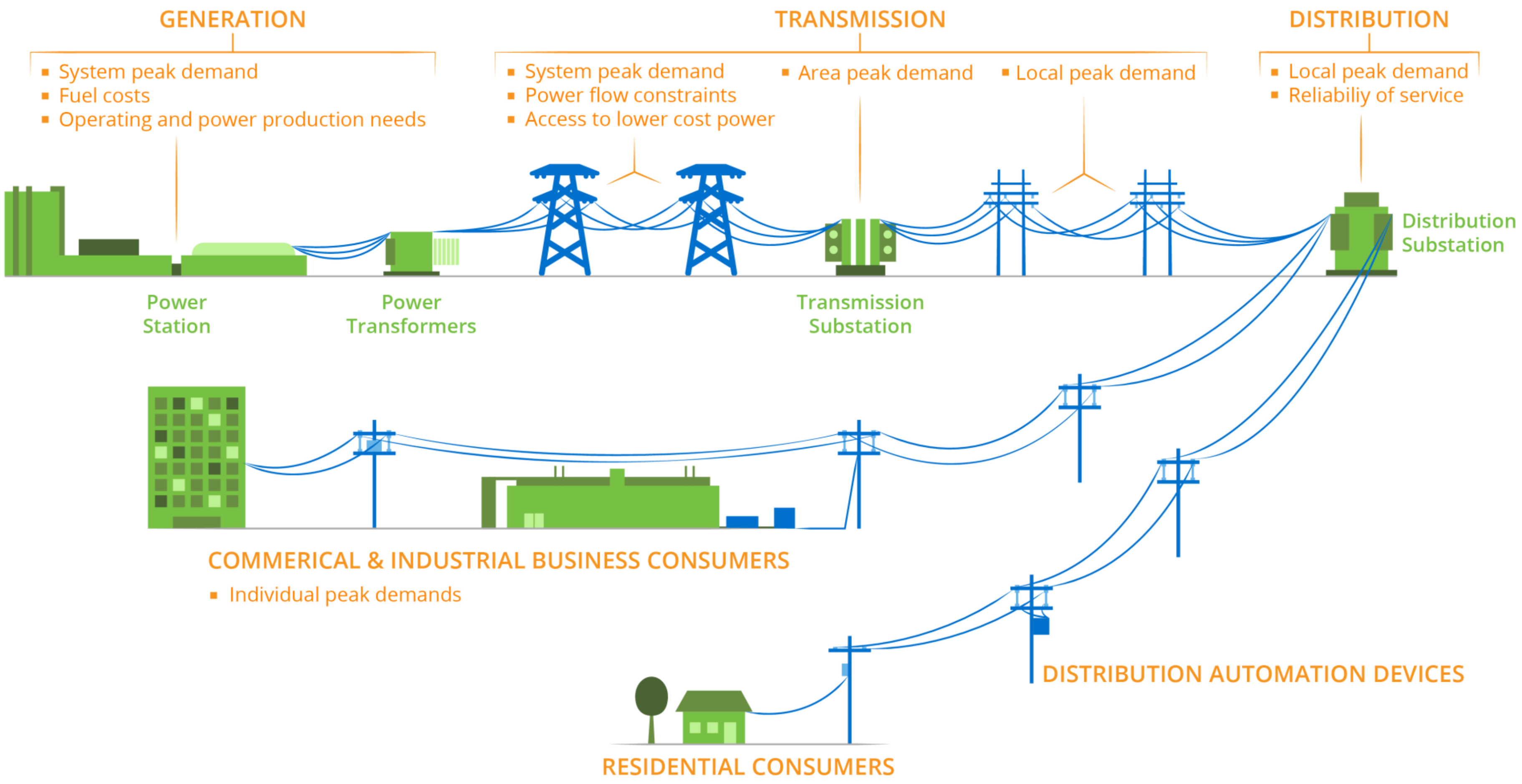
BEST PRACTICES FOR EVALUATING USE OF DISTRIBUTED ENERGY RESOURCES AS NON-WIRE ALTERNATIVES

Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

PUC PEER-SHARING WEBINARS ON INTEGRATED DISTRIBUTION SYSTEM PLANNING
HOSTED BY NARUC, BERKELEY LAB AND PACIFIC NORTHWEST NATIONAL LABORATORY
MAY 22, 2023

PEAK DEMAND AFFECTS PLANNING AT MULTIPLE LEVELS



One of the most unique attributes of DERs is that they can affect all aspects of the electric grid's infrastructure upstream of the customer, including investments in the central, or bulk, electricity system, and in distribution grids.

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DISTRIBUTED ENERGY RESOURCES INCLUDE A WIDE RANGE OF TECHNOLOGIES WITH DIVERSE OPERATING CHARACTERISTICS AND UNDERLYING LOADS

KEY QUESTION	CONSTRAINT	DEFINITION
Is the DER tied to a specific load shape?	Load profile	Structural shape of load reductions deliverable by a resource. For example, energy efficiency will deliver loads aligned with underlying consumption patterns (e.g., lighting or HVAC); solar PV will deliver loads varying by time of day, peaking in early afternoon; batteries of fuel based generation have no such limits.
	Seasonal availability	Availability year round versus summer only.
Is the resource flexible?	Availability window (start and end hours)	Hours of the day during which the resource is available. May be longer than the duration category. If duration category is shorter than the availability window, optimal window is used (e.g., the window with the most peak load).
	Ramp speed	Length of time it takes for resource to achieve maximum load reduction.
	Dispatch delay	Advance notice which must be given for resource to be dispatched.
Are there specific operating constraints?	Dispatch duration	Maximum number of consecutive hours during which a resource is able to deliver load reduction. May be limited by technology constraints (battery discharge time) or program limits (demand response event window).
	Max dispatch hours per year	Limit to total number of dispatchable hours in a year.
	Max events per year	Limit to total number of dispatch events (days) in a year.
	Max consecutive	Limit to total number of consecutive dispatch events (days) in a year.
	Events per year	(Days) in a year.

Source: Bode, Lemarchand and Schellenberg (2015). Addressing the Locational Valuation Challenge for Distributed Energy Resources. Available at: https://sepapower.org/resource/beyond-the-meter-addressing-the-locational-valuation-challenge-for-distributed-energy-resources/

KEY LESSONS

1. Provide enough lead time
2. Clearly define the need by hour and year (avoid blocks)
3. Require bidders to stack hourly resources and show they fulfill the need for each hour and year
4. Require use of standard end-use load shapes and transparent impact assumptions
5. Assess the net costs of the resource – what is the cost after you account for other benefits (besides deferral)?
6. View lump loads as an opportunity
7. Ensure you can measure the impacts
8. Use standardized inputs and contracts

#1 PROVIDE ENOUGH LEAD TIME

To avoid or defer distribution investments, incremental DER distribution capacity needs to be procured in advance. If they show up at the last minute, unannounced and unaccounted for, there may not be enough lead time to incorporate them into planning

Emergency Load Reductions (<2 years)

- Construction needs to happen quickly
- Often, there is insufficient time to build a DER portfolio large enough to defer investments

