of ICA in the planning use-case must be coordinated with the overall system planning assessment to determine the final DER system upgrades needs
- Scope
  - Should align with normal planning cycle and be performed once a year
  - 1-5 year analysis including load growth and DER growth

Large Single Interconnection versus Small Dispersed Interconnection

- Planning requires us to evaluate the aggregate impact of many new DER versus a single DER at a specific location
- ICA so far has had a “interconnection” focus which evaluates DG impacts at single interconnection location(node) based on existing conditions
- The planning use case of ICA needs similar thinking to load planning where general overall growth is considered versus one location at a time
  - Not as easy given that every customer doesn’t have DG so applying growth factors is not as appropriate
- Ways to consider this
  - **Stochastic Placement:** Stochastically placing forecasted DG across circuit and then performing power flows to identify the violations created by the forecasted DER.
  - **EPRI DRIVE**: Applying Weibull distribution algorithms to equations to account for dispersion

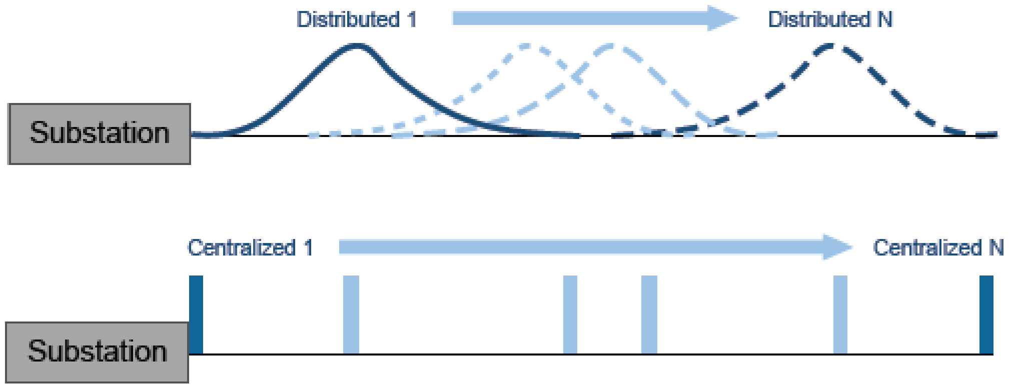
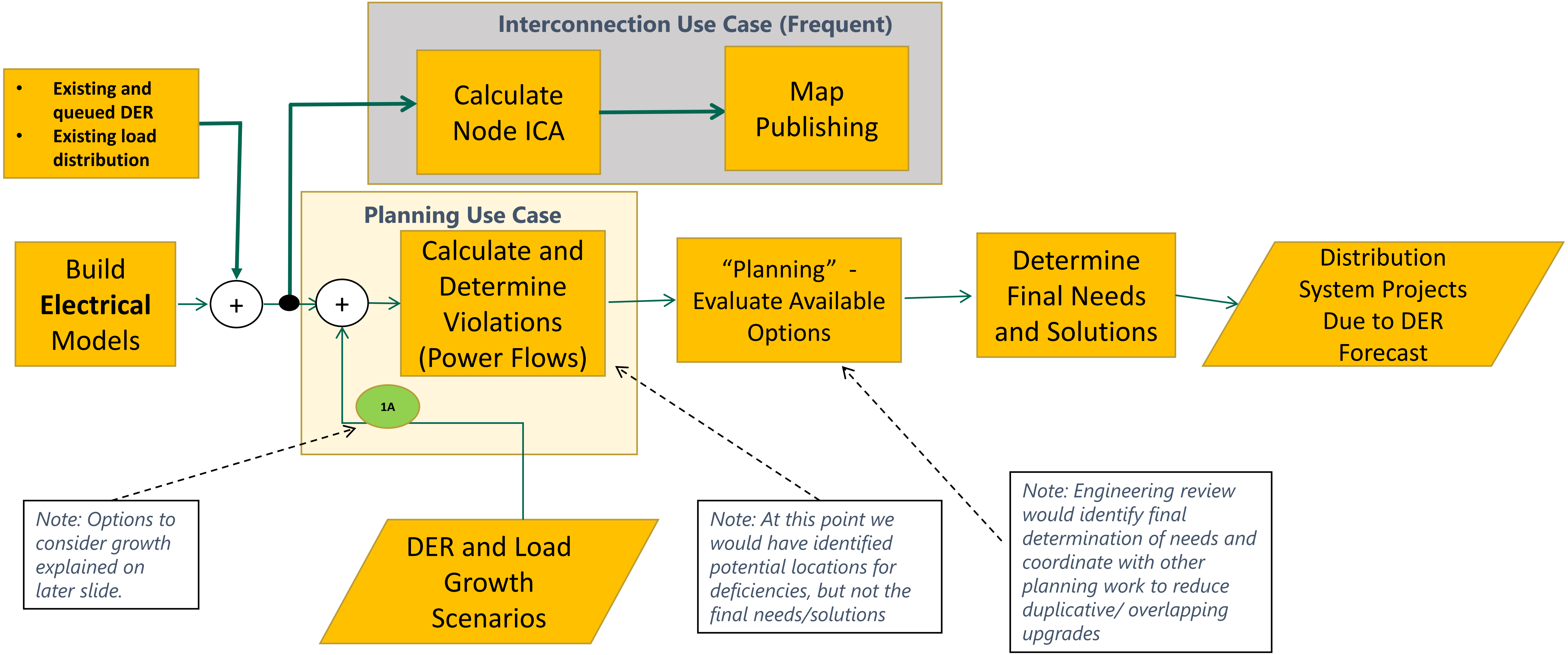


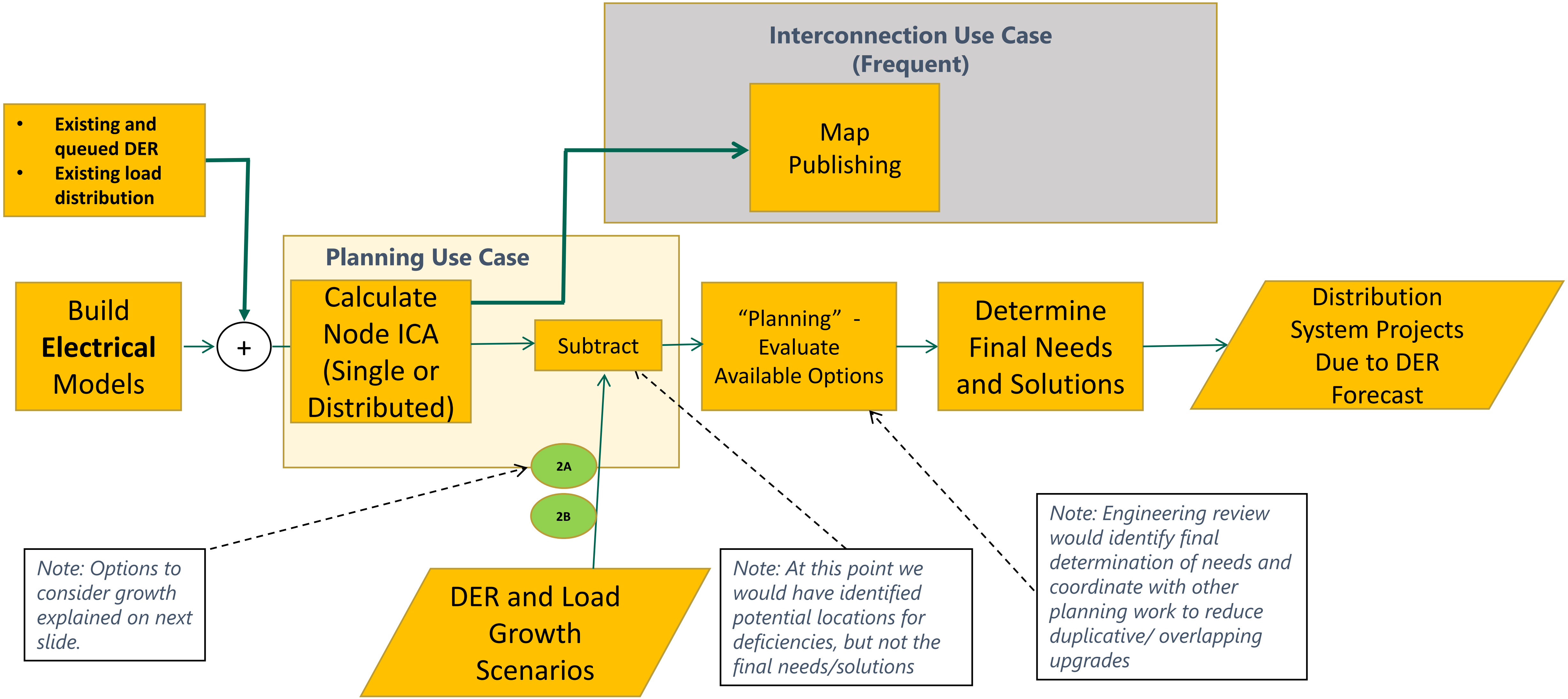
Figure 6 – Subset of DER Scenarios Analyzed in the Streamlined Analysis

