Capacity Valuation for BTM Hybrid Resources Workshop

November 24, 2020
9:30am - 4:30pm

California Public Utilities Commission

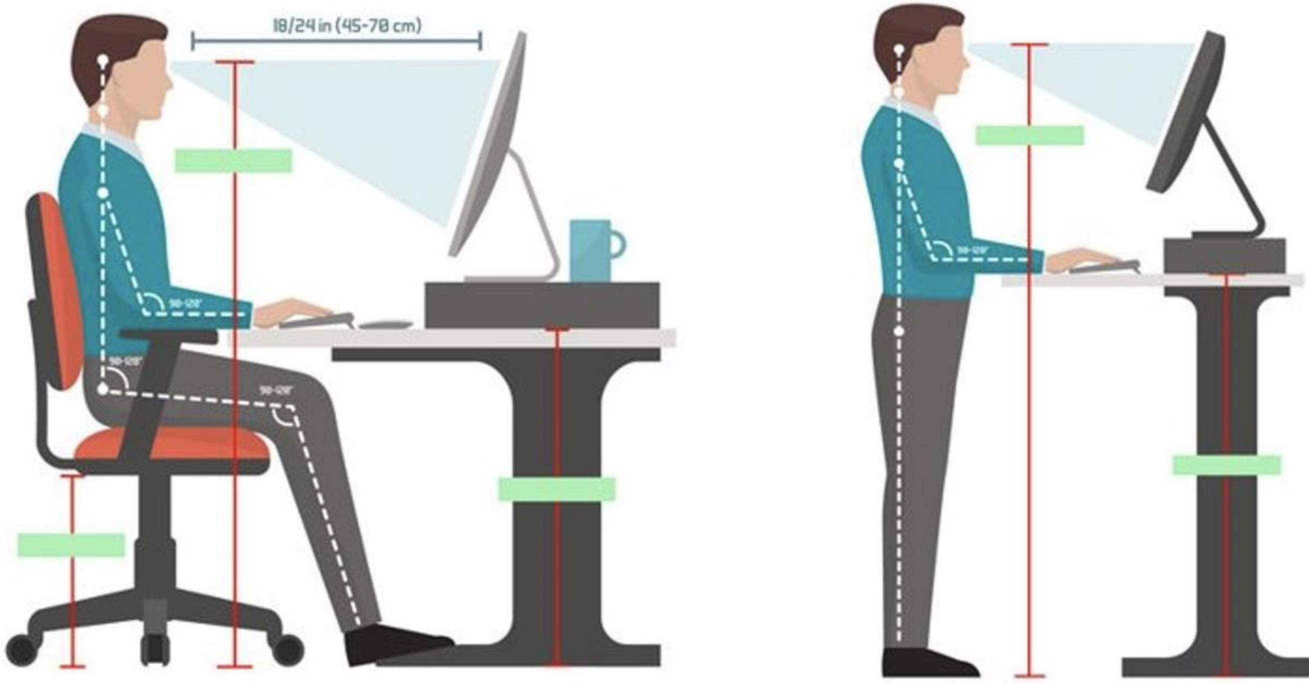
Logistics

- Online and will be recorded
  - Audio through computer or phone
  - Toll-free 415-655-0002 or 855-282-6330
    Access code: 146 465 4461

- Today's presentations & agenda are available on the WebEx link under "Event Material"
- They will be uploaded onto RA history website
  - WebEx password : BTMworkshop
  - Click "View Info" to download

- Hosts (Energy Division Staff)
  - Simone Brant
  - Linnan Cao

- Safety
  - Note surroundings and emergency exits
  - Ergonomic check



Q&A

- All attendees have been muted
- Presenters for each topic will be identified as panelists only when their topic is being addressed
- To ask questions please use the "Q&A" function (send "To All Panelists") or raise your hand
- Questions will be read aloud by staff; attendees may be unmuted to respond to the answer. (Reminder: Mute back!)

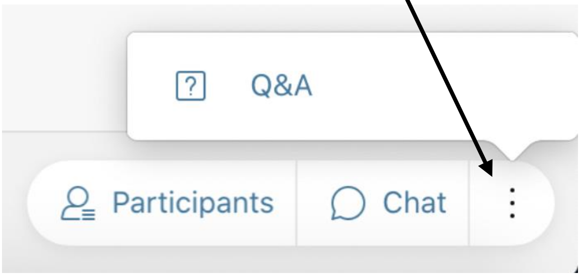
Mute/ Unmute

Participant List

Chat

Audio Options

"Q&A": on the bottom right of screen, click "3 dots"



Ground Rules

- Workshop is structured to stimulate an honest dialogue and engage different perspectives.
- Keep comments friendly and respectful.
- Please use Q&A feature only for Q&A, or technical issues.
- Do NOT start or respond to sidebar conversations in the chat nor Q&A.

Agenda

Time	Panel Topic
9:45 - 10:35 am	1. Overview of Capacity Valuation of Behind the Meter Resources: Obstacles and Opportunities
10:35 - 11:35 am	2. Supply-Side Path Options: Historical approaches and challenges
11:35 - 11:50 am	STRETCH BREAK
11:55 am - 12:50 pm	3. Examination of Load Modifying Demand Response
1:00 - 2:00 pm	LUNCH
2:00 - 3:45 pm	4. Stakeholder Panel
3:45 - 4:30 pm	Final Q&A and Public Comment

Overview of Capacity Valuation of Behind the Meter Resources: Obstacles and Opportunities

Panelists:

CPUC: Comr. Randolph; Simon Baker, Director of Cost, Rates & Planning

CEC: Comr. McAllister

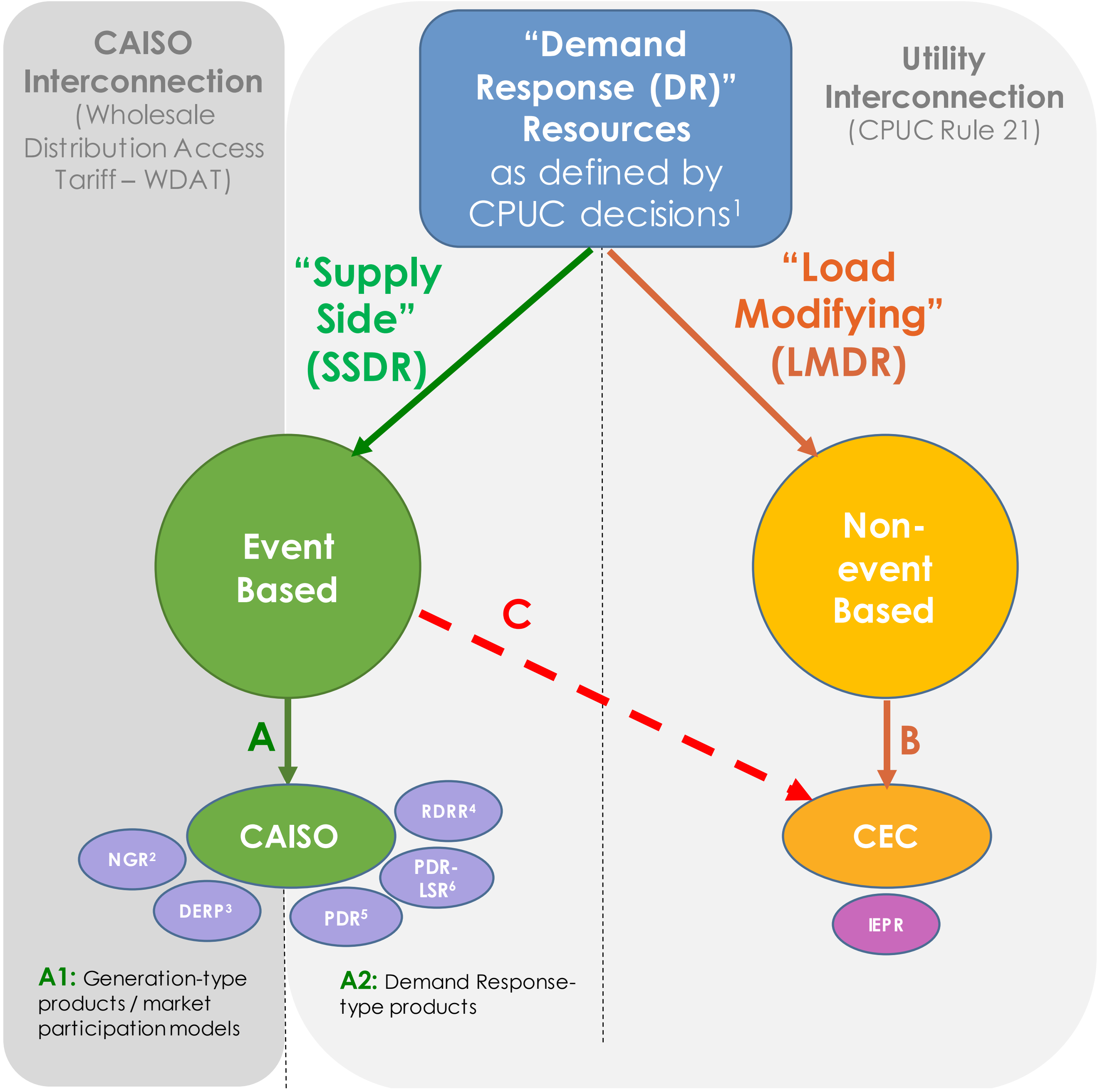
CAISO: Chair Galiteva; SVP&COO Mark Rothleder

9:45-10:35 a.m.