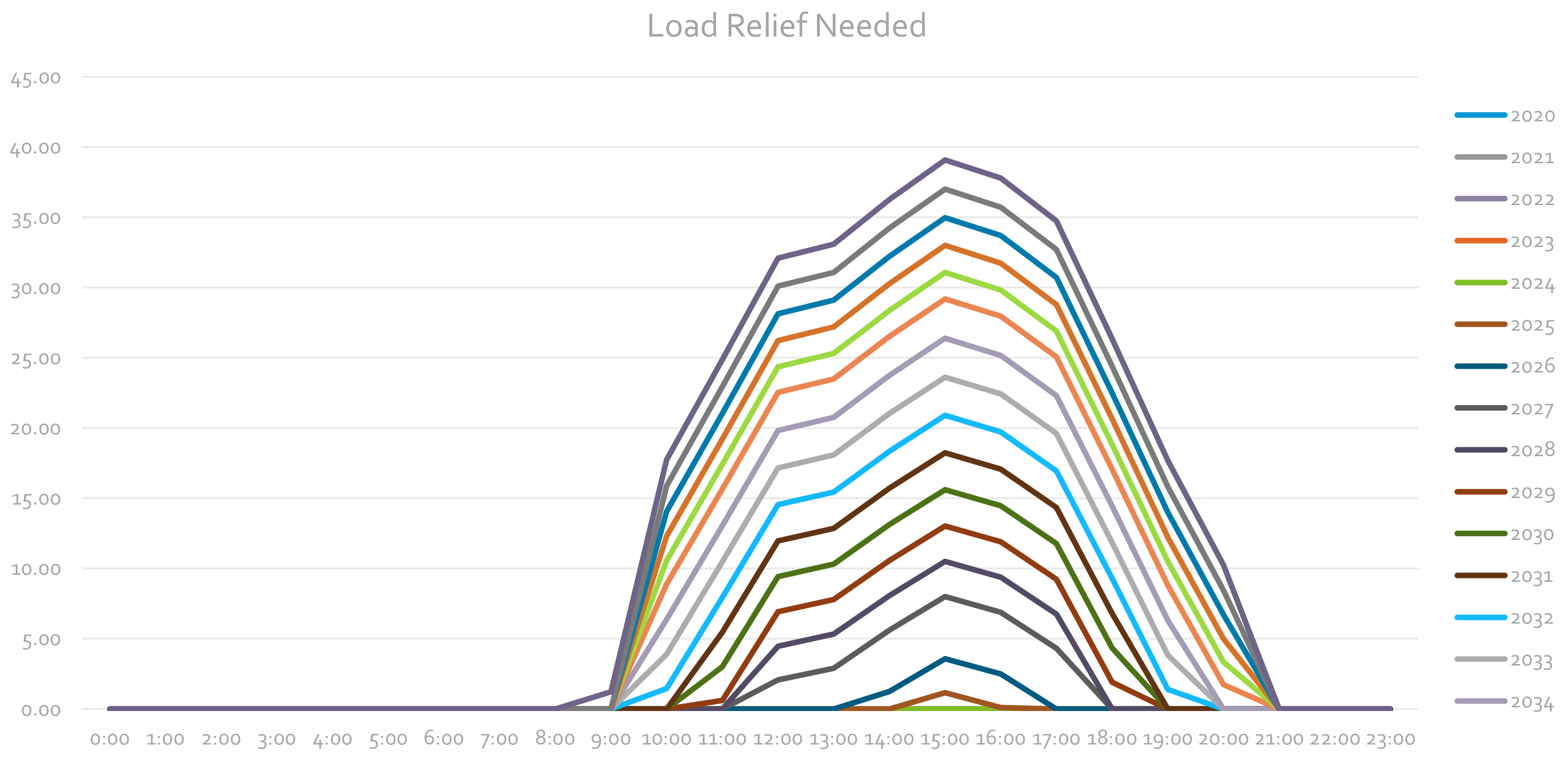
Contractual Obligations (3-6 years out)

- Specify the need and request DER bids
- Once resources are contracted, treat them as incremental capacity (but watch and reassess performance)
- Dispatchable resources can play a role

Incentivize permanent reductions and shifting (6+ years)

- Focus on bending the growth trajectory
- Focus on permanent shifting and resources with a long useful life such battery storage, solar, and energy efficiency

#2 CLEARLY DEFINE THE NEED BY HOUR AND YEAR (AVOID BLOCKS)



- The magnitude, timing, and duration of resources needed vary based on the forecast year
- Providing specific information allows bidders to craft DER portfolios to meet the needs
- Requiring blocks (e.g., 12-6 pm) is too blunt and can disqualify portfolios that meet the needs
- Clearly define frequency of resource needs by year

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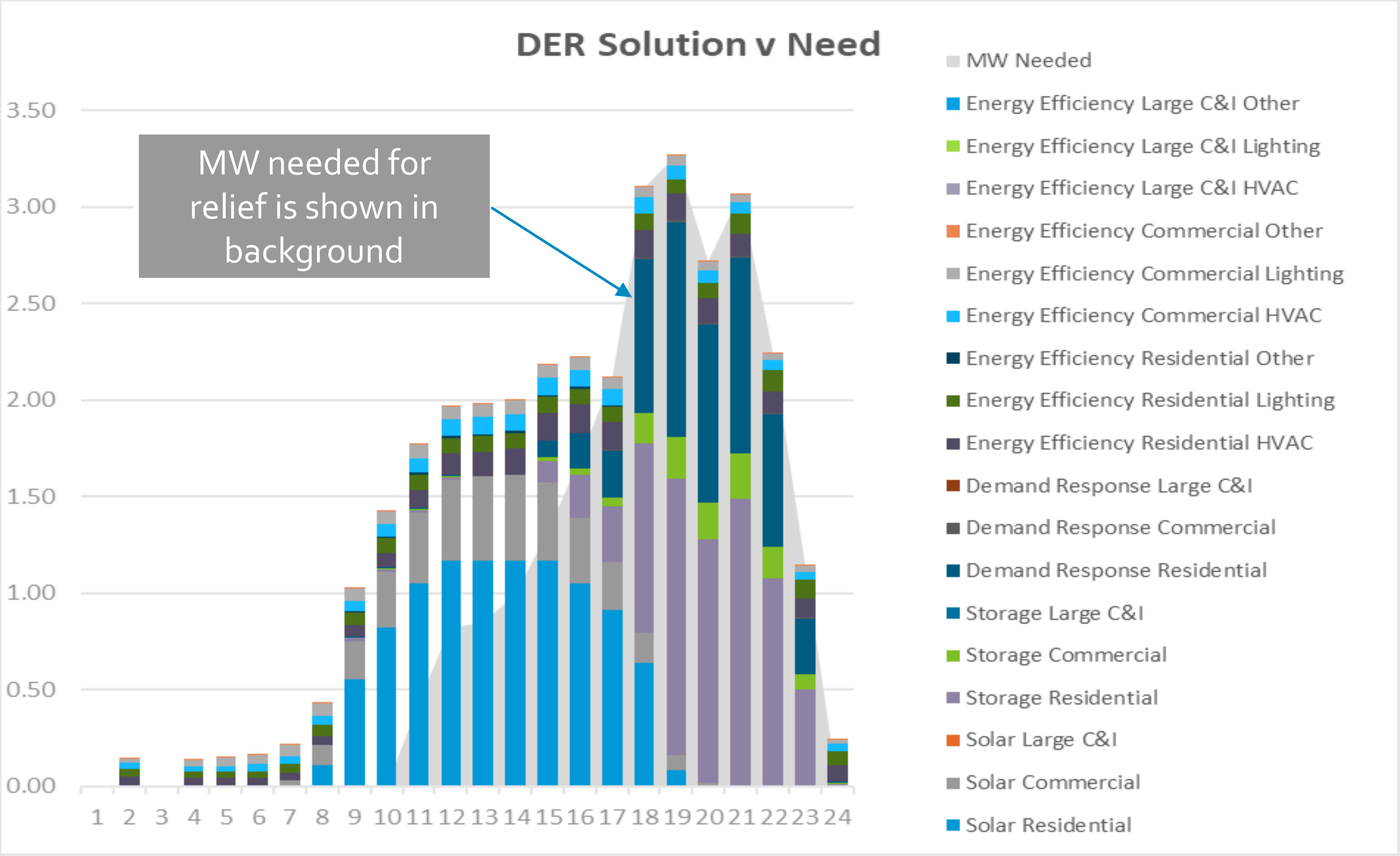
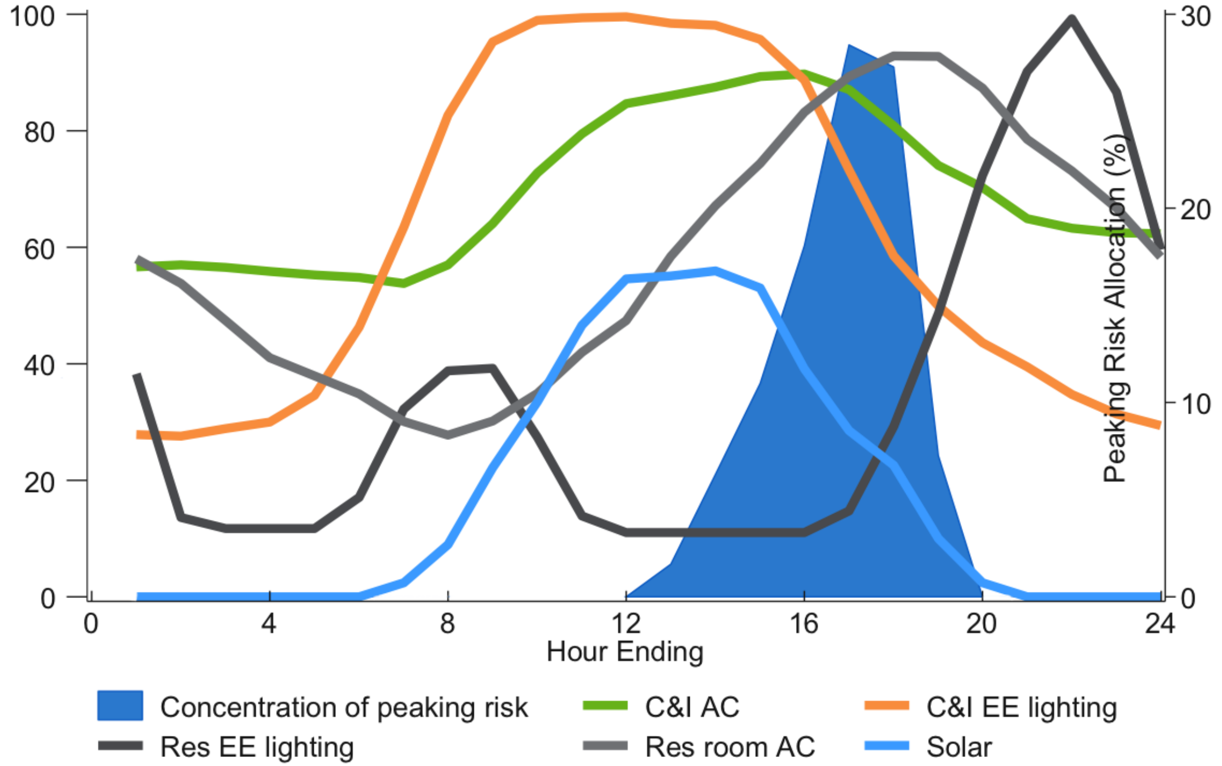
#3 REQUIRE BIDDERS TO STACK HOURLY RESOURCES AND SHOW THEY FULFILL THE NEED IN FULL