Source: EPRI, INTEGRATION OF HOSTING CAPACITY ANALYSIS INTO DISTRIBUTION PLANNING TOOLS

Using ICA to determine Grid Needs for DER Growth

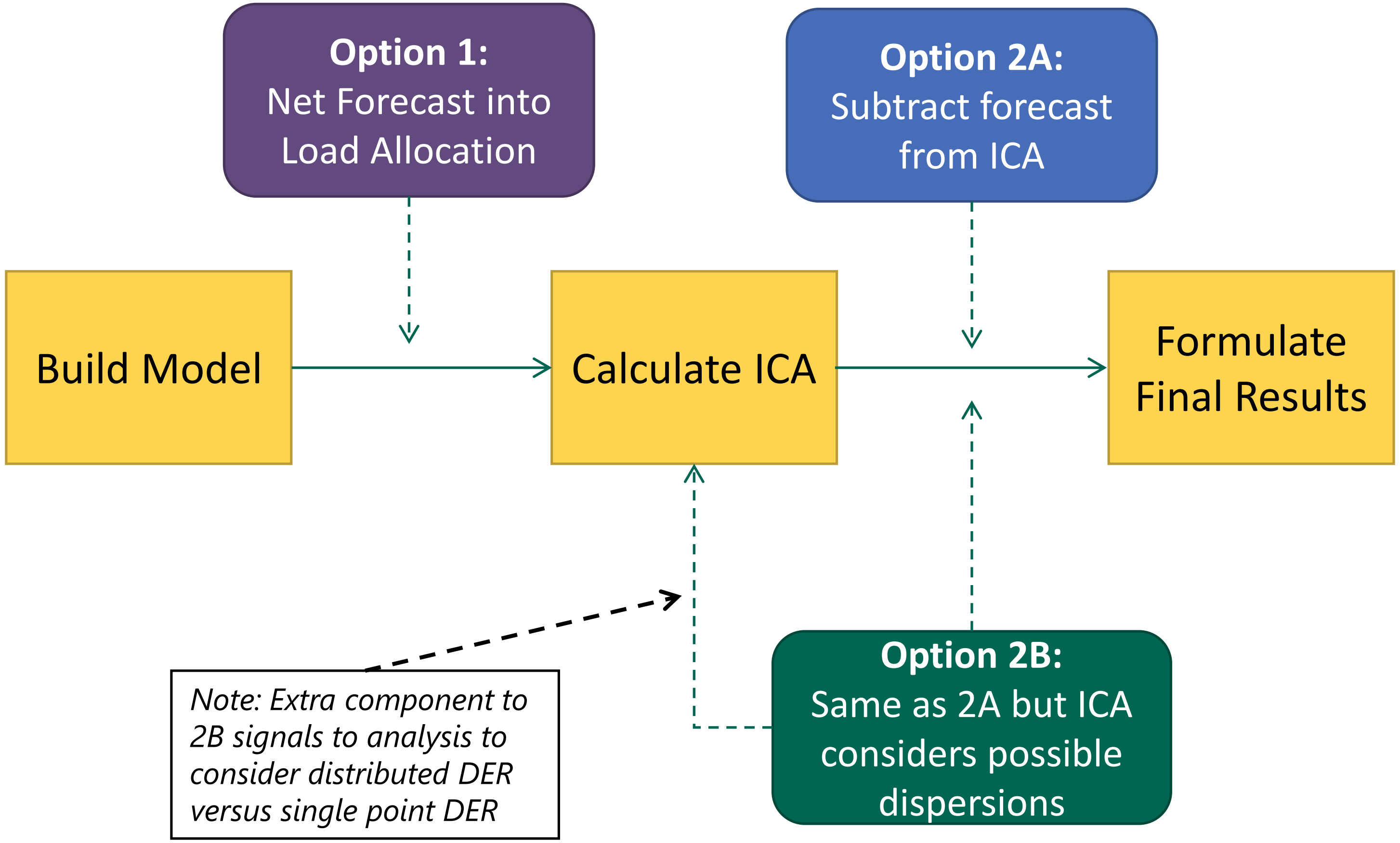


Using ICA to determine Grid Needs for DER Growth



How to Consider DER Growth in ICA

NOTE: DER Growth would be by feeder and thus makes specific line section ICA difficult to consider



1. Net Forecast into Load Allocation
   - DER growth netted into the load allocation before ICA is calculated
   - Attempts to more directly account for growth, but only accounts for a peanut butter distribution of DER

2A. Compare Growth to ICA
   - Option A utilizes current output of ICA evaluating single point ICA
   - The easiest to perform, but results don't really have any consideration of dispersion of DER on circuit

2B. Compare Growth to modified ICA
   - utilizes an ICA output that has considered the distribution of DER in the analysis
   - Would require adjustments to ICA for considering small dispersed DER versus large single point DER

Agenda Item D: Smart Inverter Functionality

MTS Scoping document: Develop methods and tools to model smart inverter functionality in ICA calculations

Objective: The WG should determine which additional studies are needed, and then use results to develop a methodology to include smart inverters within ICA.

Background: Within Demo A, the IOUs did not recommend methods for evaluating hosting capacity with smart inverter functionality, but tested smart Volt-var function within Demo A on a limited basis on one distribution feeder, to determine how smart inverters may be able to increase hosting capacity. Resulting studies revealed that smart inverters may be able to support higher levels of hosting capacity in certain system conditions.

The ICA WG acknowledges that additional studies are needed to develop an appropriate methodology for smart inverters, and that the use of engineering resources for this purpose will need to be prioritized alongside additional ICA study requirements for long-term refinement.

Scoping questions: Within long-term refinement, the ICA WG will discuss prioritization of studies, and work to develop an appropriate methodology for including smart inverter functionality within ICA.

Integration Capacity Analysis (ICA) – Working Group

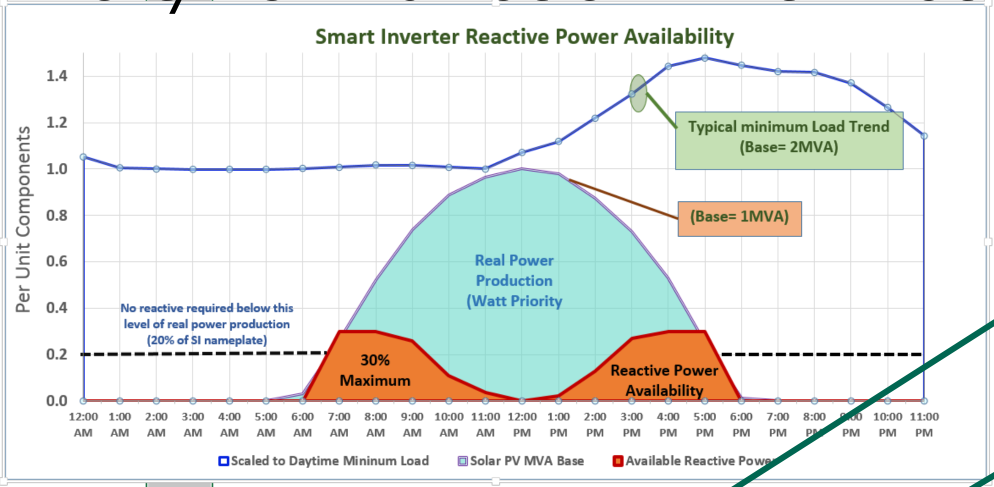
IOU Slides

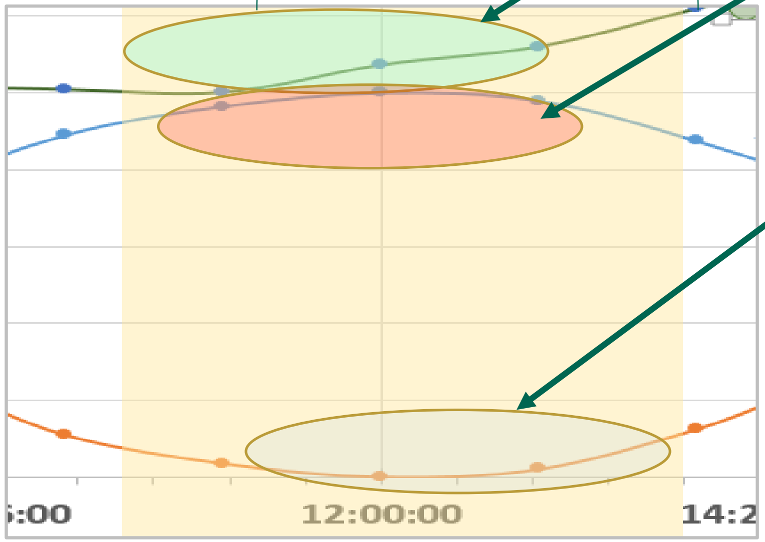
August 15, 2017

Smart Inverter Functions Capable To Support Higher ICA values

Function	Phase	Timing	Supports Higher ICA Values	Supports Higher Connected KW(KVA) Values	Comment	Limintations	Expanded Discussion
Anti-Islanding	I	Q4-2017	NO	NO	Safety Functions Requirement		
Low/High Voltage Ride-Through	I	Q4-2017	NO	NO	System Contribution		
Low/High Frequency Ride-Through	I	Q4-2017	NO	NO	System Contribution		
Dynamic Volt-Var Operations (Watt priority)	I	Q4-2017	Partially	Partially	Produces all real (KW) first and only reactive power if inverter has capacity remaining	Watt Priority Reduces Ability To Support Voltage Control	Yes
Dynamic Volt-Var Operations (Reactive priority)	Extended Phase I	Q4-2018 - Q4 2019	Yes	Yes	Rule 21 does not require oversize. Reduction on real power when reactive power absorved	Pending IEEE 1547.1 or CA stakeholders suport to activity earlier in CA	Yes
Ramp Rates Controls	I	Q4-2017	No	No	System Contribution		
Fix Power Factor	I	Q4-2017	Yes	Yes	Rule 21 does not require oversize. Reduction on real power when reactive power absorved	Deactivated, may connflict with voltage control	Yes
Reconnect via soft start	I	Q4-2017	NO	NO	System Contribution		
Communciation Capability	II	Q4-2018	NO	NO	Not intended to mitigate the violations which limit ICA	Capability Only - Not a requirement to apply	
Frequency Watt	III	Q4-2018	No	NO	System Contribution	Same as Volt/Watt	
Voltage/Watt	III	Q4-2018	NO	Yes	Will Reduce Real Power Production	Likely not available unitl Q3-2018. 12 months after approval of Phase III AL.	Yes
Monitor Key Data	III	Q4-2018	No	NO	Information	Capability Only - Not a requirement to apply	
DER Cease-to Energy/Return to service	III	Q4-2019	NO	NO	Control	Pendinng IEEE 1545.1 Standard Development- Capability Only	
Limit Maximum Active Power Mode	III	Q4-2019	NO	NO	Not intended to mitigate the violations which limit ICA	Pendinng IEEE 1545.1 Standard Development- Capability Only	
Scheduling Power Values and Modes	III	Q4-2018	NO	NO	Scheculing Capabilities	Capability to Schedule Only	

Volt/Var Function With Active (Watt) Power Priority





During minimum load periods at time concurrent with high levels of % PV real power output is when PV will tend to push the system voltage higher thus limiting ICA due to the steady state voltage ICA limit