Introductory framing on possible "pathways" for counting BTM RA resources

Simon Baker
Energy Division
November 24, 2020

California Public
Utilities Commission



BTM storage + solar issues:

- Industry seeks "capacity value" for exports
- CAISO established Path A1 for exporting DERs
- CAISO (and CPUC) established Path A2 for non-exporting DERs, measured at the customer meter
- Industry contends Paths A1 and A2 have limitations by design
- Industry advocates for changes to Paths A1/A2 or establishing a new Path C

Key Questions:

- From DER industry perspective, what are the potential challenges in using the existing pathways and available CAISO products?
- What would it take for the industry to use these existing pathways?
- If the event-based LMDR (Path C) were to be explored, what issues would need to be resolved?

[1] CPUC Decisions (D.)14-03-026 and D.14-11-042; [2] Non-Generator Resource; [3] Distributed Energy Resource Provider; [4] Reliability Demand Response Resource (emergency-triggered DR); [5] Proxy Demand Resource (economically triggered DR); [6] Proxy Demand Resource-Load Shift Resource

Panel 1:
Overview of Capacity Valuation of Behind the Meter Resources: Obstacles and Opportunities

Panelists:

CPUC: Comr. Randolph; Simon Baker, Director of Cost, Rates & Planning

CEC: Comr. McAllister

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9:45-10:35 a.m.

Panel 2:
Supply-Side Path Options: Historical Approaches and Challenges

Panelists:

Jill Powers, Manager, Infrastructure and Regulatory Policy, CAISO

Eric Little, Principal Manager, CAISO Market Design, SCE

10:35 – 11:35 a.m.

CAISO Market Participation Models for BTM Resources – Supply Side Path Options

Jill Powers
Infrastructure and Regulatory Policy, Manager

November 24, 2020

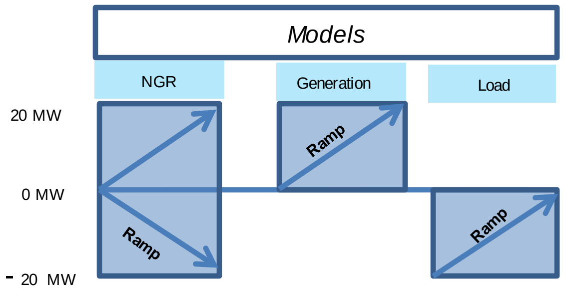
Scope

- Presentation covers:
  - Review of participation models for DERs market participation (facilitating BTM resource market access)
  - FERC order No. 2222 and its impact to current models
  - DER aggregation challenges to wholesale market participation
  - Coordination between Transmission and Distribution Operations with DER deployment and DERA participation
    - need for full DSO to accommodate effectively
  - Bottom up approach to provision of DER services with layered grid interoperability model that avoids “tier bypass”

CAISO DER Participation Models

CAISO participation models are technology neutral and focus on resource capabilities to provide wholesale market services

- Three major categories:
  - Reduces load only
    - Examples include: “traditional” load drop, various demand response programs, storage-backed demand response
  - Generates only
    - Examples include: generation connected at the transmission and distribution level
  - Reduces load and generates
    - Examples include: storage resources, aggregation of distributed energy resources



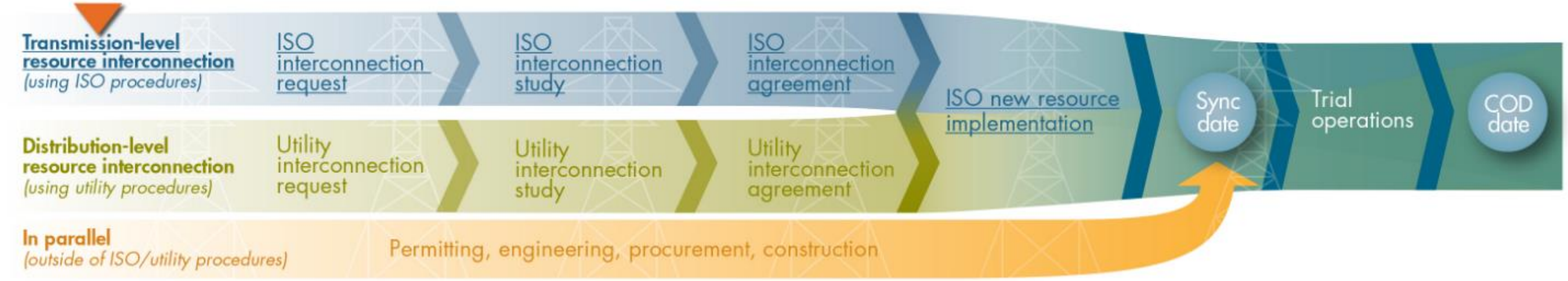
Interconnection processes at the CAISO by resource capability

- Reduces load only

Less detailed **registration** process

- Generates only
- Reduces load and generates

More detailed **interconnection** process



See: http://www.caiso.com/participate/Pages/ResourceInterconnectionGuide/default.aspx

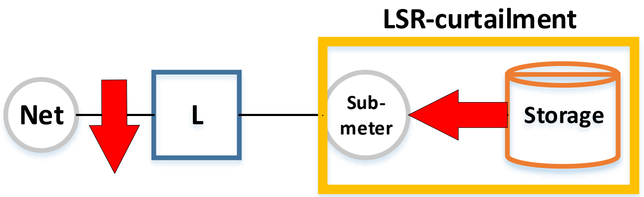
Participation models and their attributes

Model	**Demand Response** (PDR, PDR_LSR,RDRR*) *dispatched only after system warning	**Non-Generating Resource (NGR)**	**Distributed Energy Resource Provider (DERP)**
Market Participation	• Day-Ahead & Real-Time energy • Spinning & Non-Spinning reserves • **Non 24x7 participation** • **5, 15, or 60 minute dispatch option** • Not subject to market power mitigation	• Day-Ahead & Real-Time energy • Spinning & Non-Spinning reserves • **Regulation Up & Down** • 24x7 participation • Not subject to market power mitigation*	• Day-Ahead & Real-Time energy • Spinning & Non-Spinning reserves • **Regulation Up & Down** • 24x7 participation • Not subject to market power mitigation
Capacity & Aggregation Requirements	• Aggregations within same SubLAP • Min 100 kW (for energy) • Min 500 kW (for ancillary services)	• **No aggregations** • Min 100 kW (for energy) • Min 100 kW (for ancillary services)	• Aggregations within same SubLAP • **Min 500 kW *** • **Max <20 MW if across P-Nodes** • **DERs within the aggregation <1 MW**
RA Eligibility & must offer obligation	• **RA eligible – Qualified Capacity methodology exists** • By default, DR resources have a 24/7 MOO • **LRA must adopt terms and conditions for the DR program to modify the 24/7 MOO**	• **RA eligible – requires deliverability study** • 24/7 MOO	• **RA eligible (no tariff rules) – Qualified Capacity methodology does not exist,** requires deliverability study • **MOO (no tariff rules)** – CAISO standard rules may apply
Interconnection Requirements	• **UDC rule 21 requirements** • **ISO registration process**	• **Abide by UDC interconnection (WDAT) for CAISO wholesale participation** • ISO new resource implementation process	• **UDCs may prefer WDAT interconnection, but not required by CAISO/FERC** • ISO new resource implementation process
Metering & Telemetry	• **Baseline (recognizes sub-meter for BTM Energy Storage & EVSE)** • **BTM export of energy not accounted** • Telemetry if >=10 MW, or providing A/S	• **Metered** • Telemetry if >=10 MW, or providing A/S	• **Virtually metered - aggregate of metered DERs** • Telemetry if >=10 MW, or providing A/S

Comprehensive Comparison Matrix available at: http://www.caiso.com/Documents/ParticipationComparison-ProxyDemand-DistributedEnergy-Storage.pdf

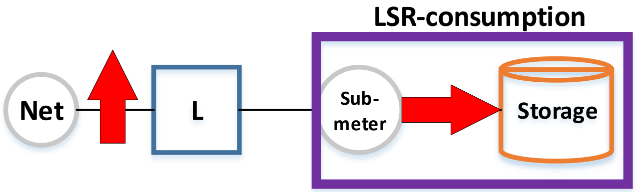
In October, the ISO implemented an enhancement to PDR designed specifically for behind the meter energy storage

PDR Load Shift Resource (PDR_LSR) allows both the curtailment (discharging) and consumption (charging) of load based on market bids.