- Provide a bidder's template that requires the following for each resource:
  - Resource type (use a pick list)
  - Customer class
  - kW and kWh per customer
  - Hourly change in demand the resource will deliver by hour
  - # of times the resource can be dispatched per year
- The bidder template can stack those resources to show bidders how their resource performs against the need
- The approach ensures a clear definition of MWs, where they come from, and when they show up – and avoids crosstalk

#4 REQUIRE USE OF STANDARD END-USE LOAD SHAPES AND TRANSPARENT IMPACT ASSUMPTIONS



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- Bidders sometimes provide unrealistic timing and magnitude of resources
- Use published end-use load shapes (NREL/Berkeley Lab)
  - End-Use Load Profiles for the U.S. Building Stock go down to the county level
  - Practical Guidance on Accessing and Using the Data
- User can modify resource shapes – e.g., for battery storage – but should explain why and quantify the differences in shape from the standard
- Require users to cite source of demand reduction/impact estimates

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#5 ASSESS THE NET COSTS OF THE RESOURCE – WHAT IS THE COST AFTER YOU ACCOUNT FOR OTHER BENEFITS?

DER Type	Purchased kW (Nameplate)	Potential kW (Nameplate)	Max duration	Total Cost	Total Other Benefits	Costs per Nameplate kW	Other Benefits per Nameplate kW
Solar Residential	2,280	6,456	24	$1,512,346.24	$2,271,179.89	$663.23	$996.02
Solar Commercial	612	1,388	24	$615,014.14	$657,703.28	$1,004.90	$1,074.65
Solar Large C&I	100	208	24	$100,752.65	$103,292.29	$1,004.90	$1,030.23
Storage Residential	2,478	6,621	2	$4,212,634.05	$1,562,849.98	$1,700.00	$630.68
Storage Commercial	381	608	4	$648,067.74	$331,109.44	$1,700.00	$868.56
Storage Large C&I	0	0	24	$0.00	$0.00	$0.00	$0.00
Demand Response Residential	2,081	2,100	4	$2,651,485.46	$2,521,378.21	$1,273.91	$1,211.40
Demand Response Commercial	21	41	4	$16,272.57	$25,268.90	$771.50	$1,198.03
Demand Response Large C&I	16	31	4	$8,062.69	$54,093.16	$513.11	$3,442.51
Energy Efficiency Residential HVAC	148	311	24	$1,081,245.40	$214,825.71	$7,283.74	$1,447.16
Energy Efficiency Residential Lighting	112	188	24	$19,326.99	$249,293.80	$172.39	$2,223.61
Energy Efficiency Residential Other	10	21	24	$92,560.19	$14,862.21	$9,031.82	$1,450.22
Energy Efficiency Commercial HVAC	91	186	24	$550,086.30	$122,261.28	$6,048.43	$1,344.31
Energy Efficiency Commercial Lighting	70	127	24	$15,477.68	$158,597.43	$221.32	$2,267.86
Energy Efficiency Commercial Other	2	4	24	$8,992.94	$4,910.08	$5,043.70	$2,753.83
Energy Efficiency Large C&I HVAC	0	0	24	$0.00	$0.00	$0.00	$0.00
Energy Efficiency Large C&I Lighting	0	0	24	$0.00	$0.00	$0.00	$0.00
Energy Efficiency Large C&I Other	0	0	24	$0.00	$0.00	$0.00	$0.00
Marketing Acquisition Costs	0	$0.00		$951,107.72			
TOTAL	8,403	18,290		$12,483,432.75	$8,291,625.66		

- DERs often provide other benefits
- What is the net cost after accounting for other benefits (excluding T&D)?
- Is the net cost lower than the deferral value?
- Key pitfalls
  - Not including the other benefits
  - Excluding real benefits that are not in the deferral contract
  - Only including hours in the deferral contract

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#6 VIEW LUMP LOADS AS AN OPPORTUNITY

WHAT ARE LUMP LOADS?

- They are large new loads for facilities that are being built (e.g., large distribution warehouse)
- Developer provides a spec of max loads per circuit
- It's hard to forecast when and where they pop up and how much actual load shows up

WHY DO THEY MATTER?