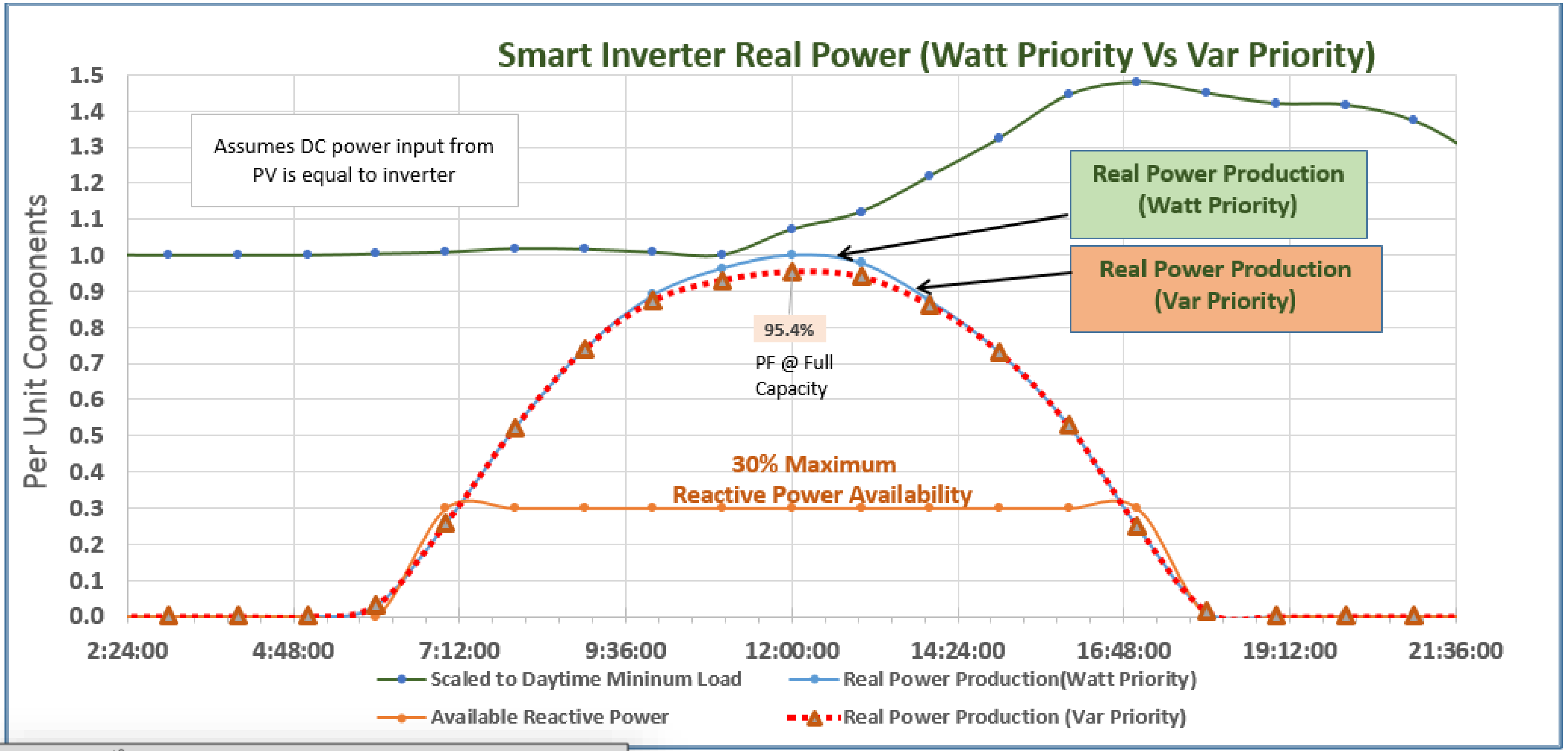
Depending on how the PV Generating Facility is designed (DC Power-Inverter Nameplate), inverters can be at full capacity producing real power

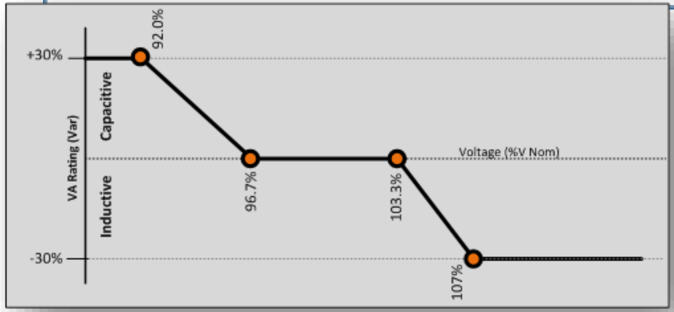
Depending on how the PV Generating Facility is designed (DC Power-Inverter Nameplate), inverters may not have any remaining capacity to absorb reactive power to help reduce the high voltage produced by the injection of real power into the system

IOU Recommendation

Because of this significant limitation, the IOUs conclude that the volt/var function with **Active Power Priority** cannot be used to increase ICA at each node. IOUs recommend waiting for the “Reactive Power” priority update to include Volt/Var with Reactive Power Priority in ICA calculations

Volt/Var Function With Reactive (Var) Power Priority



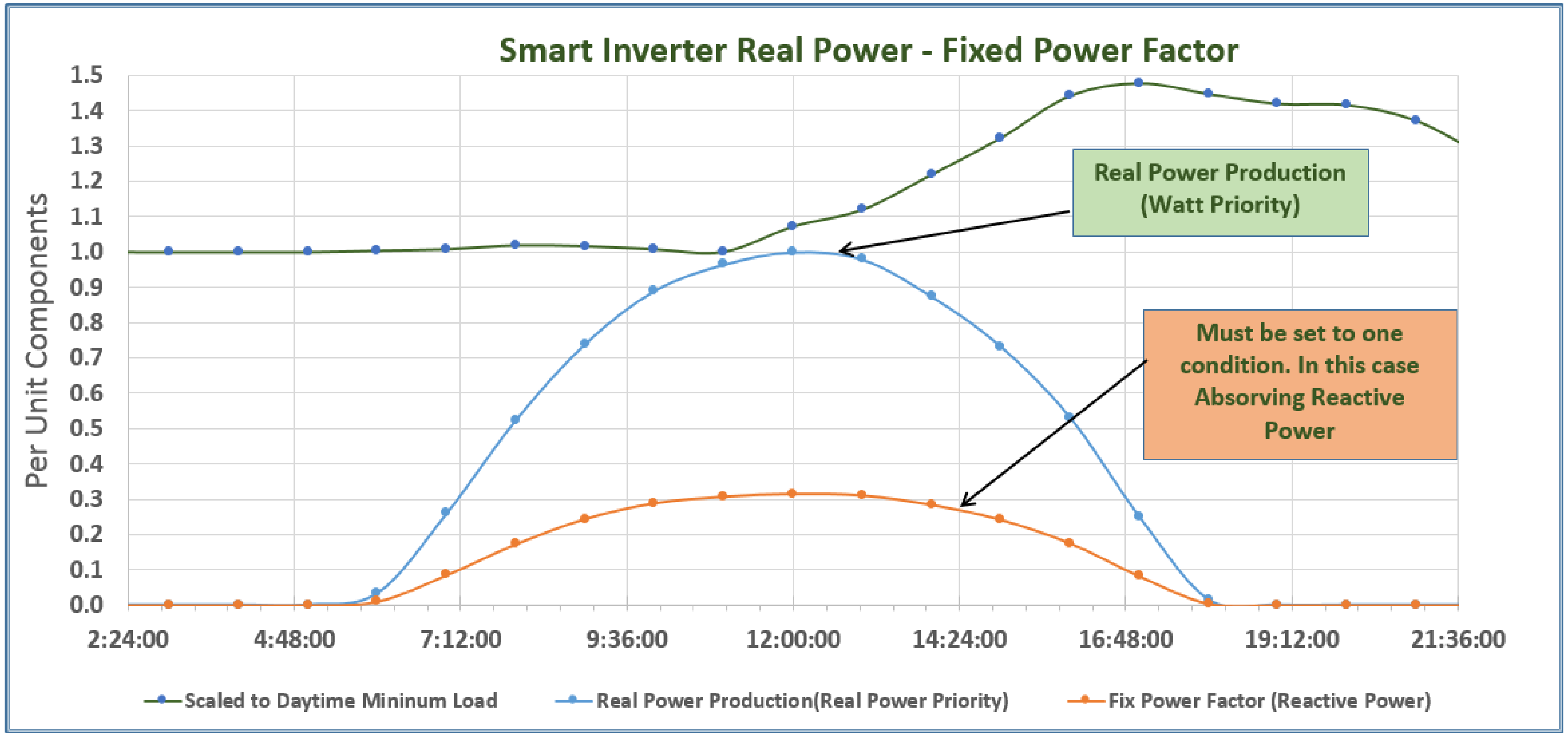


- With typical PV profile and 100% PV-Inverter sizing, the real power output will have a slight reduction in KW output.
- Can mitigate the PV-created high voltage by absorbing up to 30% reactive power
- In aggregate, DER operating in this manner can allow higher level of DER as DER will help mitigate the Steady-State-Overvoltage created by the real power injection to the grid
- Approximately 2% of KW production assuming DC input ins 100%
- There may not be any reduction if DC input is less then 100%
- **SI are not required to support with reactive power needs when real power is less than 20% of SI nameplate**