For load curtailment

- PDR participation attributes maintained



For load consumption

- Ineligible for RA capacity and ancillary services
- Ability to bid a negative cost for energy services
- Pays retail rate for all charging energy

Additional DER aggregation participation requirements

- DERs participating in net energy metering or demand response program are ineligible to participate in a DERA

- Distribution companies get 30 days to review DERAs to ensure DERs are not also demand response participants, net energy metering resources, in other DERAs, conflict with their tariffs, or may pose a threat to safe reliable operation of the distribution system
  - concurrence letter from UDC is required before a DERA can enter the ISO new resource implementation process

FERC Order No. 2222

“Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System”

FERC Order 2222 is largely modeled on the ISOs 2016 DERP filing

Includes requirements that:

1. Allow distributed energy resource aggregations to participate directly in RTO/ISO markets and establish DERAs as a type of market participant;
2. Allow DERAs to register under one or more participation models accommodating their physical and operational characteristics;
3. Establish a minimum size for DERAs that <u>does not exceed 100 kW</u>;
4. Address distribution factors and bidding parameters for DERAs:
5. Establish metering and telemetry for DERAs;
6. Address coordination between the RTO/ISO, the DERA, the distribution utility, and the relevant electric retail regulatory authorities;
7. Address modifications in a DERA; and
8. Address market participation agreements for DERAs.

DERs from utilities with less than 4mm MWh/year ineligible unless allowed by the local regulator

Evaluating model enhancements needed for full compliance with the FERC Order

ISO is continuing its review of FERC Order 2222 against current DERP provisions in preparation for the July 19, 2021 compliance filing due date

- Reducing minimum DERA size requirement of 500 to 100 kW
- Evaluating the need to adjust current aggregation and metering requirements to accommodate baseline measured demand response in a DERA
- Identifying any settlement impact on broader definition of mixed aggregations (energy injections, energy withdrawals and demand reductions)

DERA challenges to wholesale market participation

- Retail programs are more attractive
  - SGIP & NEM (No capacity limit)
  - DERs that could be in DERAs generally are eligible to participate in net energy metering programs
- Stand-alone resource requirements are low
  - 500 kw for generators and 100 kW for storage
- Lack of an established methodology to determine an RA capacity value for DERAs
- Complexity DERAs introduce to distribution system operations and planning

Market participants have been surveyed to gain additional perspective on these challenges

The ISO and distribution utilities formed a working group to address DERA market participation

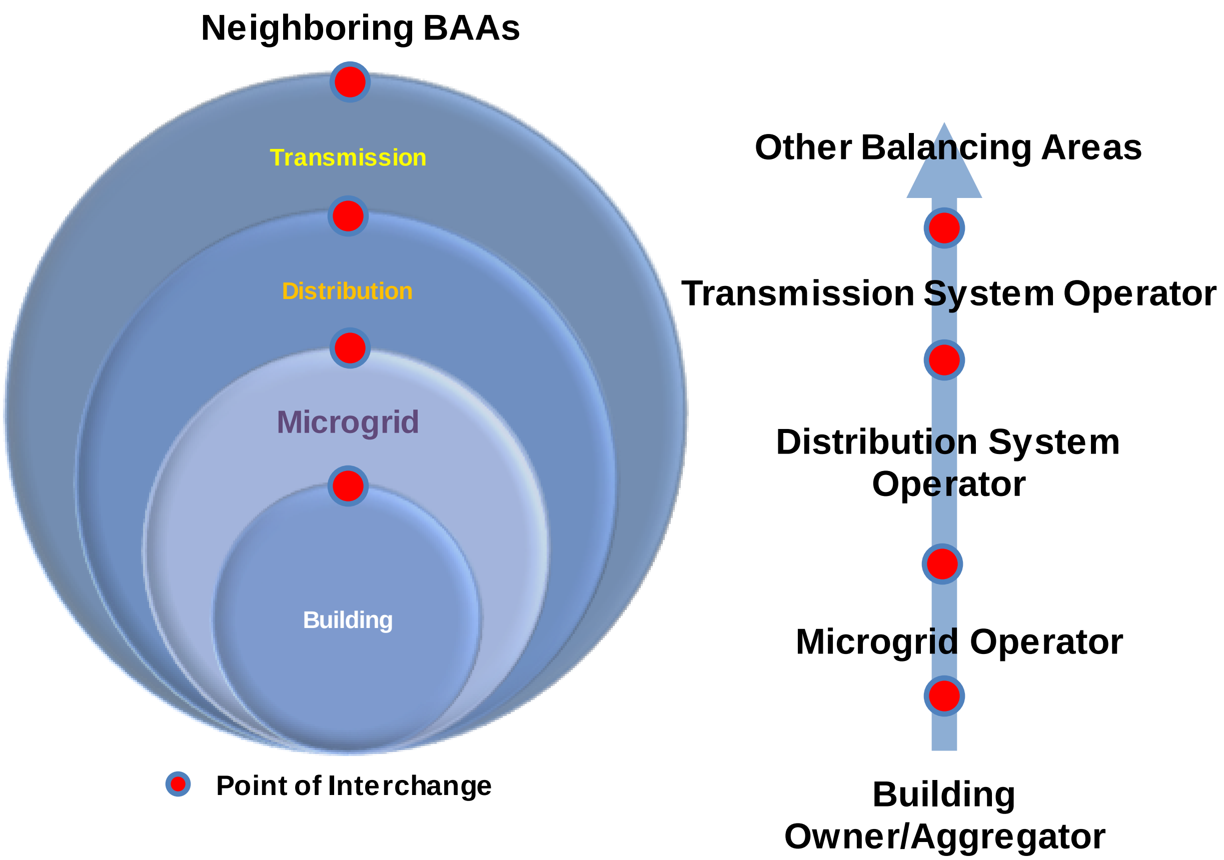
- Distribution Interconnection process did not study DERs impact to system in aggregate
  - established a detailed DERA review process, which included ISO NRI process integration
- ISO market systems see DER at T-D substations, have no visibility to distribution grid conditions or impacts;
  - developed DERA availability (red/green) – manual process
- Distribution utility is not aware of DER bids and dispatches
  - Identified availability to provide information using existing market reporting mechanisms

High DERA participation requires enhanced Transmission/Distribution Operations coordination

Grid Architecture: Layered Grid Interoperability Model

Bottom-up Approach

- Transact for net sales or purchases
- Manage volatility
- Deep situational awareness and control not required
- Layered control structure reduces complexity, allows scalability, and increases resiliency & security
- No tier bypass



A top down, centralized control of an increasingly decentralized system is likely not viable or desirable

Principals Q&A

Until 11:25 a.m.

Public Q&A

Stretch Break :)

Please be back by 11:50 a.m.