- A substantial number of distribution upgrades are driven by lump loads
- Shorter timelines – it is often not possible to go through an RFP process
- Asymmetric – planners pay a lot of attention to new lump loads, less so to lump loads that retire

WHAT CAN BE DONE?

- Add solar, storage, energy efficiency, and demand response at the site to limit loads they are in the process of building
- Ensure they use these technologies to limit maximum demand or that they follow a load shape that reduces impacts on the substation or circuit peak demand
- Allow utilities to bypass a lengthy RFP process to address lump load additions at the site

Forecast Loads

	Weather Year Conditions and assetid					
	1in10			1in2		
year	MY_5072	Maybrook	Montgomery	MY_5072	Maybrook	Montgomery
2021	1.32	20.94	7.90	1.23	19.38	6.90
2022	1.38	21.53	8.28	1.28	19.93	7.23
2023	1.44	22.14	8.67	1.34	20.49	7.57
2024	1.50	22.76	9.08	1.40	21.06	7.93
2025	1.56	23.40	9.51	1.46	21.65	8.31
2026	1.63	24.05	9.97	1.52	22.26	8.70
2027	1.71	24.73	10.44	1.59	22.89	9.12
2028	1.78	25.42	10.94	1.66	23.53	9.55
2029	1.86	26.14	11.45	1.74	24.19	10.00
2030	1.94	26.87	12.00	1.81	24.87	10.48
2031	2.03	27.63	12.57	1.89	25.57	10.98
2032	2.11	28.40	13.17	1.97	26.29	11.50

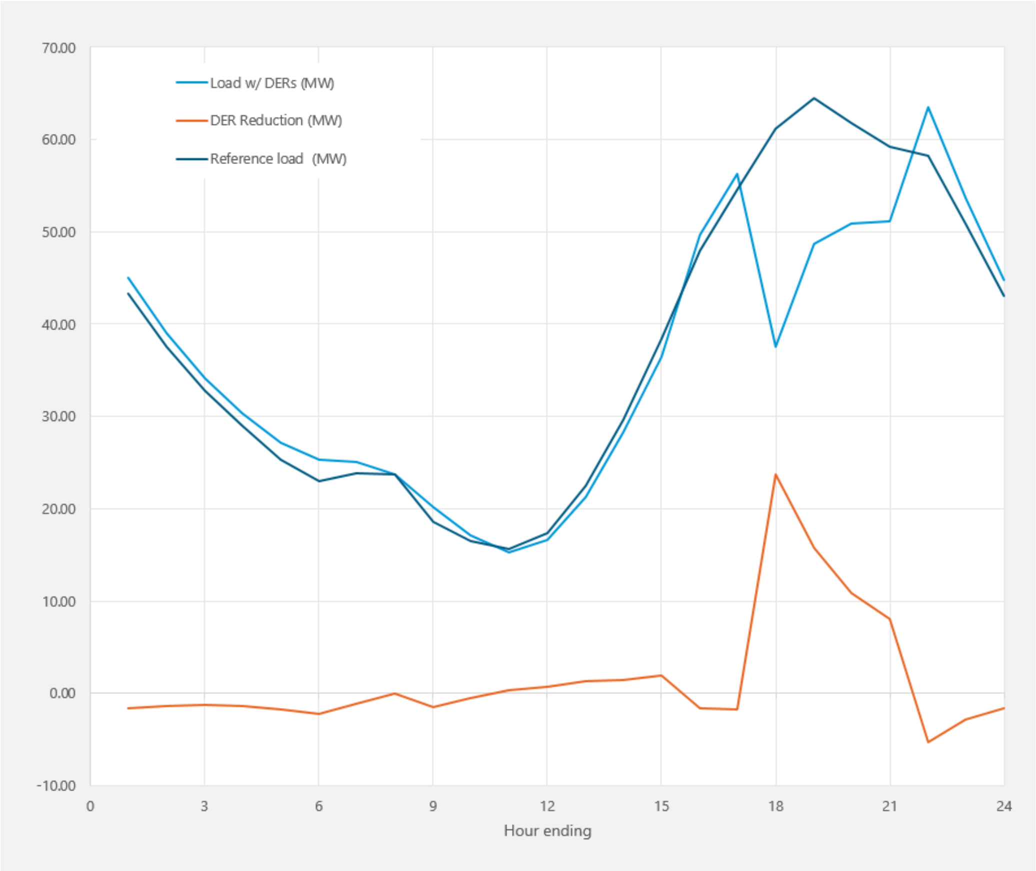
+ Coincident Lump Loads

	Weather Year Conditions and assetid					
	1in10			1in2		
year	MY_5072	Maybrook	Montgomery	MY_5072	Maybrook	Montgomery
2021	1.42	0.00	1.42	1.84	0.00	4.71
2022	5.21	0.00	8.50	4.82	0.00	7.97
2023	5.21	0.00	8.50	4.82	0.00	7.97
2024	5.21	0.00	8.50	4.82	0.00	7.97
2025	5.21	0.00	8.50	4.82	0.00	7.97
2026	5.21	0.00	8.50	4.82	0.00	7.74
2027	5.21	0.00	8.50	4.82	0.00	7.74
2028	5.21	0.00	8.50	4.82	0.00	7.74
2029	5.21	0.00	8.50	4.82	0.00	7.74
2030	5.21	0.00	8.50	4.82	0.00	7.74
2031	5.21	0.00	8.50	4.82	0.00	7.74
2032	5.16	0.00	8.50	4.82	0.00	7.74

= Loading

	Weather Year Conditions and assetid					
	1in10			1in2		
year	MY_5072	Maybrook	Montgomery	MY_5072	Maybrook	Montgomery
2021	2.73	20.94	9.32	2.77	19.38	10.27
2022	6.52	21.53	16.78	6.06	19.93	15.01
2023	6.57	22.14	17.17	6.12	20.49	15.34
2024	6.63	22.76	17.59	6.17	21.06	15.69
2025	6.70	23.40	18.02	6.23	21.65	16.06
2026	6.76	24.05	18.47	6.30	22.26	16.45
2027	6.83	24.73	18.94	6.36	22.89	16.86
2028	6.90	25.42	19.44	6.43	23.53	17.29
2029	6.97	26.14	19.96	6.50	24.19	17.75
2030	7.05	26.87	20.50	6.57	24.87	18.22
2031	7.13	27.63	21.07	6.65	25.57	18.72
2032	7.22	28.40	21.67	6.73	26.29	19.24

#7 ENSURE YOU CAN MEASURE THE IMPACTS



Hour ending	Reference load (MW)	Load w/ DERs (MW)	DER Reduction (MW)	Total Reduction
1	43.32	45.00	-1.68	-1.68
2	37.59	39.00	-1.41	-1.41
3	32.80	34.09	-1.29	-1.29
4	28.92	30.29	-1.37	-1.37
5	25.35	27.16	-1.81	-1.81
6	23.03	25.28	-2.25	-2.25
7	23.88	25.07	-1.19	-1.19
8	23.67	23.74	-0.07	-0.07
9	18.63	20.12	-1.49	-1.49
10	16.52	17.10	-0.58	-0.58
11	15.66	15.31	0.35	0.35
12	17.39	16.65	0.74	0.74
13	22.53	21.25	1.27	1.27
14	29.57	28.19	1.37	1.37
15	38.36	36.45	1.91	1.91
16	47.95	49.63	-1.67	-1.67
17	54.60	56.30	-1.69	-1.69
18	61.21	37.54	23.67	23.67
19	64.44	48.68	15.75	15.75
20	61.74	50.92	10.82	10.82
21	59.23	51.20	8.03	8.03
22	58.21	63.49	-5.28	-5.28
23	50.87	53.74	-2.87	-2.87
24	43.07	44.76	-1.69	-1.69
Daily	**Reference load (MWh)**	**Estimated load w/ DR (MWh)**	**DR Energy savings (MWh)**	**Total Energy savings (MWh)**
Daily kWh	898.53	860.95	37.58	37.58