IOU Recommendation

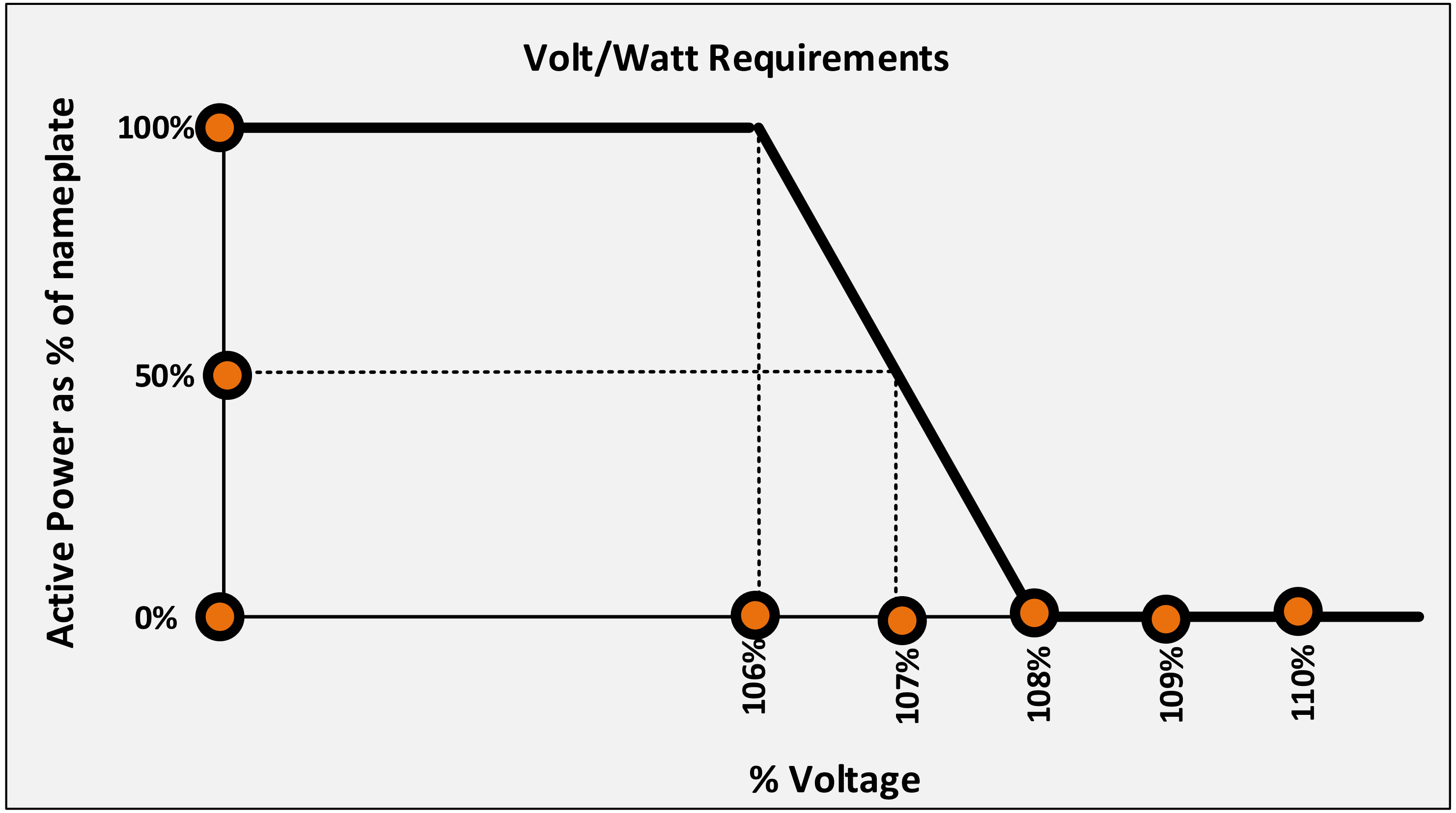
The IOUs believe that the volt/var function with **Reactive Power Priority** can be used to increase ICA at each node.

Fixed Power Factor



- Must be set to a given fixed setting (example is 0.95PF)
- It would always be absorbing (or injecting) reactive power even when not needed potentially creating unnecessary stress on the systems
- Inferior to the utilization of Volt/Var
- Given that we will have Volt/Var available (with reactive power priority), IOUs do not recommend including this function as part of ICA

Volt-Watt



- Function not expected to be available until Q3-2018
- When applied, it will be set with the default settings to only reduce power voltage at voltages greater then ICA limits (ICA uses 105% of nominal)
- Can allow higher level of **connected capacity** as long it reduces the power to the **identified ICA values**

Proposed Recommendation

IOUs to conduct the following:

1. Conduct additional evaluation on the impact to ICA using the proposed Rule 21 Volt/Var curve
   - Only include Volt/Var with reactive power priority
   - Reactive power system flow study- to determine reactive power resource needs (Such new capacitor banks)
2. Conduct additional evaluation on how the volt/watt curve may be used to increase the DER nameplate capacity over the value of ICA
3. Conduct evaluation of the modeling tools and systems (CYME and Synergy) to support the automated process for the two functions into ICA calculations

Deliverable dates :

- Studies to commence Q1 2018
- Studies to complete Q2-2018
  - Findings
  - Implementation needs (what the tools need to do)
  - Implementation plan

System wide implementation of ICA with Smart Inverter to be implemented:

- Q4 – 2018- Q2-2019

Smart Inverters and ICA

ICA Working Group

August 15, 2017

Brad Heavner

CALSEIA

CALIFORNIA SOLAR ENERGY INDUSTRIES ASSOCIATION

High Penetration Benefits

- Reduced voltage constraint (increased ICA) due to presence of smart inverters
- Requires high penetration of inverters
- At least two years out
- Currently only need preliminary discussion of what level of penetration will be needed to achieve this benefit

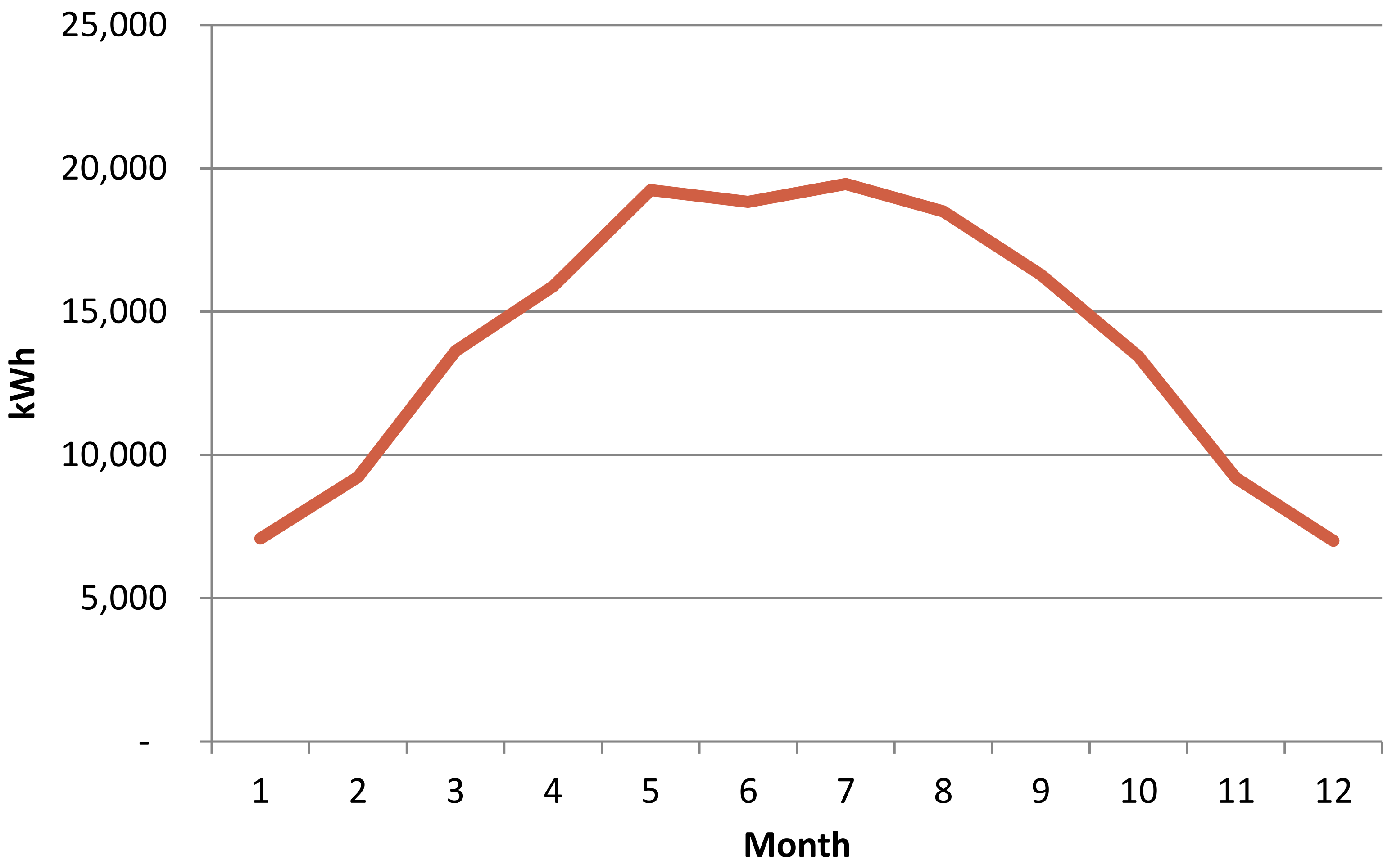
Immediate Benefits

- DERs with inverters with Phase 1 functions will be able to compensate for some of the voltage impacts of the DER.
- ICA should take this into account immediately
- Working Group should identify how much voltage support can be relied on from Volt/Var with active power priority and no headroom in inverter nameplate capacity