Image Source: iamthinks.blogspot.com

Panel 3: Examination of Load Modifying Demand Response

Panelists:

Lynn Marshall, Lead Economist, RA and Demand Forecasting, CEC

Aloke Gupta, Supervisor, Demand Response, CPUC

Delphine Hou, Director, California Regulatory Affairs, CAISO

11:50 – 12:50

Load Modifying Demand Response

Tri-Agency Workshop on Capacity Valuation of Behind the Meter Resources

Lynn Marshall, Energy Assessments Division,
California Energy Commission

November 24, 2020

Event v. Nonevent LMDR

- Event-based programs are those that are dispatched or called when a condition or trigger is met.
  - Estimated hourly impacts of actual events are added back to recorded TAC-area hourly loads to remove these effects from the demand forecast.
  - This avoids distorting hourly load forecast; event-based DR is modeled as a supply resource
  - CPP is dispatched by utilities for various reasons; may not be called on the peak day, or in some months, at all
    - Not included in the CEC hourly forecast, although the monthly peak forecast for CPUC LSEs is adjusted for CPP
    - Some VPP or market-informed use cases also do not fit in the demand forecast
- Non-event-based LMDR systematically modifies consumption in a way that can be forecast, such as time of use rates or real time pricing.
  - Non-event based LMDR becomes embedded in recorded loads.
- CEC only includes non-event LMDR in its hourly demand forecast. Also must be:
  - Reasonably expected (i.e., known funding commitment, observed enrollment trends)
  - Empirical basis for estimating impacts (pilot studies, engineering models validated with performance data)

Non-Event-Based LMDR in the 2019 IEPR Demand Forecast

- To forecast demand at the meter, CEC produces an hourly forecast of consumption and various load modifiers, including PV and battery generation, EV impacts, energy efficiency and climate change, for each TAC area.
- Categories of LMDR included in the adopted **2019 IEPR** Forecast are:
  - Residential transition to default TOU rates. Scenarios use hourly load impact estimates from recent pilot studies, combined with IOUs most recent transition schedules.
  - New EVs adopting TOU rates
  - BTM Battery Storage: residential solar+storage SGIP installations, and nonresidential standalone. Export is not modeled.
    - Data sources are SGIP application data and SGIP Impact Evaluation Reports
    - The SGIP program now requires residential units to be on an eligible TOU rate and report GHG emissions.
    - Residential modeled using NREL System Advisor Model, economically dispatched on time-of-use rate. 2018 SGIP impact evaluation provides hourly dispatch profiles demonstrating that most units on TOU rates are discharging during peak periods.
    - Nonresidential estimated to have minimal coincident peak impacts; past data reflect demand charge management – will be revisited based on new program evaluation data.
    - BTM storage adoptions for 2020 Update are significantly higher: *https://www.energy.ca.gov/event/webinar/2020-11/demand-analysis-working-group-dawg-meeting-california-energy-demand-forecast*

Process for 2021 RA Demand Forecast

- LSEs submit year-ahead forecast and supporting detail for CEC review and adjustment to determine their RA forecast
  - Past practice in both RA and IEPR demand forms has been to request load modifier detail only from IOUs.
  - Commonly forecasted effects such as PV growth have been included as part of IOU RA forecasts
  - CCAs may have these effects embedded in their forecast, and may also be pursuing various demand-modifying programs and activities outside of traditional utility programs
  - For 2021 RA, both IOUs and CCAs were asked for supporting data on load modifiers. Similar changes planned for 2021 IEPR demand forms.
- LMDR that corresponds to CEC forecast categories may be submitted as part of the LSE's year-ahead demand forecast
  - CEC reviews forecast submittal and compares with CEC assumptions. CEC may adjust LSE forecast if needed.
  - If validated, the LMDR will be included in the LSEs final RA forecast, thereby reducing basis for obligation.
  - In future years, these impacts are assumed embedded and are not counted as adjustment.

Supporting Data Requested for RA 2021 BTM Storage

LSE storage use cases comparable to IEPR forecast can be considered embedded in the IEPR forecast. Supporting data is requested for forecasted impacts of new BTM storage additions:

- Power rating, battery and PV capacity, type, configuration (stand-alone/paired)
- Number of new interconnections by sector and Installation timeline
- Dispatch procedure (i.e., bill savings + resiliency)
- Applicable tariff (must be SGIP-eligible)
- Terms of contractual obligation with LSE (commitment to reduce during RA hours)
- Simulated or, if available, historical hourly storage generation output for comparable installations

- LSEs are also required to report the following year:
  - 8760 storage energy stored/discharged and associated load data;
  - Actual interconnections, installed capacity, and deployment schedule
  - SGIP resources also required to participate in SGIP impact evaluation studies

LMDR Forecast Credit Options

- For each RA cycle, CEC can identify and characterize eligible LMDR categories included in the CEC reference forecast. LSEs can include comparable impacts in their submitted RA forecast.
- Options for new load modifying program or tariff:
  1. Submit in IEPR process (LSE's demand forms, DAWG process)

     If adopted, reduces load forecast used for both IEPR system and local, as well RA and IRP forecasts
     - Inclusion would depend on empirical basis and supporting data
     - Not suited for pilot programs
     - Requires earlier commitment
     - CEC forecast would not include export to grid
  2. Load forecast credit after IEPR forecast adoption
     - Would require additional CPUC/CEC process
     - Would need to address incrementality relative to IEPR forecast
  3. Wait for benefits to accrue in recorded loads
     - No data provided to CEC
     - RA benefit lags investment

Demand Forecasting and DR/DER Interactions

- Regardless of pathway, as DER installations increase, CEC's ability to accurately forecast metered load will be challenged without more comprehensive data collection.
  - If resource is in a supply-side program, CEC should be receiving program impacts (charge and discharge) through load impact protocol ex post analysis, but the LIP ex post data do not quantify storage charge/discharge v. load response
  - Ex post impacts are also not available by LSE for any DR program
    - This may be more easily solved for submetered DERs than for estimated behavioral impacts.
  - CEC has no visibility on hourly performance of storage or PV
  - More comprehensive data availability would improve valuation of distributed resources in the demand forecast

Thank You

Lynn Marshall
Lynn.Marshall@energy.ca.gov

BTM Workshop – Load Modifying Demand Response Panel

Aloke Gupta,
Demand Response, Energy Division
November 24, 2020

Agenda

- Existing CPUC DR Policies
- Bifurcation of DR Programs
- VPP Illustration
- Issues to Consider

Primary Pathways for BTM DER Capacity Value

- **Supply-Side Demand Response (SSDR) – Market integrated**
  - CAISO market model: Proxy Demand Resources (PDR)
    - Eligible for RA capacity, but NO capacity value for exports (aka negative loads)
    - Rule 21 interconnection
    - Minimum aggregation ~ 100 kW (for energy market)
  - Alternative market models counting DER exports: NGR & DERP
    - CAISO interconnection
    - Other market and aggregation requirements
- **Load Modifying Demand Response (LMDR)**
  - Limited to the CPUC specified programs*
  - All other event-based resources required to participate in SSDR*

*DR D.15-11-042

Existing Policy Constraints: D.15-11-042

- **All event-based resources should be market integrated (SSDR)**
- **Event-based load modifying resources have no measurable capacity value**
  - "…unless and until a mechanism [satisfactory "hard trigger"] is developed, we conclude that event-based load modifying resources have no measurable capacity value." (p.16)
- **Commission finding: A satisfactory "hard trigger" dispatch mechanism is lacking**
  - "…a hard trigger mechanism that would meet…

    - all the party-suggested parameters as well as

    - an associated nomination and penalty structure

    would be difficult and resource intensive to create and implement…"

Demand Response Bifurcation*

SSDR (Supply Side DR)	LMDR (Load Modifying DR)^

• IOU DR Programs: Capacity Bidding, A/C
• IOU LCR_DR contracts
• DR Auction Mechanism (DRAM)
  ○ Six DR Providers in 2021
• LSE RA_DR contracts
  ○ Three DR Providers qualified via LIPs for 2021
	• Permanent Load Shifting (PLS)
	• Time of Use (TOU) } *Daily*
	• Critical Peak Pricing (CPP)
	• Peak Time Rebate (PTR) } *Event*
	• Real Time Pricing (RTP) — *Hourly*

*DR D.14-03-026 and D.15-11-042
^D.15-11-042 classifies listed programs as "non-event based load modifying programs"

Demand Response Bifurcation*

SSDR (Supply Side DR)	LMDR (Load Modifying DR)^

• IOU DR Programs: Capacity Bidding, A/C
• IOU LCR_DR contracts
• DR Auction Mechanism (DRAM)
  ○ Six DR Providers in 2021
• LSE RA_DR contracts
  ○ Three DR Providers qualified via LIPs for 2021, including BTM Solar + Storage VPP**
	• Permanent Load Shifting (PLS)
	• Time of Use (TOU)
	Daily
	• Critical Peak Pricing (CPP)
	• Peak Time Rebate (PTR)
	Event
	• Real Time Pricing (RTP) — *Hourly*
	• Proposed: BTM Solar + Storage "Virtual Power Plant" (S+S VPP)^^

**Zero capacity value for exports	^^Seeking capacity value for exports

*DR D.14-03-026 and D.15-11-042

^D.15-11-042 classifies listed programs as "non-event based load modifying programs"