- Have an evaluation plan that leaves no ambiguity
- Test the full resource potential early, over the hours required
- Is the resource delivering the magnitude of load relief required?
- Is the resource meeting the shape requirements?
- Beware of custom baselines and asymmetry
- Assess impacts using hourly data
  - Advanced metering infrastructure
  - End-use data
  - SCADA data

#8 USE STANDARDIZED INPUTS & CONTRACTS

Measure Type	Residential - Room AC control	Measure Type	Residential - Lighting	Measure Type	Residential - Solar	Measure Type	Commercial - Solar	Measure Type	Residential - Pool pump switches	Measure Type
Customer Type	Residential	Customer Type	Residential	Customer Type	Residential	Customer Type	Commercial (Small)	Customer Type	Residential	Customer Type
KW/customer	4.00	KW/customer	0.80	KW/customer	3.58	KW/customer	74.00	KW/customer	0.30	KW/customer
KWh/customer		KWh/customer		KWh/customer	8585.00	KWh/customer	125093.00	KWh/customer		KWh/customer
Measure Useful Life (Calculated)	10		20		20		20		10	
Measure Useful Life (Please Enter Manually if Different than										

Resource Profile (kW)		Resource Profile (kW)		Resource Profile (kW)		Resource Profile (kW)		Resource Profile (kW)		Resource Profile
0:00	1.68	0:00	0.00	0:00	0.00	0:00	0.00	0:00	0.01	0:00
1:00	1.51	1:00	0.27	1:00	0.00	1:00	0.00	1:00	0.01	1:00
2:00	1.36	2:00	0.00	2:00	0.00	2:00	0.00	2:00	0.01	2:00
3:00	1.22	3:00	0.23	3:00	0.00	3:00	0.00	3:00	0.01	3:00
4:00	1.18	4:00	0.24	4:00	0.00	4:00	0.03	4:00	0.01	4:00
5:00	1.11	5:00	0.26	5:00	0.00	5:00	0.65	5:00	0.01	5:00
6:00	1.00	6:00	0.31	6:00	0.00	6:00	5.50	6:00	0.02	6:00
7:00	1.14	7:00	0.40	7:00	0.34	7:00	17.43	7:00	0.03	7:00
8:00	1.45	8:00	0.50	8:00	1.70	8:00	33.33	8:00	0.08	8:00
9:00	1.98	9:00	0.55	9:00	2.52	9:00	48.53	9:00	0.17	9:00
10:00	2.59	10:00	0.57	10:00	3.23	10:00	60.97	10:00	0.24	10:00
11:00	3.08	11:00	0.56	11:00	3.58	11:00	70.05	11:00	0.28	11:00
12:00	3.49	12:00	0.57	12:00	3.58	12:00	73.33	12:00	0.29	12:00
13:00	3.74	13:00	0.57	13:00	3.58	13:00	74.04	13:00	0.29	13:00
14:00	3.91	14:00	0.58	14:00	3.58	14:00	67.96	14:00	0.27	14:00
15:00	4.02	15:00	0.59	15:00	3.23	15:00	56.20	15:00	0.24	15:00
16:00	3.81	16:00	0.57	16:00	2.80	16:00	41.57	16:00	0.17	16:00
17:00	3.69	17:00	0.57	17:00	1.97	17:00	25.77	17:00	0.13	17:00
18:00	3.48	18:00	0.50	18:00	0.26	18:00	12.79	18:00	0.08	18:00
19:00	3.29	19:00	0.55	19:00	0.00	19:00	2.70	19:00	0.04	19:00
20:00	3.05	20:00	0.71	20:00	0.00	20:00	0.01	20:00	0.02	20:00
21:00	2.81	21:00	0.80	21:00	0.00	21:00	0.00	21:00	0.02	21:00
22:00	2.63	22:00	0.70	22:00	0.00	22:00	0.00	22:00	0.02	22:00
23:00	2.47	23:00	0.50	23:00	0.00	23:00	0.00	23:00	0.01	23:00

Provide a brief description of Measure | Provide a brief description of Measure | Provide a brief description of Measure | Provide a brief description of Measure | Provide a brief description of Measure | Provide a brief descrip

Number of Customers (by year)		Number of Customers (by year)		Number of Customers (by year)		Number of Customers (by year)		Number of Customers (by year)		Number of Custor
2022	8.4	2022	45.65	2022	19.4	2022	2.45	2022	2.1	2022
2023	8.4	2023	45.65	2023	19.4	2023	2.45	2023	2.1	2023
2024	8.4	2024	45.65	2024	19.4	2024	2.45	2024	2.1	2024
2025	8.4	2025	45.65	2025	19.4	2025	2.45	2025	2.1	2025
2026	8.4	2026	45.65	2026	19.4	2026	2.45	2026	2.1	2026
2027	8.4	2027	45.65	2027	19.4	2027	2.45	2027	2.1	2027
2028	8.4	2028	45.65	2028	19.4	2028	2.45	2028	2.1	2028
2029	8.4	2029	45.65	2029	19.4	2029	2.45	2029	2.1	2029
2030	8.4	2030	45.65	2030	19.4	2030	2.45	2030	2.1	2030
2031	8.4	2031	45.65	2031	19.4	2031	2.45	2031	2.1	2031
2032	8.4	2032	45.65	2032	19.4	2032	2.45	2032	2.1	2032
2033	8.4	2033	45.65	2033	19.4	2033	2.45	2033	2.1	2033
2034	8.4	2034	45.65	2034	19.4	2034	2.45	2034	2.1	2034
2035	8.4	2035	45.65	2035	19.4	2035	2.45	2035	2.1	2035
2036	8.4	2036	45.65	2036	19.4	2036	2.45	2036	2.1	2036
2037	8.4	2037	45.65	2037	19.4	2037	2.45	2037	2.1	2037
2038	8.4	2038	45.65	2038	19.4	2038	2.45	2038	2.1	2038
2039	8.4	2039	45.65	2039	19.4	2039	2.45	2039	2.1	2039
2040	8.4	2040	45.65	2040	19.4	2040	2.45	2040	2.1	2040
2041	8.4	2041	45.65	2041	19.4	2041	2.45	2041	2.1	2041
2042	8.4	2042	45.65	2042	19.4	2042	2.45	2042	2.1	2042

Instructions | Bidder Information | Measure Capacity & Profile | Price Information | Price Breakdown (Informational) | PSEC

Drop down menus with pick lists

Resources delivered by hour

Magnitude of resources over time

Stand pricing templates and clear definition of resource needs

- If you don't use standardized inputs, you'll end up with more work and ambiguity.
  - For example, what does a MW of a resource mean?
- Ensure stackability of resources
- Allow comparison of multiple bids
- Reduce effort for bidders and reviewers

KEY LESSONS RECAP

1. Provide enough lead time
2. Clearly define the need by hour and year (avoid blocks)
3. Require bidders to stack hourly resources and show they fulfill the need for each hour and year
4. Require use of standard end-use load shapes and transparent impact assumptions
5. Assess the net costs of the resource – what is the cost after you account for other benefits (besides deferral)?
6. View lump loads as an opportunity
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QUESTIONS?

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NWA In Colorado

Megan Gilman, Commissioner

The views expressed in this presentation are those of the presenter and do not necessarily reflect the views of the Colorado Public Utilities Commission or any other individual Commissioner.