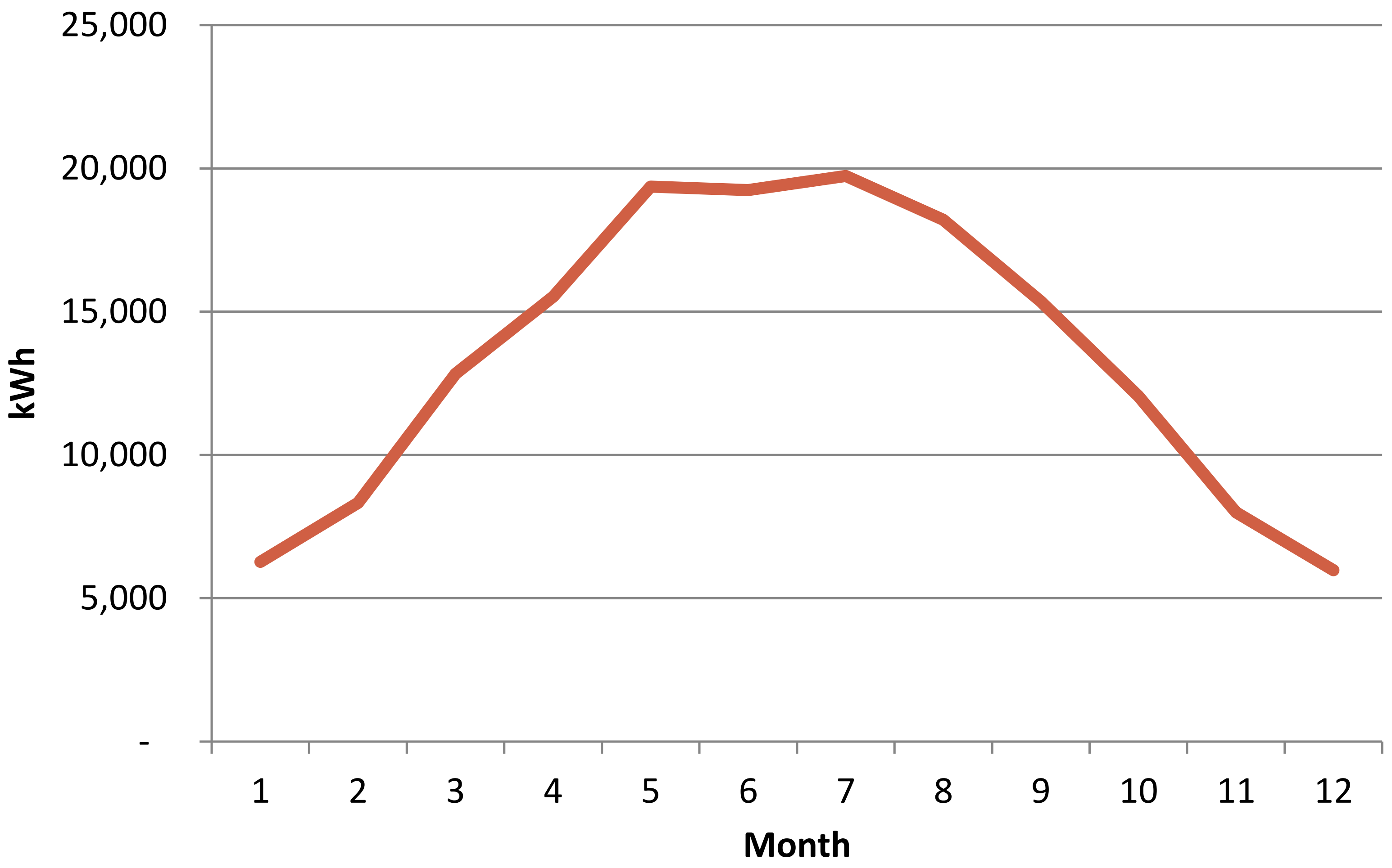
Scheduling

- Systems that would exceed limits in certain hours of the year can schedule curtailment to avoid constraints and install a larger system than would be possible under standard PV profile
- Requires scheduling function being developed in SIWG Phase 3
- ICA Working Group should have a technical conversation of how scheduling will work in the context of interconnection.

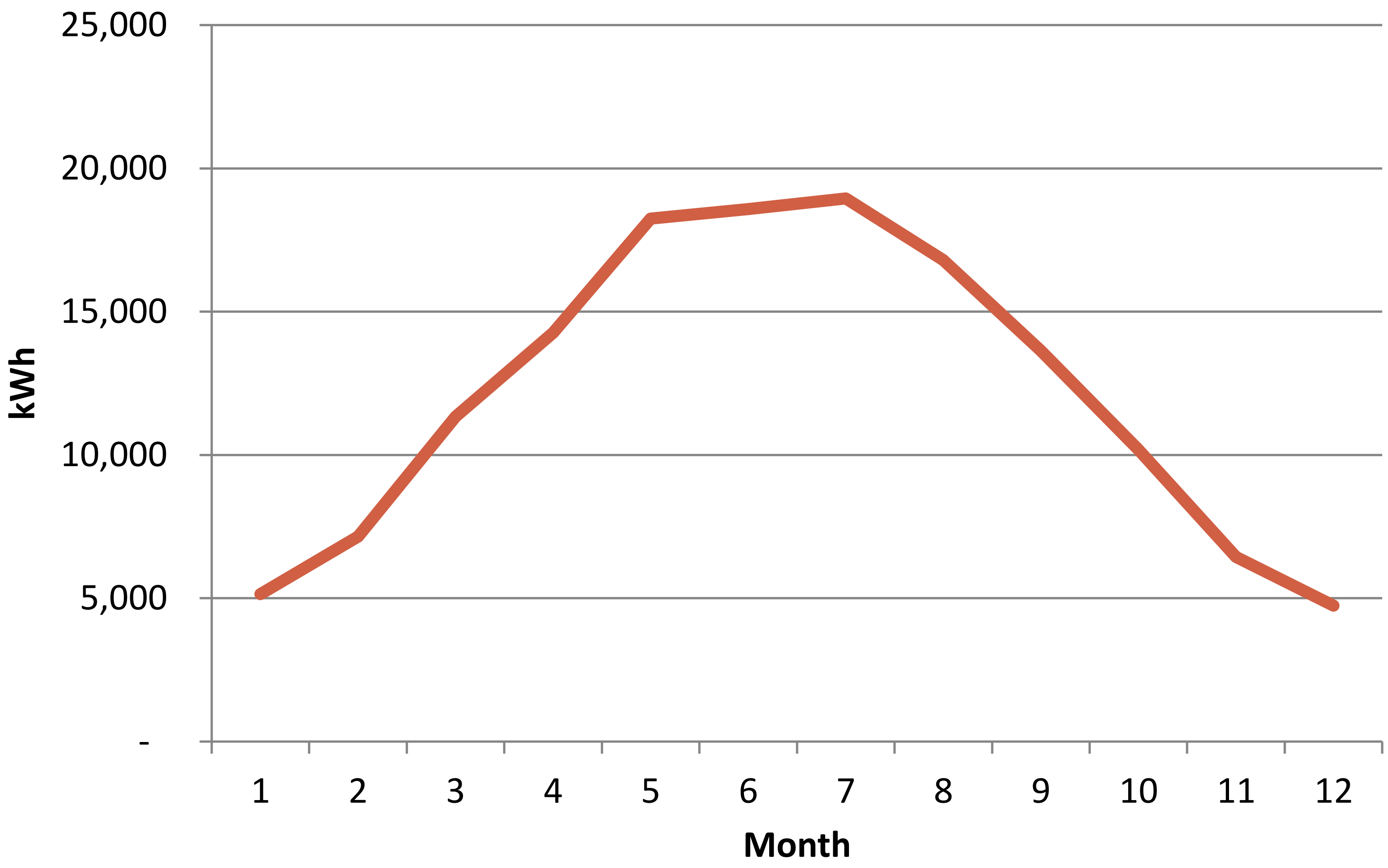
Monthly Production from 100 kW Solar System in Sacramento – South Facing, 20 Degree Tilt



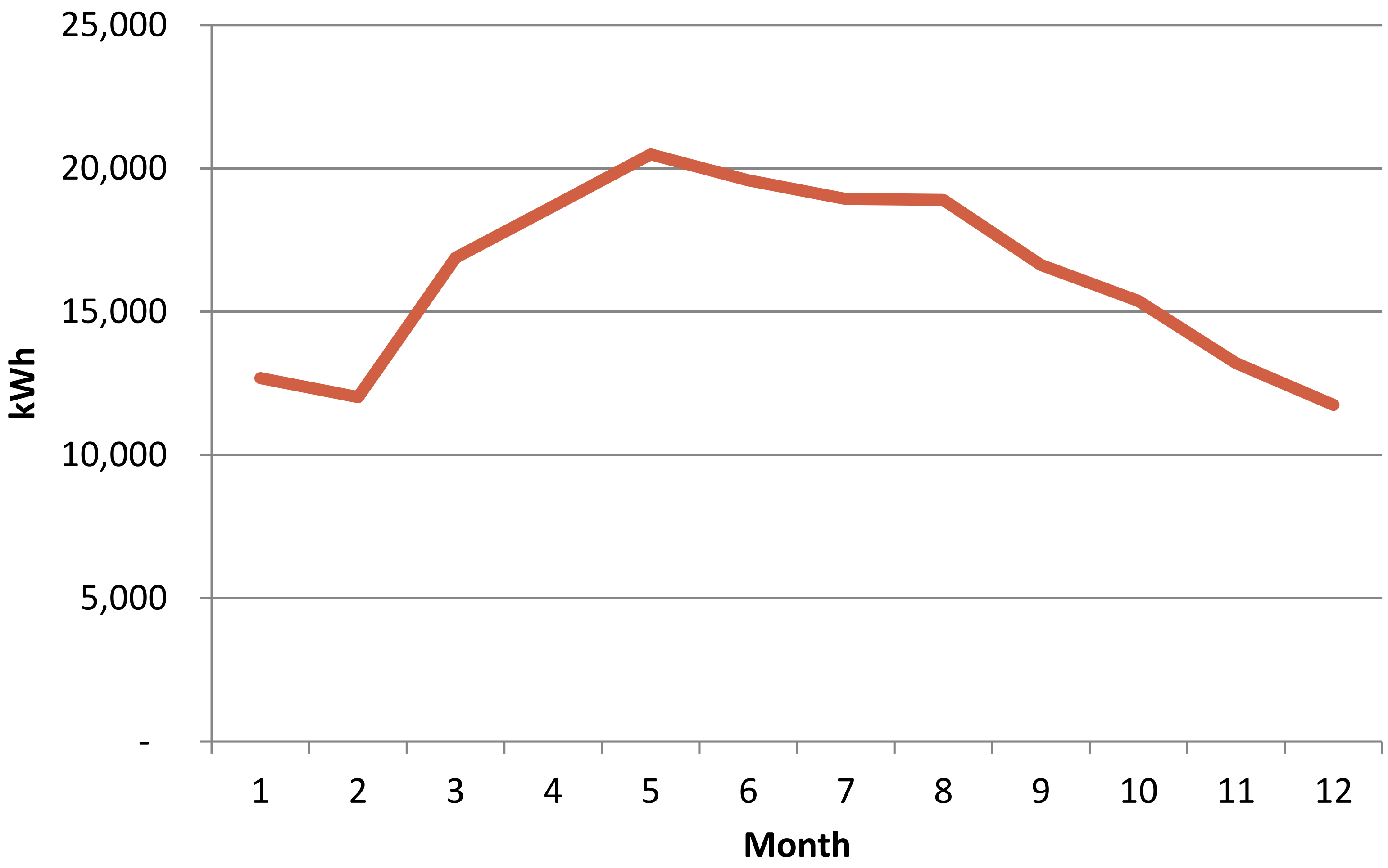
Monthly Production from 100 kW Solar System in Sacramento – South Facing, 10 Degree Tilt