Illustrative VPP Proposal

- **A dispatchable BTM Solar + Storage (S + S) VPP**
  1. Not integrated into the CAISO market ("load-modifier" for peak load reduction)
  2. Primary driver for solution likely to be resiliency
  3. BTM S + S connected under R21/NEM ➔ export permit automatically included
  4. Some installations may or may not be SGIP subsidized
  5. Battery sizes ~ typically multiples of 5-7 kW x 10-13 kWh
  6. VPP dispatched via two methods
     a. Load shape: dispatched daily for arbitrage in accordance with customer's TOU rate
     b. Load shed (shift): event-dispatched per Aggregator's forecast of peak load each month
  7. During event, batteries likely to export (relative to house meter)
- **Seeking "capacity value" for exports contributing to an LSE's peak load reduction**

Issues to Consider (Part 1)…

…For LMDR pathway to be made available for BTM S+S VPP:

1. **What requirements should apply to VPP dispatch trigger mechanism?**
   a. A high bar exists per D.11-15-042 (see earlier slide)
2. **Should there be symmetry between SSDR and LMDR resource availability requirements?**
   a. SSDR RA availability requirements: min 4 hour / event, 3 consecutive days, min 24 hours / month
   b. What requirements should apply to VPP availability and events (number, duration, frequency)?
3. **Should battery export (negative load) be included in the capacity value?**
4. **How should capacity value be measured during an event?**
   a. Based on whole premise meter?
   b. Based on direct metering of battery?
      i. Is embedded sub-meter acceptable for measurement & verification?
      ii. Should there be an established meter standard applicable to the sub-meter?

Issues to Consider (Part 2)

5. **Are current Load Impact Protocols (LIPs) adequate to establish ex-ante capacity valuation of BTM S+S VPP resources?**
6. **How should potential double counting issues be resolved?**
    a. What baselines (TOU, SGIP) should be developed and excluded from capacity value
7. **How should the VPP capacity value be counted in the RA-CEC planning framework?**
8. **How should the VPP capacity be handled in the annual process for determining local RA requirements and allocation to LSEs?**
    a. Note: CAISO-proposed changes (PRR 1280) to local RA “crediting” rules would not recognize DR capacity value unless the DR resource is shown on CAISO supply plans
9. **What CPUC oversight should apply to LSE contracts involving VPP load modifiers?**
10. **How should other accountability, reliability, planning, etc. concerns be addressed?**
    a. Such as, penalties for underperformance

California Public Utilities Commission

Aloke.Gupta@cpuc.ca.gov

Panel 3: Examination of Load Modifying Demand Response

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Aloke Gupta, Supervisor, Demand Response, CPUC

Delphine Hou, Director, California Regulatory Affairs, CAISO

11:50 – 12:50

Principals Q&A

Until 12:50 p.m.

Public Q&A

Capacity Valuation for Behind the Meter Hybrid Resources Workshop

Lunch Break until 2:00 PM

Stakeholders Panel

Panel Chair: Ed Randolph, Deputy Executive Director, CPUC Energy Division

Stefanie Tanenhaus, Principal Regulatory Analyst, East Bay Community Energy

Martin Wyspianski, Senior Director of Electric & Gas Acquisition, PG&E

Rachel McMahon, Senior Manager, Public Policy, SunRun

Matthew Tisdale, Executive Director, Gridworks

Stephen Castello, Regulatory Analyst, Electricity Pricing and Customer Programs, CalPA

2 – 3:45 p.m.

EAST BAY COMMUNITY ENERGY

Behind the Meter Workshop

PRESENTED BY: Stefanie Tanenhaus

DATE: November 24, 2020

Guiding Principles

1. Policies and programs should incentivize resource performance consistent with grid needs
2. Reliability contribution of a resource should only be counted once, whether it is load-modifying or supply-side
3. Qualifying Capacity of a resource should be based on its contribution towards meeting system capacity needs, regardless of whether it is in front of or behind the meter*
4. Reliability contribution of contracted load-modifying resources should be credited to individual LSE making investment

*Adjustments (e.g. PRM gross-up) may be appropriate

Incrementality and Double-counting

- How to ensure that the reliability contribution of each resource is only counted once?
  - LSE-specific information required to attribute impacts of BTM DER resources on load-shape
  - CEC collects information on LSE contracts, makes adjustments for incremental effects
  - Supply-side contracted resources are excluded from peak forecast and applied to LSE RA obligation
  - Contractual obligations specify dispatch requirements
  - Performance can be measured

BTM Hybrid QC Methodology

- How should the Qualifying Capacity of BTM Hybrid resources be established?
  - RA Track 2 decision adopted a QC methodology for front of the meter hybrid and co-located resources with ITC restrictions
  - To the extent dispatch capabilities are the same, BTM hybrid resources should be subject to the same QC methodology as FOM counterparts
  - Inability to count grid exports significantly reduces RA value relative to actual reliability contributions

CENTRAL PROCUREMENT OF LOCAL RA AND BTM INVESTMENT

Local RA CPE and BTM Investment

- Central Procurement framework for Local RA adopted in July 2020 to begin for the 2023 compliance year
  - PG&E and SCE to procure all local RA for LSEs in respective territories
- Customers of LSEs making investments in BTM resources, including EE, DR, TOU rates and BTM hybrids, that provide local reliability value are not compensated for offsetting Local RA need
  - BTM peak load-reducing projects become more expensive

Use of CAM Disincentivizes LSE Investment in Load Reduction

- Cost Recovery Mechanism Doesn't Account for Costs Some Customers Incur to Invest in "Avoided RA"
  - EBCE customers invest in peak load reductions, and pay for these investments through their EBCE generation charge
  - EBCE customers' investments reduce PG&E's overall RA need as central buyer
  - Because PG&E's local RA need as central buyer is lowered, all of PG&E's delivery customers pay less through CAM (the benefit of EBCE's customers' investment is socialized across all CAM customers)
- Result: EBCE's customers pay more in EBCE generation rates than they receive as a discount in PG&E CAM charges; they subsidize all other PG&E-area LSE customers

EAST BAY COMMUNITY ENERGY

Potential Cost Recovery Solutions

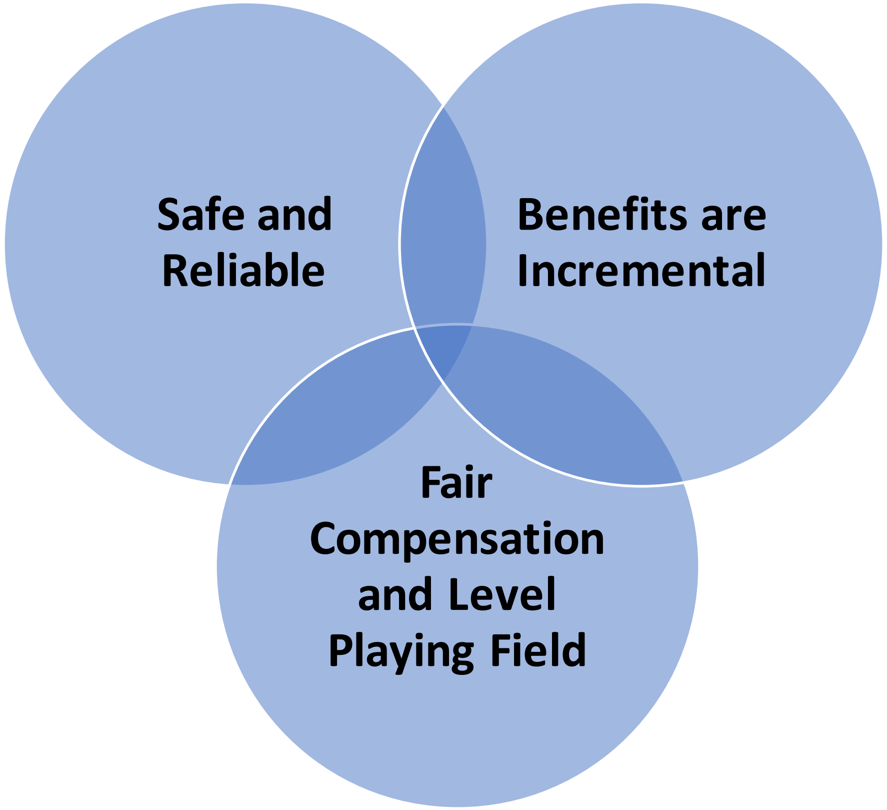
1. Instead of using CAM, Central Buyer bills the LSE directly for its peak load share of local RA; LSE then bills its own customers in its generation rates
2. Central Buyer bills customers directly via a new central buyer RA generation charge based on each underlying LSE’s peak load share
3. Central Buyer differentiates the CAM charges based on the underlying LSE's peak load share. Drawback: distorts rate comparisons because LSE's generation rates will be higher, but at least total customer bills will not.