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Department of Regulatory Agencies
Public Utilities Commission

SB19-236 DSP Legislation

Must do the following regarding non-wires alternatives (NWAs):

- Define NWAs
- Develop methodology for evaluating costs and benefits of using DERs as NWAs
- Determine threshold for size of new distribution project when utility must consider NWAs
- Direct each qualifying utility to file a DSP with additional system information
- Include NWA analysis to provide new electric service to any planned developments expected to include ≥ 10,000 new residences

Rulemaking 20R-0516E

Concluded December 2020

Establish base criteria for electric utility Distribution System Plans, including NWA analysis and solicitations

Rulemaking 20R-0516E

Commissioner Megan Gilman

- **Rule 3532 Grid Needs Assessment** – Includes analysis regarding suitability of NWA to mitigate identified needs and recommendations for the deployment of utility infrastructure upgrade solutions versus the procurement of NWA to address any identified needs.
- **Rule 3533 Grid Innovation** – Identification of any barriers to deployment of DERs and NWA.

Rulemaking 20R-0516E

Commissioner Megan Gilman

- **Rule 3535 NWA Cost Benefit Analysis** – Develop and publish a CBA methodology. CBA should consider approach from National Standard Practice Manual.
- **Rule 3536 Action Plan** – Action plan for implementation of NWAs to address grid needs not classified as major distribustion system projects, costs and plans associated with obtaining data necessary for evaluation of NWAs.
- Updated Phase II action plan with sequence, timeline, interaction for NWAs identified in solicitation process.

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Rulemaking 20R-0516E

Commissioner Megan Gilman

- **Rule 3537 NWA Solicitation Process (Phase II)** – Phase II and bidding process required for any major projects. DSP application includes timelines for Phase II. Concept is an expedited, comment-based Phase II to facilitate timely decisions and implementation of NWA bids.
- Use of independent evaluator (IE) for major grid projects
- Utility selects NWA bidder to advance to Phase II -> within 30 days IE must file report.

COLORADO
Department of Regulatory Agencies
Public Utilities Commission

Rulemaking 20R-0516E

Commissioner Megan Gilman

- **Rule 3538 Approvals and Cost Recovery** – Commission shall approve utility's NWA investments if investment is in public interest.

PSCO First DSP 22A-0189E

Commissioner Megan Gilman

- May 2, 2022 - Public Service Company of Colorado filed first Distribution System Plan
- Unopposed Non-Comprehensive Settlement Agreement
- Advanced several projects to Phase II, but excluded projects involving service to Critical Infrastructure customers, as defined by the Company.

PSCO First DSP 22A-0189E

Commissioner Megan Gilman

- Phase II Ongoing – Commission has not yet seen bids or results from Phase II.
- Per settlement, Company will include information for all bids received and detailed CBA for all bids. Phase II report will include proposal for what, if any, NWA selected with rationale for chosen bids or for situations where no NWA are proposed.
- Agreement will use deferral and contract period for full length of forecasted grid need based on 10 year forecast.

PSCO First DSP 22A-0189E

Commissioner Megan Gilman

- Settling parties agreed to 25% safety margin for NWA, but committed to reevaluating safety margins for future DSPs.
- In next DSP, Company committed to providing full magnitude, duration and frequency of load relief requirements for any proposed candidate NWA project.

NON-WIRES ALTERNATIVES

CANDIDATE DEFERRAL OPPORTUNITIES IN UTILITY DISTRIBUTION PLANNING PROCESSES

Presented at NARUC Webinar | May 22, 2023

Rob Peterson, CPUC, Energy Division

Agenda

1. Candidate Deferral Opportunities (Non-Wires Alternatives)
2. Distribution Investment Deferral Framework (DIDF) Process
3. Grid Needs Assessment / Distribution Deferral Opportunity Reports (GNA/DDORs)
4. 2023/2024 DIDF Cycle (the current DIDF cycle)
5. Utility Distribution Planning Processes (DPPs) and DIDF
6. Key Takeaways

Additional Slides

A. DER Procurement Types for the DIDF

B. Utility GNA/DDOR Filing Excerpts

C. Online Resources

Utilities = Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric

Acronym Guide

- DER: Distributed Energy Resource
  - BTM: Behind-the-Meter DER
  - FTM: Front-of-the-Meter DER
- DPP: Distribution Planning Process, run by investor-owned utilities
- DIDF: Distribution Investment Deferral Framework (regulatory and oversight process)
- GNA/DDOR: Grid Needs Assessment/Distribution Deferral Opportunities Report filings present DPP outcomes annually

Non-Wires Alternatives Selection Process

- *Non-Wires Alternative = Candidate Deferral Opportunity*

1. Demand forecast disaggregated from system level to distribution circuit level
2. Distribution grid needs identified
3. Mitigations/solutions to grid needs identified
4. Planned investments identified (traditional investments)
5. Utility filings
6. Planned investments ranked according to DER deferral potential
7. **Candidate deferral opportunities** selected (DER/non-wires investments)
8. DER procurements launched
9. If successful, contracts executed
10. If not successful, the traditional planned investment is built instead (contingency plan)
11. Review and reform process for the next cycle

Distribution Investment Deferral Framework (DIDF) Overview

Load and DER Growth Forecasting
Utility disaggregates to circuit level the IEPR* demand and DER forecasts

→

Grid Needs Assessment (GNA)
Utility identifies distribution system deficiencies to determine grid needs

→

Distribution Deferral Opportunities Report (DDOR)
Utility identifies planned investments *[then]* Identifies and ranks deferral opportunities

→

Distribution Planning Advisory Group
A semi-formal stakeholder working group reviews the utility GNA/DDOR filings

→

Procurement

- Request for Offers (Front-of-the-Meter DERs)
- Standard Offer Contract (Front-of-the-Meter DERs) *1st Launch in Sept. 2021*
- DER Deferral Tariff "Partnership Pilot" (Behind-the-Meter DERs) *1st Launch in Jan. 2022*

→

Reform
Ongoing improvement and innovation through annual process updates.

*The California Energy Commission prepares the top-down demand forecast published in the Integrated Energy Policy Report (IEPR). The same top-down demand forecast is used as the basis for the CPUC's Integrated Resources Plan process and California Independent System Operator's Transmission Planning Process.

Grid Needs Assessment & Distribution Deferral Opportunities Report (GNA/DDOR)

GNA
Load and DER forecast for all circuits and transformers
List of all forecasted system deficiencies

Load Transfers Applied
Multiple Grid Needs Per Project

DDOR: Planned Investments
List of traditional ("wired") infrastructure upgrades (planned investments) and costs

General Rate Case

Technical and Timing Screens

DDOR: Candidate Deferrals List and Ranking (Tiers 1 to 3)

Prioritization Metrics
Distribution Planning Advisory Group Feedback and Independent Professional Engineer (IPE) Reports

DDOR: Final Candidate Deferral List

Competitive Solicitations
Independent Evaluator (IE) Reports

<u>Status</u>:

DIDF Adopted in D.18-02-004

Implemented first cycle in 2018

DIDF Today

- We are in the 2023/2024 DIDF Cycle (2023 GNA/DDOR filings due August 15th)
- We are receiving comments today (5/22/2023) from stakeholders about how to improve utility DPPs and GNA/DDOR filings as we prepare the grid for electrification (see March and April 2023 Rulings here with questions to stakeholders)
- We are currently considering the California Energy Commission demand forecast dataset to apply to the next 2024 GNA/DDOR filings (2024/2025 DIDF Cycle); see dataset options at Table 2, p. 46, here.