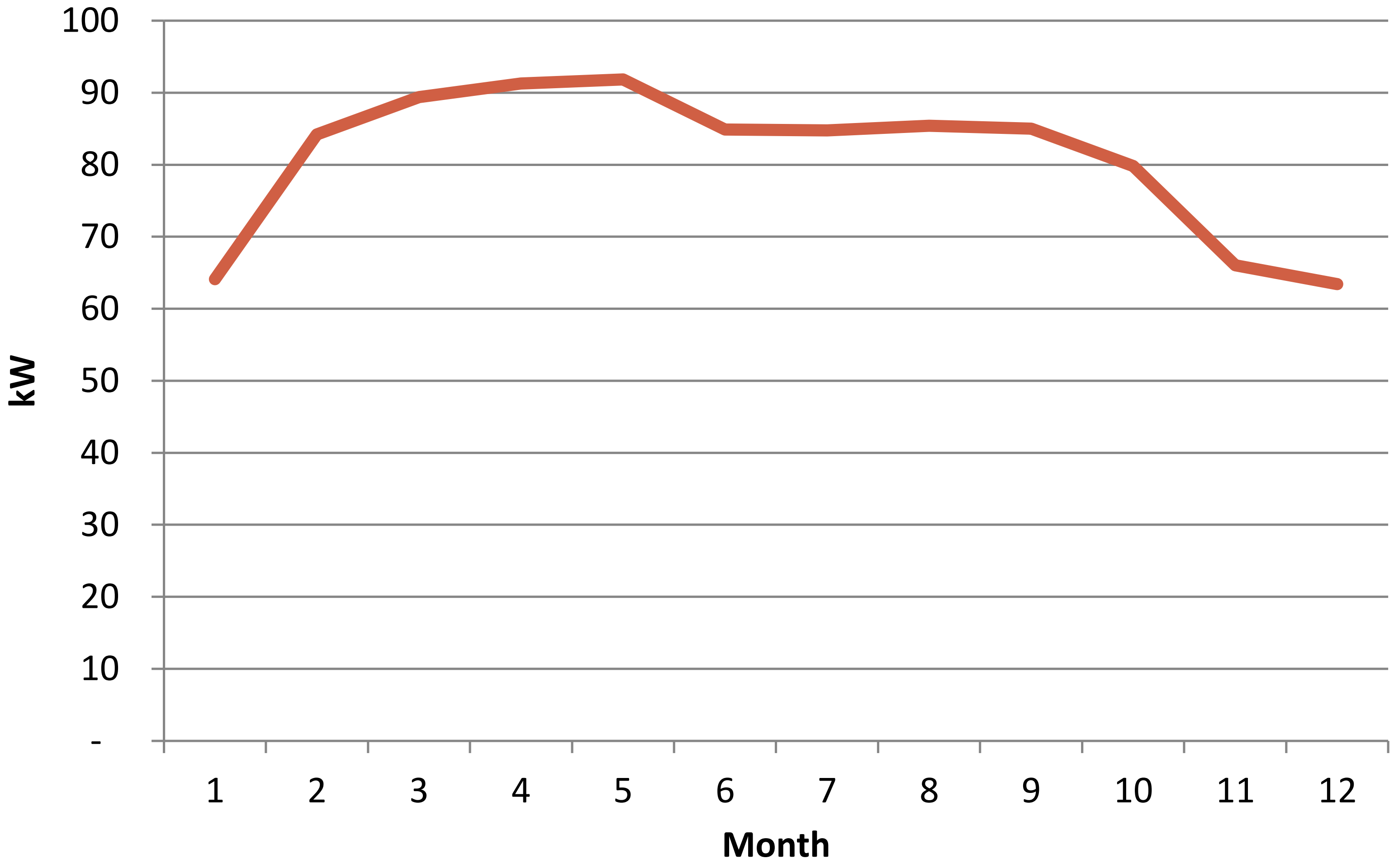
Monthly Production from 100 kW Solar System in Sacramento – West Facing, 20 Degree Tilt



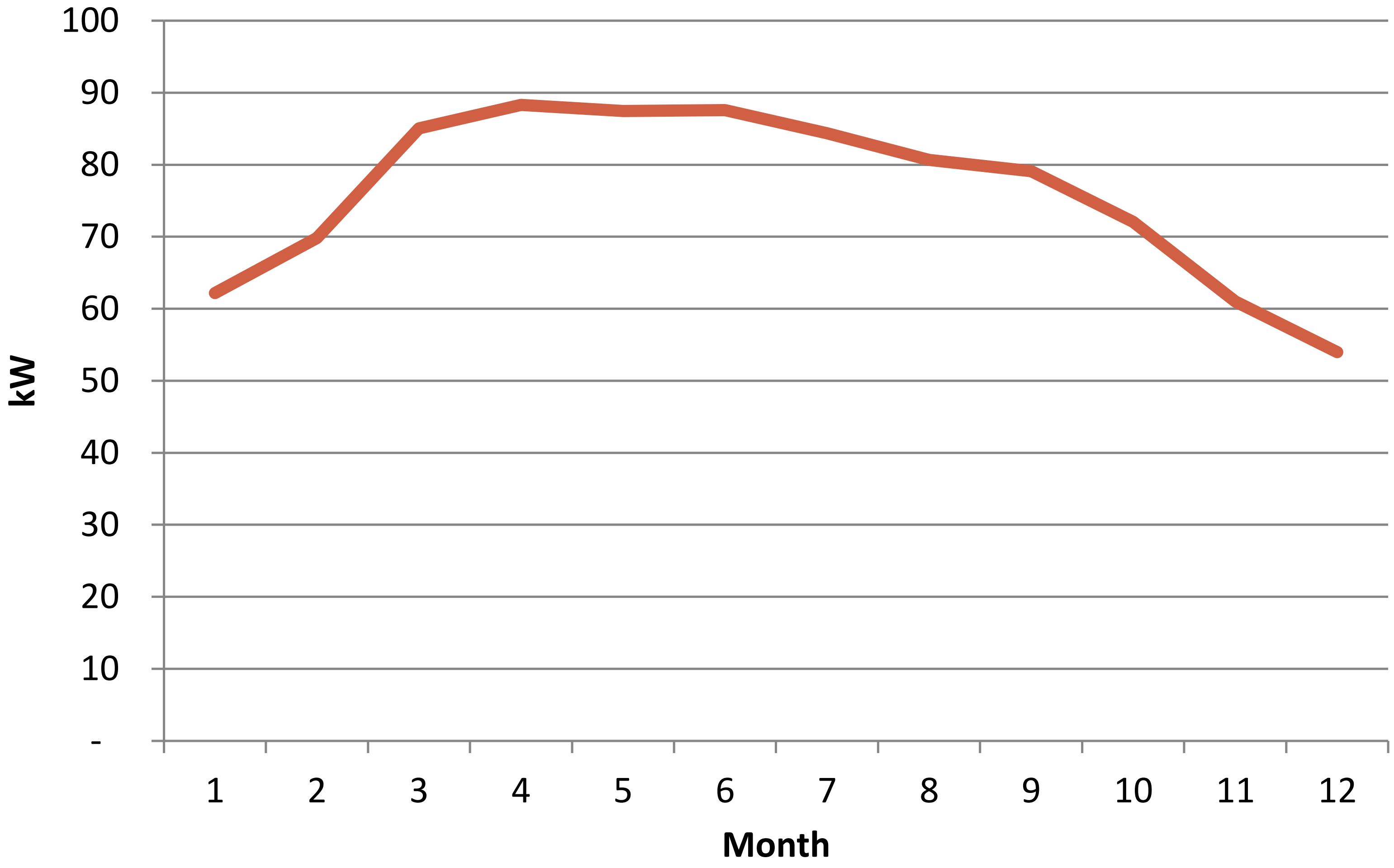
Monthly Production from 100 kW Solar System in Lancaster – South Facing, 20 Degree Tilt



Monthly Maximum Generation from 100 kW Solar System in Sacramento with 20 Degree Tilt



Monthly Maximum Generation from 100 kW Solar System in Sacramento with 10 Degree Tilt



System Losses

Parameter	PV-Watts Default
Soiling	2%
Shading	3%
Mismatch	2%
Wiring	2%
Connections	0.5%
Initial Degradation	1.5%
Nameplate Rating	1%

Lunch Break

August 15, 2017

In-person meeting

drpwg.org

Locational Net Benefits Analysis Working Group

August 15, 2017

In-person meeting

drpwg.org

MORE THAN SMART

Agenda

Time	Topic
1:00 – 1:15	A. Introduction, agenda, July recap, review of August 31st status report
1:15 – 2:00	B. Smart inverters
2:00 – 3:45	C. Locational value for capacity D. Locational value for line losses
3:15 – 4:00	E. Wrap up and next steps

LNBA Working Group

Group	Items: Explanations/Clarifications	Source (ACR/WG report)	Meeting date
I	Item B: methods for valuing location-specific grid services provided by advanced smart inverter capabilities	ACR	8/15
	Item D: Method for evaluating the effect on avoided cost of DER working "in concert" in the same electrical footprint of a substation (same as Item 2.ii)	ACR	7/7
	Item 2: 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; iii) Allowing hourly VAR profiles	WG Report	7/7
	Item 4: Incorporate additional locational granularity into energy, capacity, and line losses system-level avoided cost values	WG Report	7/7 8/15
	Item 5: Form technical subgroup in LT refinements to develop methodologies for non-zero location-specific transmission costs (requires coordination/co-facilitation with CAISO)	WG Report	7/7

Items 2, 4, and 5 should constitute WG primary focus

LNBA Working Group

The Interim Status Report on Group I topics is due **August 31.**

The ACR specifies that the "Status Reports shall briefly summarize the progress on each of the issues discussed to date and are not to be considered final proposals. Each scope issue should be covered within a maximum of one page."

The status report will include:

- Short description and summary of discussion for each Group I topic
- Written proposals, including edits from WG members
- Presentation slides, meeting notes, and other meeting materials

The status reports are meant to be informal and will be circulated to the DRP Proceeding service list, but not formally filed with the CPUC. MTS will lead drafting and compilation, and will circulate the final on August 31.