The key to any of these approaches is that the LSE's customers pay the costs of peak load reductions but get the **full benefit** of reduced share of local RA costs

EAST BAY COMMUNITY ENERGY

Guiding Principles

- The IOUs are supportive of greater integration of BTM resources into CAISO markets and the RA program if the following **guiding principles** are followed:



Key Issues

- **Compensation for BTM Resources**:
  - Incrementality: Is it already part of the load forecast? Have all customers already paid for the benefits?
  - Reliability: What operational and contractual requirements do BTM resources have? How do they compare to traditional resources?
  - Fair compensation: Are existing structures, like rates, already creating an incentive for the behavior?

- **Load Forecasting**:
  - Reliability and incrementality: Demonstrating incremental impact is essential for reliability. Will moving into the RA program from the load forecast change the resources operating characteristics to increase reliability?

- **Visibility and Control:**
  - Interconnection: Are the resources studied in a way that reflects aggregated export?
  - Operation: Can the resources be safely integrated into the distribution network under different operating models? What additional communication and control systems would be needed to facilitate this safely and reliably?

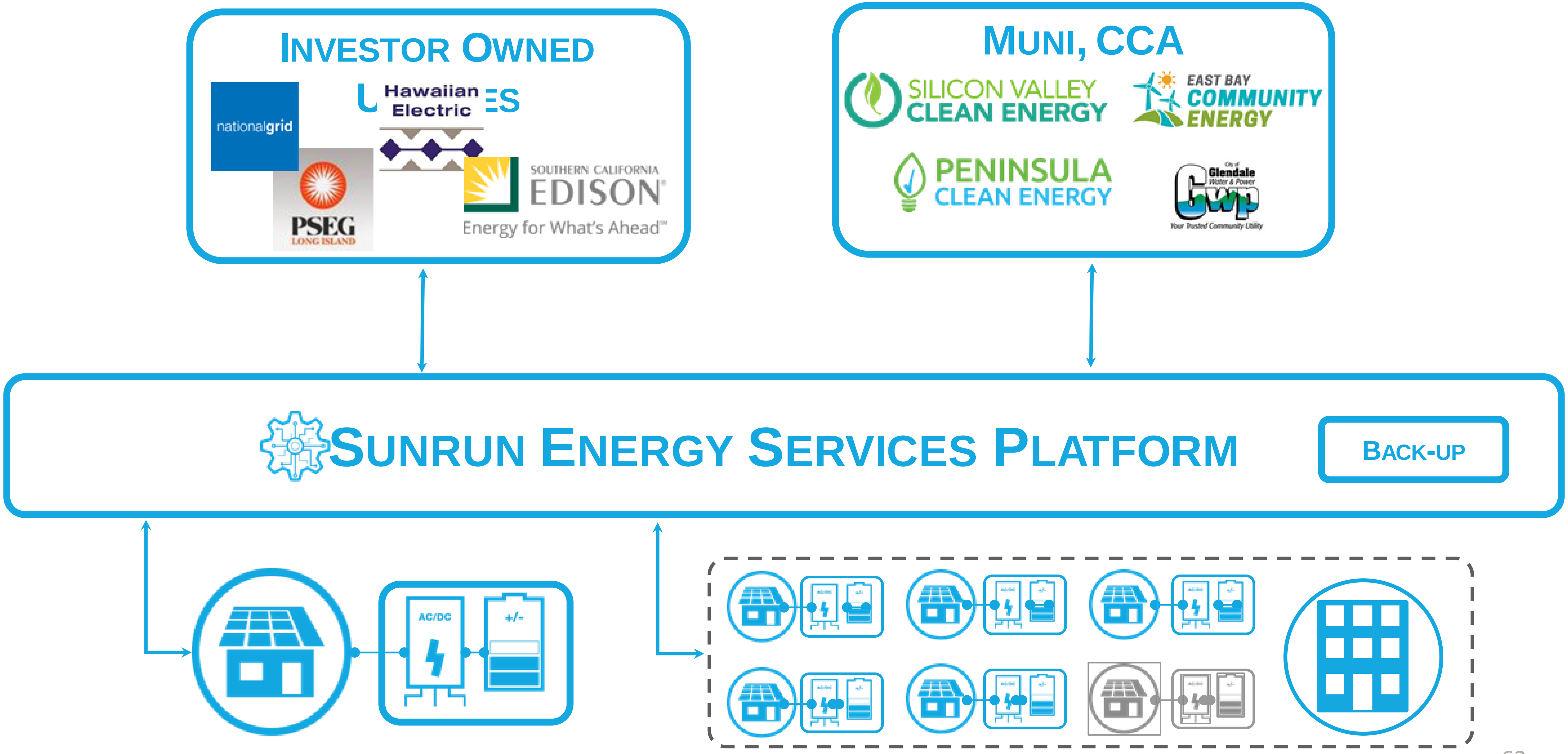
- **Customer Cost**:
  - Who pays?
  - Who benefits?

Behind the Meter Storage and Hybrid Resources

R.19-11-009

November 24, 2020 | RACHEL MCMAHON

Virtual Power Plants - Local, Dispatchable Capacity



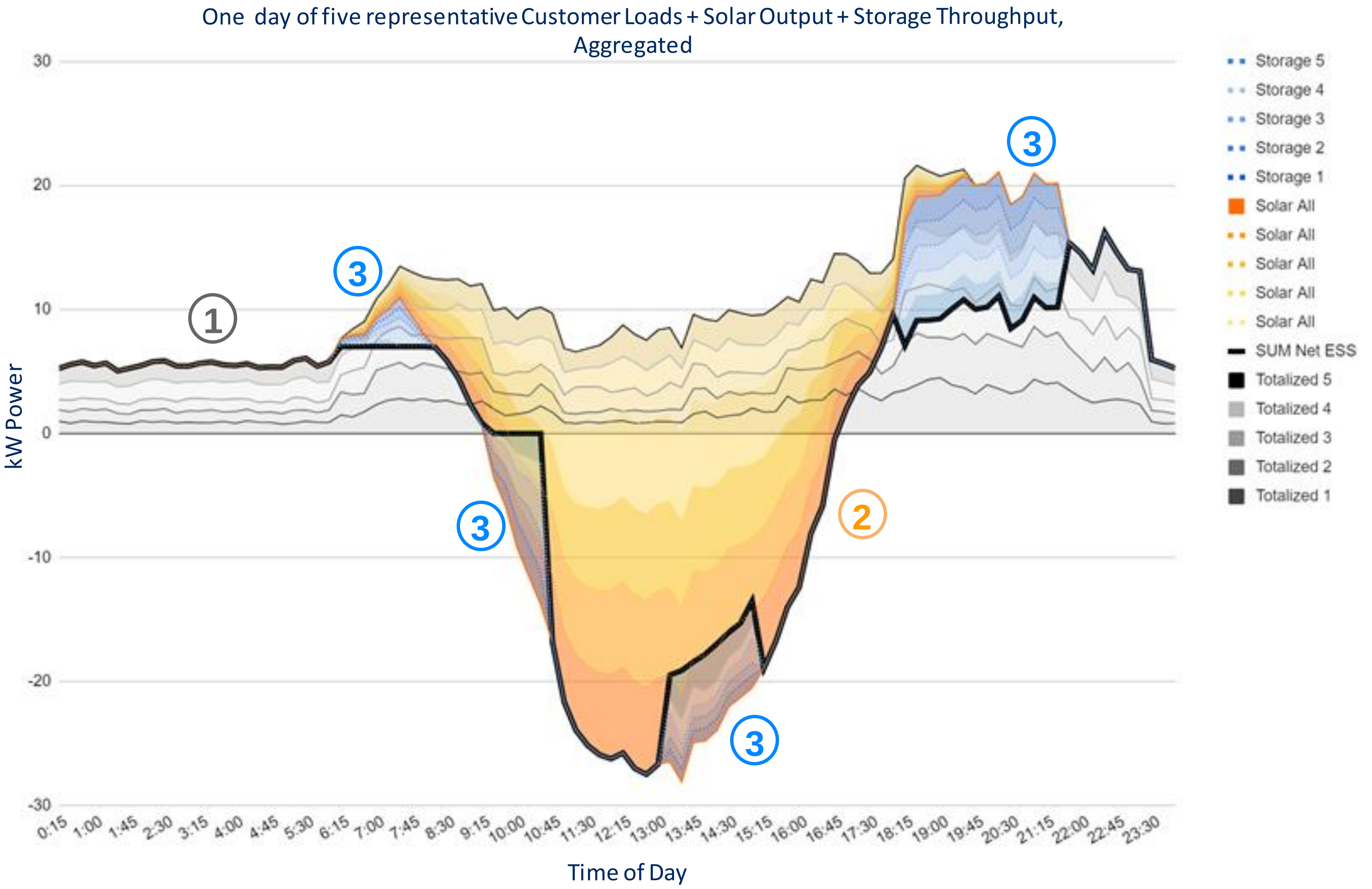
Virtual Power Plants

SOLAR PAIRED WITH FLEXIBLE STORAGE IS A GRID RESPONSIVE RESOURCE

1 Customer Native Load, when stacked, creates natural peaks in system demand that happen when electricity is typically used in the home.