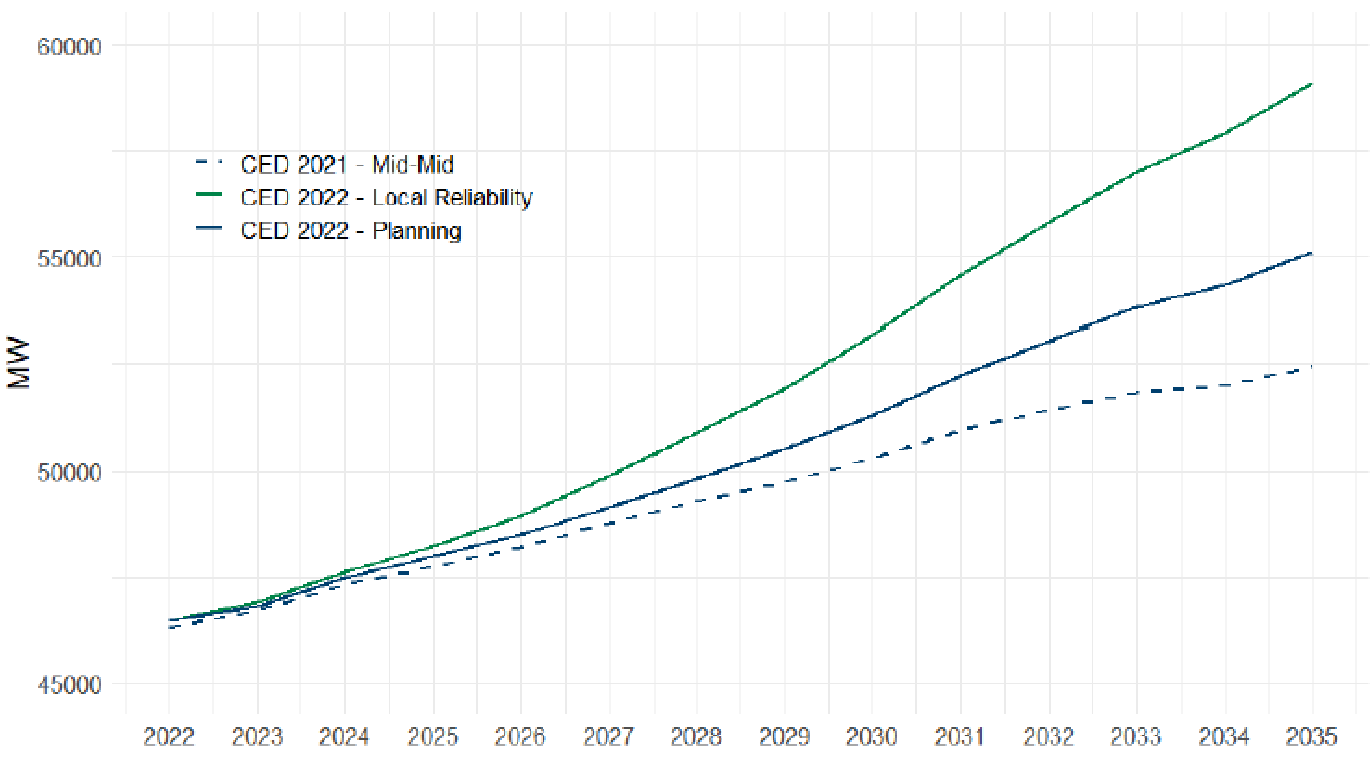
California Energy Commission 2022 Demand Forecast Datasets (Adopted Spring 2023)

*The Local Reliability Scenario is expected to be used for distribution planning and the 2024/2025 DIDF Cycle. The official "demand forecast" dataset is labeled "Planning Forecast" in the following table.

Table 2: Revised Forecast and Additional Achievable Scenario Framework

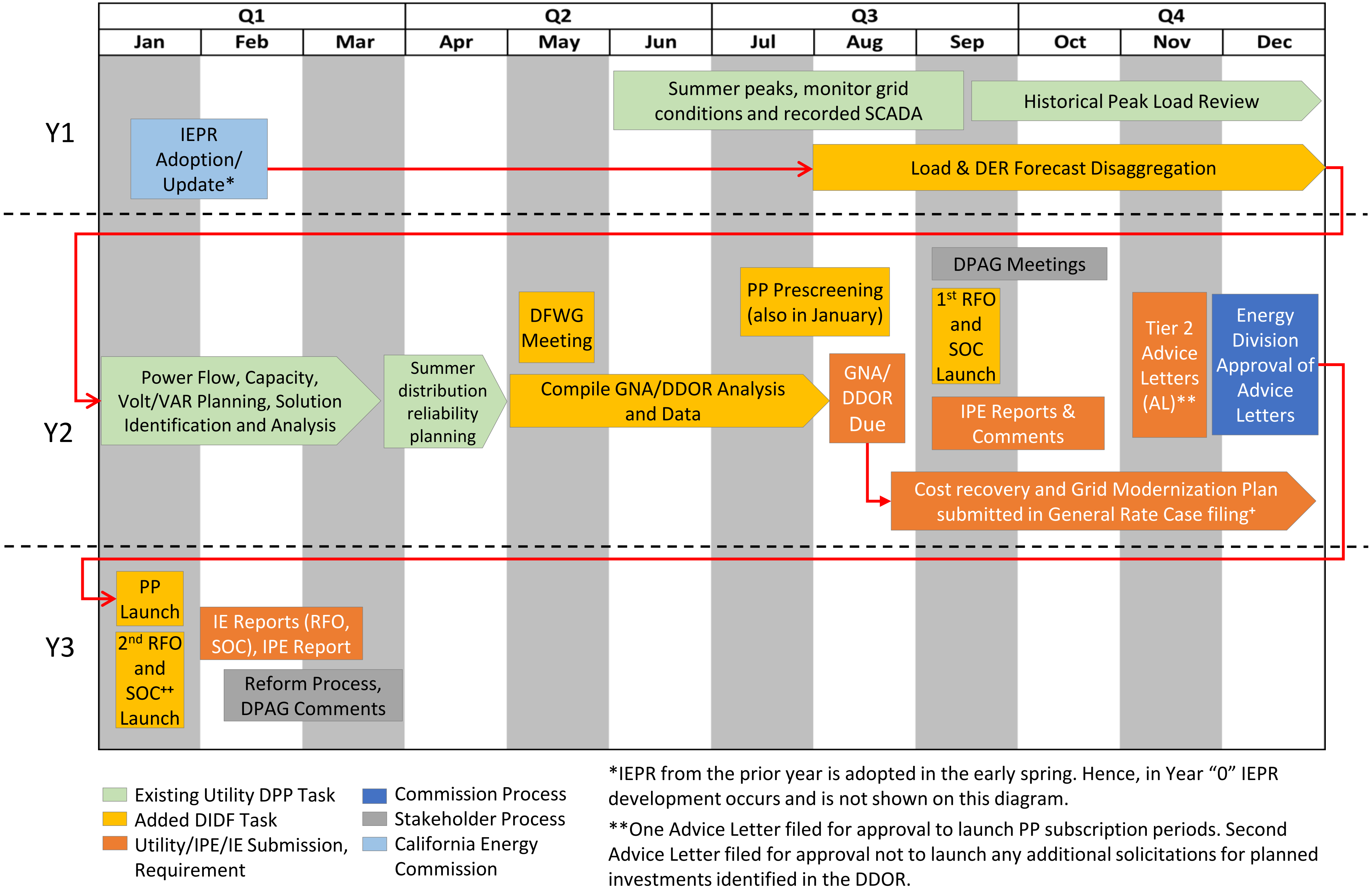
New Name	Baseline Forecast	Planning Forecast	Local Reliability Scenario
Previous Name	Mid Baseline Forecast	Mid-Mid	Mid-Low
Use Cases	• Baseline • Reference forecast	• Resource Adequacy • CPUC IRP • California ISO TPP economic, policy, and bulk system studies	• California ISO TPP local area reliability studies • Local capacity technical studies *DPP (anticipated)
Economic, Demographic, and Price Scenarios	Baseline (Mid)	Baseline (Mid)	Baseline (Mid)
AAEE Scenario	-	Scenario 3	Scenario 2
AAFS Scenario	-	Scenario 3	Scenario 4 plus SIP
AATE Scenario	-	Scenario 3	Scenario 3