MORE THAN SMART

LNBA Working Group

Upcoming schedule for written proposals:

8/15: ICA Meeting and Presentations
8/22: First draft written proposals due
8/29: Edits by WG members due
8/31: Status report due

Written proposals from the 7/7 meeting are online:
http://drpwg.org/sample-page/drp/

MORE THAN SMART

B and 2.iii –Advanced Smart Inverters and Hourly VAR Profiles

- Item B: Smart Inverter
  - "Methods for valuing location-specific grid services provided by advanced smart inverter capabilities"
- Item 2.iii) Add VAR Profile to LNBA tool
  - 2.iii "Improve heat map and spreadsheet tool by: … iii) allowing hourly VAR profiles to be input in order to capture DERs' ability to inject or absorb reactive power"
- Item 2 is a "consensus recommendation that should constitute the working group's primary focus." Item B is not.

B and 2.iii –Advanced Smart Inverters and Hourly VAR Profiles

- Recap 7/7 LNBA WG Discussion: WG agreed to:
  - Consolidate 2.iii (VAR profiles) under B (Smart Inverters), since ability to absorb/inject VARs is a key Smart Inverter capability
  - Develop VAR profile methods as first smart inverter capability incorporated into LNBA, since it's a priority item.
    1. IOUS to propose tool modifications to include DER VAR profiles
    2. IOUs to propose methods to calculate VAR requirements for voltage support deferrals
  - Address methodologies for additional smart inverter capabilities beyond VAR profiles (e.g. dispatchability) second.

B and 2.iii –Advanced Smart Inverters and Hourly VAR Profiles

- Proposed Tool modifications to include DER VAR profiles:
  - Add hourly VAR profile along with kW profile (DER Dashboard tab)

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

B and 2.iii –Advanced Smart Inverters and Hourly VAR Profiles

- Proposed Tool modifications to include DER VAR profiles:
  - Add hourly VAR requirements along with kW (Area Peaks tab)

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 (Hour										
1/1/1										
1/1/1										
1/1/1										
1/1/1										
1/1/1										
1/1/1										
1/1/1										
1/1/1										

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

B and 2.iii –Advanced Smart Inverters and Hourly VAR Profiles

- Next Step: Proposal for calculating hourly VAR requirements
  - For voltage project deferrals, capture injections/absorptions required to bring voltage into compliance with Rule 2
    - Future LNBA tool input as IOUs develop time series load flow software capable of providing forecasted VAR profile needs
  - DERs will have to comply with Rule 21 power factor (PF) constraints
    - Will always have both real and reactive power contribution
  - Develop VAR requirements assuming that DERs operate at the edge of the Rule 21 PF constraints to enable modeling both active and reactive contributions' effect on voltage

B and 2.iii –Advanced Smart Inverters and Hourly VAR Profiles

- Other smart inverter capabilities to be considered after Group I priority items:

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

SEIA Perspective on Smart Inverter Functions

Brandon Smithwood, SEIA
Damon Franz, Tesla

August 15, 2017

Smart Inverter Enabled Locational Benefits

1) Avoidance of investments needed to maintain voltages within Rule 2 limits
2) Enhanced Conservation Voltage Reduction
3) Data Services/Situational Awareness (June 7th ACR Group 3 item)

Avoidance of Investments to Maintain Voltages within Rule 2 Limits

- Value: DERs can avoid investments in voltage management equipment
  - Equipment:
    - Load tap changers
    - Capacitors
    - Line regulators
    - Line reconductoring
- There is a need for a 8760 VAR profile to capture ability of inverters to manage voltage through production or absorption of reactive power
  - Currently the LNBA only captures voltage management benefits that come from reducing load
  - SEIA is looking forward to the IOU’s development of this VAR profile

Conservation Voltage Reduction (IOU Positions)

- PG&E:
  - **Quantifying this potential additional savings on any particular circuit requires understanding the extent to which CVR has already been achieved under standard practice.** Any incremental CVR benefits beyond standard practice are highly dependent on a variety of factors specific to that circuit and the customer end use devices that are on that circuit.
  - One simple method to estimate CVR energy savings is to use the CVR factor, which is the ratio of percent energy savings to percent voltage reduction: [percent energy savings] = [CVR Factor] x [percent voltage reduction]. (PG&E DRP Demonstration B Final Report, P. 15)

Conservation Voltage Reduction (IOU Positions)

- SCE:
  - **SCE needs to perform detailed engineering analysis and field research which involve extensive testing over an extended period of time in order to accurately evaluate the benefit** of CVR and/or VVO in its own system. In addition, **necessary communications and controls will be required to enable the functionalities** and full benefits of the program. Therefore, CVR and VVO are not currently estimated or otherwise included in Demo B LNBA values. (SCE LNBA Demo Final Report, P. 16)

Conservation Voltage Reduction (IOU Positions)

- SDG&E
  - Additional CVR-based energy consumption reduction beyond that achieved by standard practice may be achieved by more sophisticated voltage controls, such as those that enable VVO. The problem with crediting DERs for avoided costs through CVR, however, is twofold. First, **quantifying the potential savings on any particular circuit requires thorough knowledge of how voltage level effects consumption which is highly dependent on a variety of factors specific to that circuit and the customer end use devices that are on that circuit.** Second, to achieve CVR**, DERs must be working in concert and be coordinated with utility devices; so CVR is a service that DERs individually cannot effectively provide.** In addition to this, the avoided costs are mainly on the customer end and are not incremental investments. **The two benefits would include the minor reduction in capacity constraints and the small reduction in losses due to less demand, which to accurately calculate would require rigorous dynamic powerflow studies.** (SDG&E DRP Demonstration B Final Report, P. 12)

Rebuttal to IOU Arguments on CVR

- Lack of modeling for greater granularity of CVR benefits does not mean this value should be assumed to be zero
- The value is not *de minimus*: range of values from 1-3c per kWh of generation for PV systems at the end of circuit
- This value has been demonstrated on PG&E and HECO distribution system models
- Communications and control are not necessary: benefits can be realized through inverters set to dynamic volt/VAR acting autonomously

Conservation Voltage Reduction

- Should be considered a system-wide value rather than a locational value
  - Value is avoided energy and line losses
  - Will vary by location, but limitations of secondary system modeling require an averaged, if more conservative, calculation
- Should be calculated by summing incremental avoided energy and line losses

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

Data backhaul/situational awareness

- This value will be discussed in the DRP Working Group as part of the Group III items identified in the June 7th Assigned Commissioner's Ruling
- Distributed energy resources collect a substantial amount of data at a nodal level, including data collected from smart inverters
- This data can be transmitted more frequently than utility data and aggregated and analyzed for utility use
- The value of this service could be calculated as the avoided cost of the utility-owned equipment that would otherwise be installed to provide the service.

Item 4.ii – Locational Avoided Capacity

- June 7 ACR:
  - “Incorporate additional locational granularity into … Capacity”
- MTS Scoping Document:
  - “The LNBA WG was in consensus recommendation to update energy, capacity and line loss avoided costs with more location-specific values. IOUs may update the tool using known values for energy and capacity.”
- Item 4 is a “consensus recommendation that should constitute the working group’s primary focus.”

Item 4.ii – Locational Avoided Capacity

- Demo B LNBA Tool currently uses the 2016 DERAC avoided generation capacity value
  - 2016 DERAC uses the Cost of New Entry (CONE) for a hypothetical new Combustion Turbine (CT) to calculate avoided generation capacity
  - CONE is the "levelized capital cost of a new simple cycle CT unit less the margin that the CT could earn from the energy an ancillary service markets."[1]

$$CONE = CT\ Capital\ Cost - (Energy\ Revenue + Ancillary\ Service\ Revenue)$$

  - CONE represents the maximum avoided cost for generation capacity, which isn't considered to vary across the system

1 "Avoided Costs 2016 Interim Update," Energy and Environmental Economics, Inc., August 1, 2016.

Item 4.ii – Locational Avoided Capacity

- The best available locational generation capacity data is in the CPUC RA Report. This data is applicable to short-term RA prices in LCR areas, not CONE.

Table 8. Capacity Prices by Local Area, 2016-2020

	LA Basin	Big Creek/Ventura	Bay Area	Other PG&E Area	San Diego-IV	CAISO System
Contracted Capacity (MW)	113,124	36,818	83,144	2,657	28,165	40,776
Percentage of Total Capacity in Data Set	37%	12%	27%	1%	9%	13%
Weighted Average Price ($/kW-month)	$3.62	$3.61	$2.20	$2.09	$4.06	$2.44
Average Price ($/kW-month)	$3.45	$3.03	$2.07	$2.06	$3.73	$1.82
Minimum Price ($/kW-month)	$0.75	$0.85	$0.63	$0.80	$0.27	$0.15
Maximum Price ($/kW-month)	$6.43	$4.34	$4.81	$2.80	$26.54	$5.80
85% of MW at or below ($/kW-month)	$3.65	$4.34	$3.00	$2.50	$4.33	$3.00