2 Incremental solar depresses midday customer load, but tends to worsen ramping concerns on the grid, and the evening peaks still persist.

3 Distributed, aggregated energy storage can be charged and discharged to shape customer load to maximum benefit of both the grid and customers.



Issues in Decision 20-06-031

Forward determination of capacity associated with renewable production, consumption, charging, and export

- A forward determination associated with renewable production may not be necessary to establish QC value for BTM hybrid resources.
- Storage BTM resources - whether hybrid systems or standalone storage - should leverage the same QC methodologies of their equivalent IFM resources as a baseline.
- BTM energy storage resources are able to be directly submetered using an inverter, such direct measurement approaches should be utilized to the greatest extent possible.

RA requirements associated with customers providing capacity

- Customers provide capacity in the form of demand response, through LSE DR programs, DRAM, and LSE contracts (ie - SCE's solicitation to replace the capacity of the SONGs, and PG&E's solicitation to meet capacity shortfall in the South Bay-Moss Landing subarea).
- Any RA requirements would likely differ based on whether the BTM resource is integrated into the wholesale market.

Wholesale market participation including metering, dispatch control, and communication with CAISO

- BTM hybrids and storage should have option to either be 1) market integrated or 2) market informed and not integrated into the market, **but not both simultaneously.**
- For market integrated resources, the Scheduling Coordinator Metered Entity ("SCME") option is articulated in Sections 6.3.1 and 10.3 of the CAISO tariff, for *both* PDR and DERP resources.
- Telemetry requirements should not apply to these BTM resources, since they are based on single- resource size and not to the size of the aggregated resource.

Cost for energy associated with consumption, charging, and export

- In BTM hybrid systems, renewable generation and storage systems are integrated thus eliminating any need to consider the cost for energy associated with consumption and battery charging.
- BTM storage systems currently charge at retail, whether or not they directly participate in the CAISO market. Inability to differentiate the wholesale versus retail cost for charging and exporting energy has prevented BTM storage from participating in the NGR model as DERP-A resources. This issue could be addressed by developing an accounting mechanism.

sunrun

Changes such that net energy metering ("NEM") and self-generation incentive program ("SGIP") resources are compensated for capacity, while discounting for their NEM and SGIP compensation as necessary to ensure that the resources do not receive compensation beyond their value

- Obligations to provide capacity will not result in double compensation, as neither credits for NEM nor SGIP incentives convey resource adequacy capacity benefits, nor do these programs contain the same resource performance, testing, availability and dispatch obligations associated with provision of resource adequacy capacity.
- The Commission has thus far not established a universal incrementality framework for energy storage or hybrid resources.
- Precedent thus far: 1) Multiple use application framework adopted in D.18-01-033 allows for co-existence of customer domains services and incentives and services in other domains, including resource adequacy, without constraint; 2) incrementality framework recommended in staff proposals in both the the IDER proceeding as well as the microgrid docket, which affirm that all distribution level or resiliency services, respectively are additional to SGIP or NEM participation.

Load forecasting and adjustment for BTM resources

- Load adjustment process accounts for load migration and trues up DER adoption based on actual DER deployment on an ex post basis. Similar process could reduce LSE procurement obligations when LSEs procure BTM resources for resource adequacy. This adjustment process should be timed to enable reflection in year-ahead RA showings in October at a minimum, and also month ahead showings as feasible. This adjustment process may also simplify certain incrementality determinations.
- New BTM hybrid resources or storage resources should be treated as entirely new in the forecast.
- Embedded capacity value of energy storage as reflected in the load forecast may need more refinement, due to the dynamic nature of the resource and wide delta between expected SGIP-based deployment and actual deployment.
- Commission’s policy on multiple use applications for energy storage allows RA services to coexist simultaneously with customer-level services - some of which are reflected in forecast - without constraint.

Interaction of such resources with existing BTM resources such as proxy DR

- For market integrated resources, whether participating via PDR or DERP, recommend all of the following:
  - Allow PDR to export and eliminate any baselining on BTM storage output;
  - Amend Rule 21 to be usable for CAISO market integration;
  - Allow resources to settle on non-24/7 basis;
  - Determine and implement qualifying capacity methodology based on full resource output.

Deliverability determination

- Deliverability to the bulk system is likely unnecessary if the BTM system does not directly participate in the CAISO wholesale market.
- For market integrated resources, the current deliverability study and allocation process may need to be adapted to support streamlining and enable ability to deliver export capacity.
- On an interim basis, recommend exploring whether and how BTM energy storage currently interconnected as non-exporting could be enabled for exporting capability on an exceptional basis during emergencies, such as during the August heat storms.


Thank you.
sunrun

GRIDWORKS

COORDINATION OF TRANSMISSION AND DISTRIBUTION OPERATIONS IN A HIGH DISTRIBUTED ENERGY RESOURCE ELECTRIC GRID

GRIDWORKS

The Gridworks mission is to convene, educate and empower stakeholders to decarbonize the economy