http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442453942

Item 4.ii – Locational Avoided Capacity Proposal

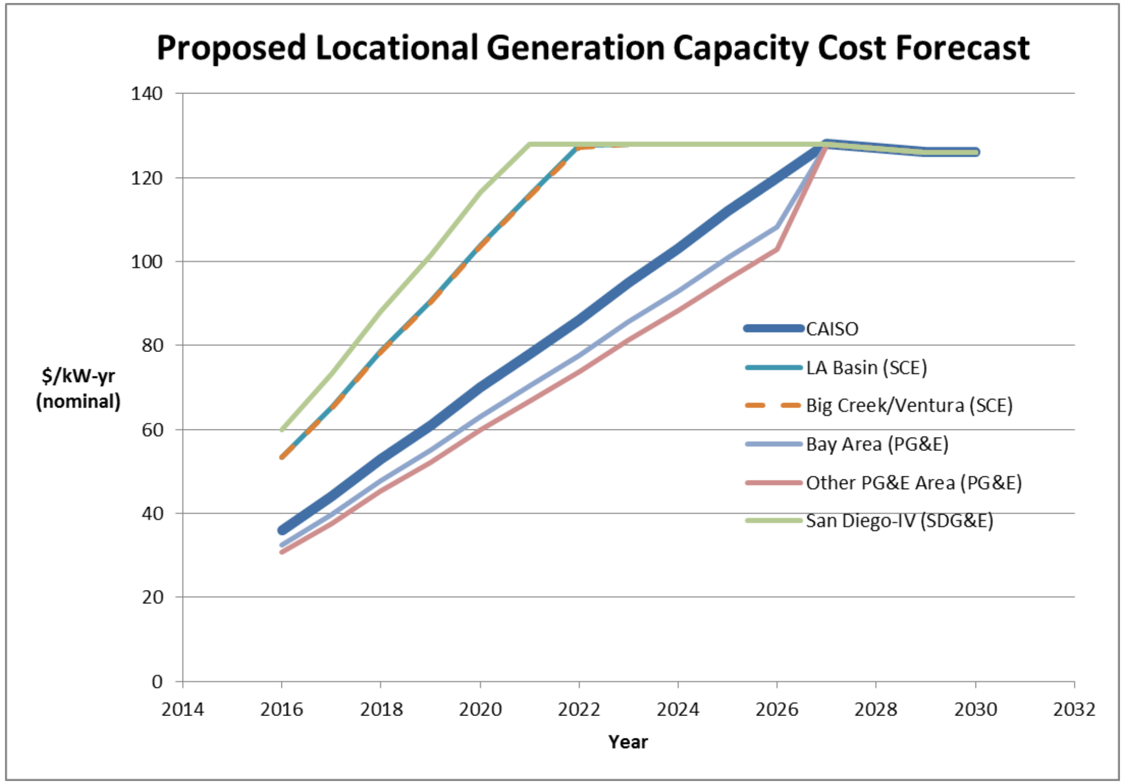
- Develop LCR multipliers using RA Report data and apply these to short-run generation capacity prices in a CAISO system generation capacity price forecast.
  - Each resulting local generation capacity price forecast is capped at the long-run CONE.
  - All LCR areas hit CONE in the base-forecast RBY
  - Proposed CAISO system generation capacity price forecast is the 2016 joint IOU "benchmark" forecast filed in the RPS proceeding, which was calculated using the E3's 2015 SGIP avoided cost tool with updated assumptions. Located here: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M168/K107/168107777.PDF
  - If adopted in IDER, the commission would have to modify D16-06-007

Item 4.ii – Locational Avoided Capacity Proposal

- LCA Multipliers:

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

- Resulting Locational Generation Capacity Cost Forecast:



Locational Net Benefits Analysis (LNBA) Working Group

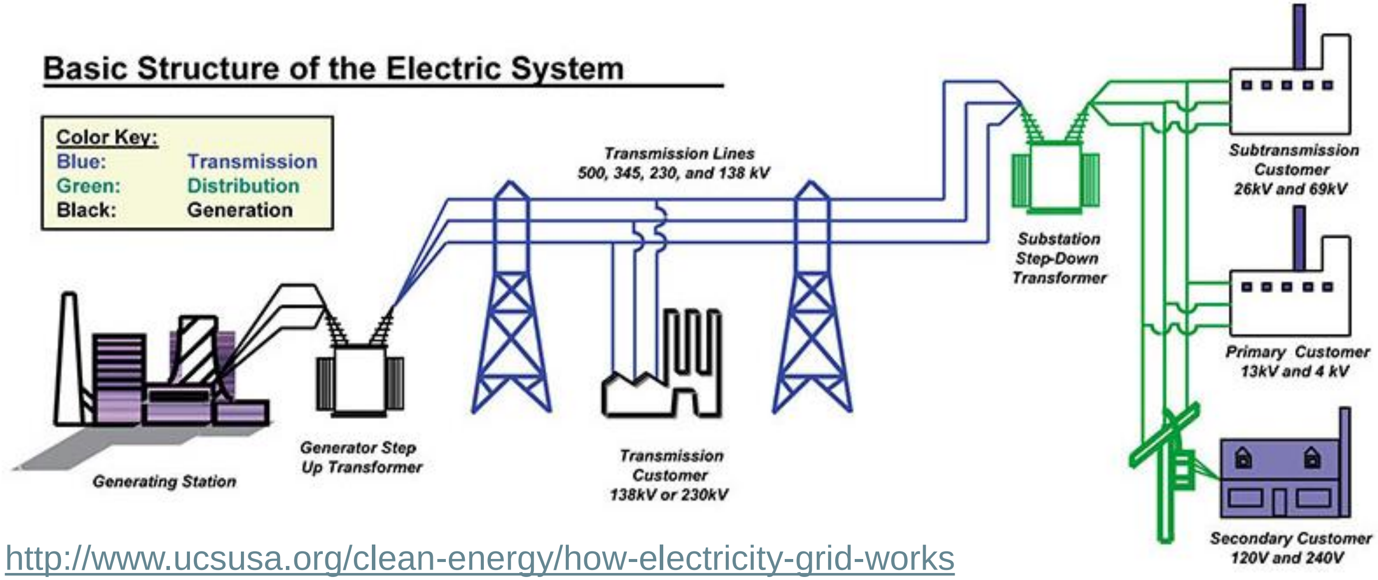
IOU Slides
August 15, 2017

Item 4: Line Losses

- Group 1, Item 4:
  - "Incorporate additional locational granularity into Energy, Capacity, and Line Losses system-level avoided cost values"
- WG Final report:
  - "WG proposes that first step should be to estimate the variability of this parameter across the system to understand the benefits of enhancing the LNBA in this way vs the cost"

Defining Losses

- Transmission System Losses
- Subtrans Losses (SCE only)
- Primary Distribution Losses
- Secondary Distribution Losses
- Export Losses



http://www.ucsusa.org/clean-energy/how-electricity-grid-works

Total losses typically are ~10%, and increase with load

Transmission Losses

- Losses from delivering energy from generators on the bulk (CAISO-controlled) system (220kv+) to the IOU controlled system.
- For PG&E and SDG&E, these are losses from the CAISO system to the high side of the distribution transformer (e.g. 66/69kv-15/12/4/2.4kv).
- For SCE only, these are the losses to the high side of the subtrans transformer (frequently 220-66kv, but voltages vary; in some cases it would be the high side of 500kv-115kv transformer).
- **The IOUs propose to maintain existing treatment of transmission losses within each utility's territory.**

Sub-trans Losses (SCE only)

- Losses from the T/D interface as described above (i.e., high side of 500kV or 220kV) to the high side of the distribution transformer (typically 115kV or 66kV, but exact voltages vary).
- **At present, SCE does not have a detailed analysis of losses between sub-trans systems.**

Distribution Losses

- Distribution losses are losses from the high-side of the distribution substation transformer to the customer.
- Distribution losses can vary from feeder to feeder (i.e. comparing total losses getting energy from feeder head to load on two given feeders)
- The distribution losses can vary from section to section on the same feeder (i.e. the energy losses feeding a customer at the feeder head vs end of line).
- Variation is caused by feeder operation (switching configuration), design (conductor type/length/voltage) and loading (magnitude and frequency of loading levels/distribution of load along feeder).
- DERs’ mitigation of distribution losses depends on the services they provide and their location on the feeder relative to customer load and their size.
- A given DER will only reduce losses on the branch line it feeds and the portion of mainline feeder upstream the DER.
- IOUs propose to analyze distribution loss variations to determine the best way to capture distribution loss variation on each system

Export Losses

- For generating resources causing significant backflow , an additional methodology may ultimately be necessary
- When exported energy from a DER causes significant backflow (e.g., backflow on large portion of primary conductor or all the way across the distribution bus), the losses of the exported energy could be significant. It is possible for these losses to potentially be greater than the “regular” losses calculated for a given location.
- Thus, for exporting DERs, these additional losses should be taken into consideration. This calculation would need to consider when the resource is exporting as well as how much backflow there is during this export, to calculate an export loss factor. This loss factor may result in a net negative loss reduction value for large DER generators

Loss Factors in LNBA

Two parts of the LNBA currently use loss factors to calculate avoided cost:

1. **Peak loss factors for Generation Capacity Avoided Cost**
   – Peak loss factors (marginal T&D kW loss factor at peak hour) are used to calculate a DER's generation capacity procurement avoided cost (e.g. **X** MW customer load reduction @ peak = **X***1.10 MW generation capacity reduction).

2. **Energy loss factors for Generation Energy Avoided Cost**
   – Energy loss factors (combined T&D kWh loss factor for annual energy) are used to calculate a DER's energy procurement avoided cost. (e.g. **Z** MWh/yr customer load reduction = **Z***1.10 MWh/yr generation reduction)

A third Loss factor is used to DER minimum size to defer a T&D upgrade:

1. **Project-specific loss factor for DER deferral sizing**
   – DERs can reduce an overload upstream that would otherwise require T&D investment. The relationship between the magnitude of the overload and the size of the DER load reduction depends in part on losses between the DER solution and the overloaded equipment. (e.g. **X** MW customer load reduction on secondary = **X***1.10 MW load reduction at substation transformer during overload).

In the Demo B LNBA tool these calculations use system average loss factors rather than location-specific factors

IOU Proposal

- The IOUs propose that transmission system-level losses not vary by location in LNBA.

- The IOUS propose that the majority of effort to add locational granularity to loss factors be focused on the distribution primary system losses
  - This requires understanding how much each one varies across feeders and line sections, and also understanding how sensitive LNBA results are to this variation.
  - The IOUs propose to further analyze variation in distribution losses – both across feeders and sections - and propose an approach for refining LNBA in the November meeting.
  - The IOUs will seek to capture a similar level of granularity in loss factors, but may take different approaches, due to different modeling tools and system configurations

- The IOUs propose that losses associated with exported energy may also need to be addressed as an LNBA refinement in the future

IOU Proposal

IOUs to conduct the following:

- Research locational variability of line losses on the distribution primary system in relation to main drivers, e.g.
  - Loading/ Load Allocation
  - Feeder length/conductor type/ voltage
- Investigate different line loss methodologies
  - Traditional studies assume one-way power flow
  - IOUs to look at conditions with DER contributing to reverse power flow
  - Develop a streamlined methodology that isn’t computationally intense
- Provide recommendations to working group at completion of the study

IOU Preliminary Line Loss Study Proposal

1. Select a sample size of distribution feeders to evaluate in preliminary study
2. Define circuit types to reflect differing characteristics
   – i.e. Rural large service area, urban small service territory , and suburban medium size territory
   – Uniform loading, spot load, express run circuit
   – High % loaded circuit, medium %. Low %
2. Evaluate base circuit model (w/o DER) for maximum, minimum, and median loading levels to see the baseline %/kW losses on each circuit
3. Model generation on baseline conditions created in #2
4. Record the kW losses from baseline condition determined from #2
5. Calculate maximum losses % change and min loss %
6. Use line loss study results to estimate sensitivity on LNBA results
7. Share results and with CPUC and greater WG on/around November 1 to determine next steps