Transmission and distribution grids are distinct systems

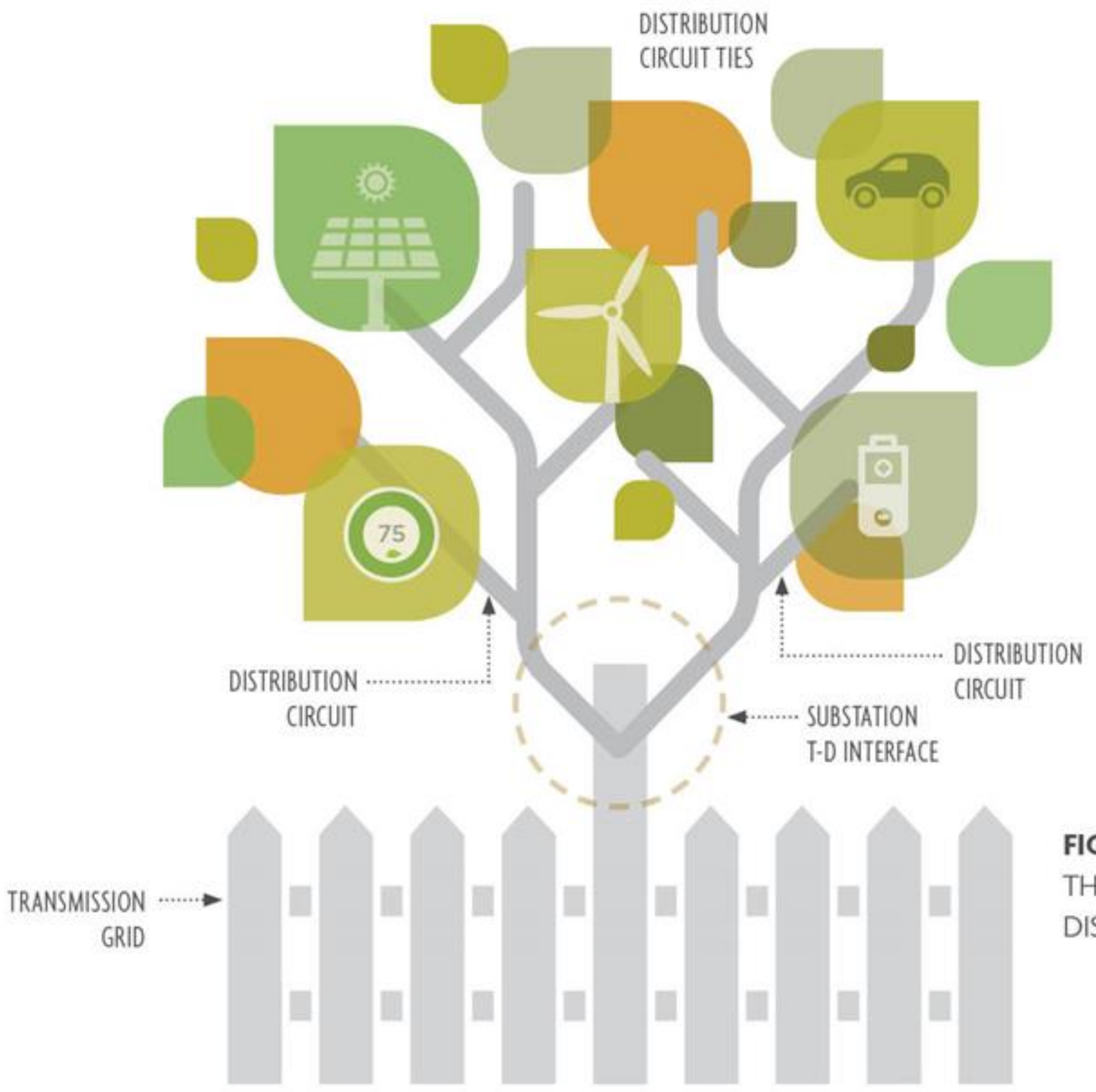


FIGURE 1. STRUCTURE OF THE TRANSMISSION AND DISTRIBUTION SYSTEMS

GRIDWORKS

Operational Challenges of DER

- Distribution systems' large and complex topology
- Frequency of distribution outages and use of switching configurations
- Forecasting the short-term effects of DERs on gross and net load
- Lack of visibility, situational awareness, and control
- DER effects on distribution system phase balancing and voltage regulation

To overcome, operators of the transmission and distribution systems, as well as DER providers, need to coordinate.

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Some key objectives of coordination

- Providing the ISO predictability of DER responses to dispatch instructions at the T-D interface
- Ensuring a Distribution Operator understands the current and predicted behavior of the DERs on its system to maintain reliability and safety
- Allowing a DER to participate in all markets for which it has the required performance and measurement capabilities, and to reasonably manage risk of potential curtailment

GRIDWORKS

Transmission - Distribution Coordination Today

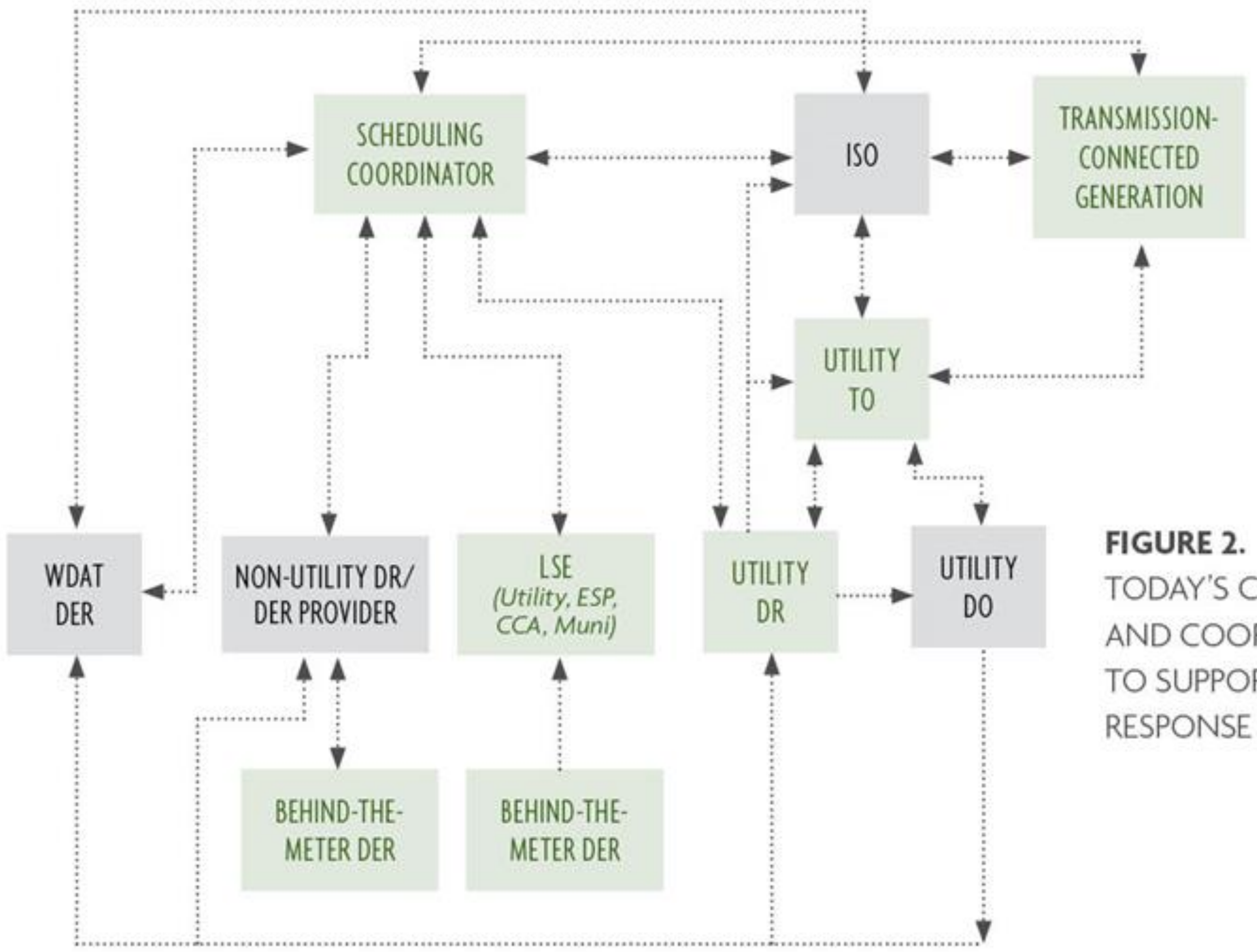

FIGURE 2.
TODAY'S COMMUNICATION AND COORDINATION LINKS TO SUPPORT DEMAND RESPONSE (DR)

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What information needs to be shared and with whom

FIGURE 3. NUMBERED DOTS INDICATE POSSIBLE COORDINATION ENHANCEMENTS FOR 2017 (NTE) AND FOR THE MEDIUM-LONG TERM (M/LTE) TO SUPPORT RELIABLE OPERATION WITH HIGH DER

INFORMATION TYPE	ISO	UTILITY TO	UTILITY DO	DERP
1 | DER/DERA bids into ISO market	✔		NTE 2	✔
2 | Installed capacity of each DER and DERA			✔	✔
3 | Total installed DER capacity per T-D substation			✔	
4 | Transmission topology and conditions	✔	✔		✔
5 | Distribution topology and conditions			✔	NTE 1
6 | DA forecasts of DER impacts	M/LTE 9	M/LTE 10	M/LTE 7	
7 | RT forecasts of DER impacts	M/LTE 9	M/LTE 10	M/LTE 8	
8 | DA schedules (results of ISO market)	✔	M/LTE 11	NTE 3	✔
9 | RT dispatches (results of ISO market)	✔	M/LTE 11	NTE 3	✔
10 | Transmission feasibility of schedules	Ensured by ISO market optimization			Ensured by ISO market optimization
11 | Distribution feasibility of schedules	NTE 6		NTE 4	NTE 5
12 | DER/DERA revenue meter data	(for participating DER/DERA)			✔
13 | Generation Telemetry (for real-time observation)	(>= 10 MW or providing AS)		(>= 1 MW)	✔
14 | T and D System Telemetry (for real-time observation)	T system (consistent across the system)	T system (consistent across the system)	D system (inconsistent)	

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Recommendations

- Distribution operators should pilot processes that communicate advisory information on system conditions
- The ISO should initiate processes that provide day-ahead schedules to the distribution operator
- The DER provider should communicate constraints on DER performance to the ISO
- The distribution utilities should assess a pro forma “integration agreement” with aggregated DERs

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Matthew Tisdale

mtisdale@gridworks.org

Stakeholders Panel

Panel Chair: Ed Randolph, Deputy Executive Director, CPUC Energy Division

Stefanie Tanenhaus, Principal Regulatory Analyst, East Bay Community Energy

Martin Wyspianski, Senior Director of Electric & Gas Acquisition, PG&E

Rachel McMahon, Senior Manager, Public Policy, SunRun

Matthew Tisdale, Executive Director, Gridworks

Stephen Castello, Regulatory Analyst, Electricity Pricing and Customer Programs, CalPA

2 – 3:45 p.m.

Principals Q&A

Public Q&A

Final Q&A and Public Comment

3:45 p.m. – 4:30 p.m.

California Public Utilities Commission

Thank you for attending BTM RA Valuation workshop.
Feedback welcome.

Hosts contact info:

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