Figure 24: Managed System Peak Demand (California ISO)



Source: 2022 Integrated Energy Policy Report, California Energy Commission (here)

Utility Distribution Planning Process and DIDF



- DIDF: Distribution Investment Deferral Framework
- DFWG: Distribution Forecasting Working Group
- DPAG: Distribution Planning Advisory Group
- GNA/DDOR: Grid Needs Assessment/ Distribution Deferral Opportunities Report
- IE: Independent Evaluator
- IEPR: Integrated Energy Policy Report (California Energy Commission "demand forecast")
- IPE: Independent Professional Engineer
- PP: Partnership Pilot
- RFO: Request for Offers
- SOC: Standard Offer Contract

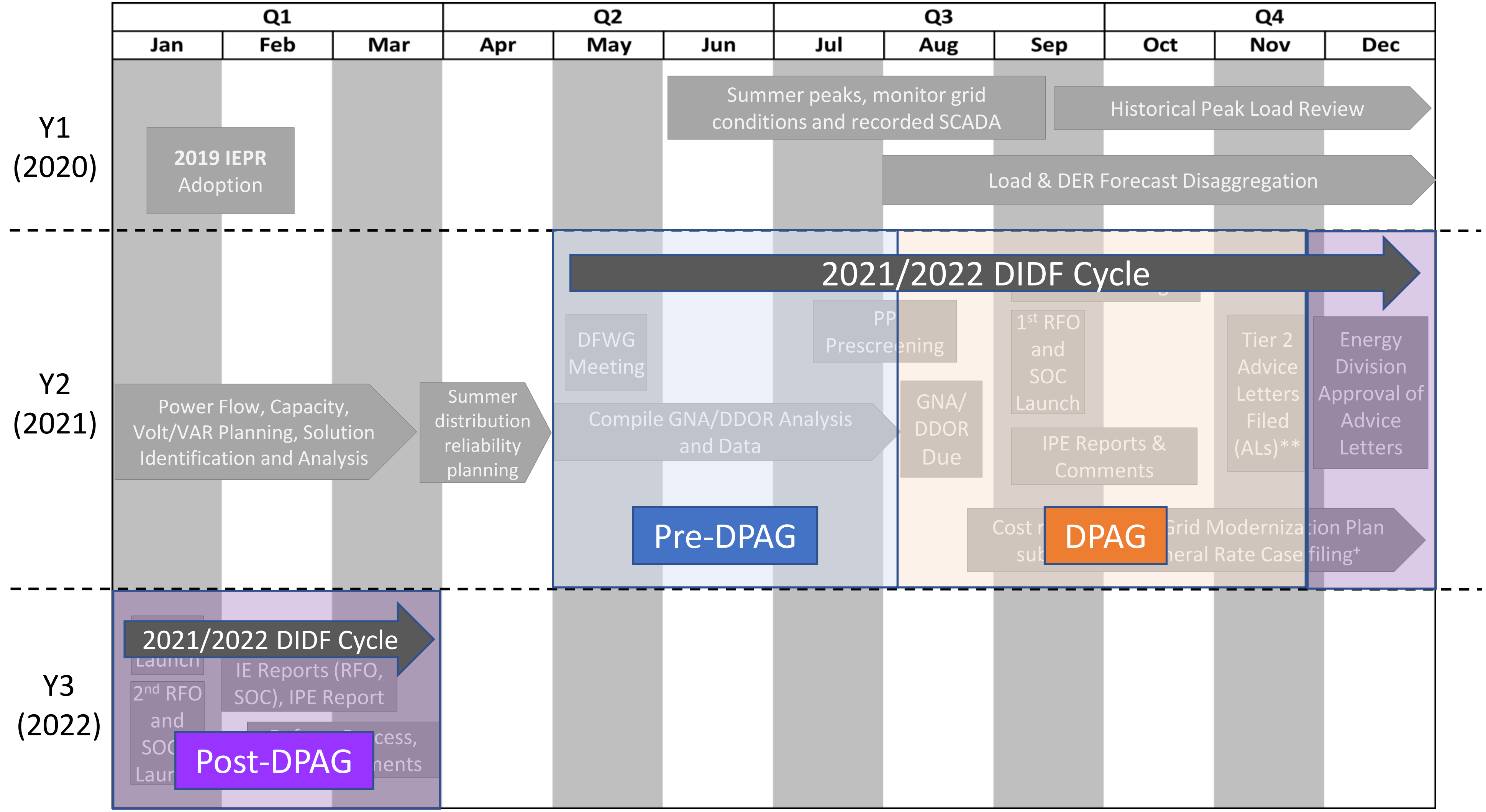
*IEPR from the prior year is adopted in the early spring. Hence, in Year "0" IEPR development occurs and is not shown on this diagram.

**One Advice Letter filed for approval to launch PP subscription periods. Second Advice Letter filed for approval not to launch any additional solicitations for planned investments identified in the DDOR.

+Utilities file General Rate Cases on quadrennial basis.

++Second RFO and/or SOC launches depend on outcome of Advice Letter filings.

DIDF Cycle and Distribution Planning Advisory Group (DPAG)



Note: A Y2/Y3 DIDF Cycle is shown with the pre-DPAG, DPAG, post-DPAG periods identified.

- Pre-DPAG, May to August 15th (in preparation for the GNA/DDORs filings)
- DPAG, August 15th to November 15th (to review GNA/DDOR filings)
- Post-DPAG, November 15th until end of procurement from the respective DIDF cycle (DER procurement and DIDF reform)

- DIDF: Distribution Investment Deferral Framework
- DFWG: Distribution Forecasting Working Group
- DPAG: Distribution Planning Advisory Group
- GNA/DDOR: Grid Needs Assessment/ Distribution Deferral Opportunities Report
- IE: Independent Evaluator
- IEPR: Integrated Energy Policy Report (California Energy Commission "demand forecast")
- IPE: Independent Professional Engineer
- PP: Partnership Pilot
- RFO: Request for Offers
- SOC: Standard Offer Contract

Key Takeaways

- The annual **GNA/DDOR filings are based on a State forecast prepared two years prior**.
  - e.g., The 2022 GNA/DDORs were based on the 2020 California Energy Commission demand forecast. The 2020 forecast was adopted in spring 2021.
- DER procurement to defer traditional infrastructure occurs after IOU DPPs. It may be that **DER procurement should be fully integrated into IOU DPPs** rather than occurring afterwards. This is being explored in the High DER proceeding.
- Further alignment between planned investment **costs identified annually in the GNA/DDOR filings and costs reported in the quadrennial General Rate Case filings** is needed for transparency, especially as project needs ramp up to meet electrification goals.
- **DIDF results (since 2018) have not been strong**. There are only a few examples of deferred traditional investments (only one operational as of 2022). Significant revision is likely necessary and is a key part of what's being investigated in the High DER proceeding.

ADDITIONAL SLIDES

A. DER Procurement Types for the DIDF

Request for Offers (RFO)

DIDF RFOs Launched in 2019, 2020, 2021, and 2022

- Designed to be a six-month procurement process from CPUC approval of RFO launch to contract execution
- Technology neutral, all cost-effective DER offers are accepted for evaluation
- Grid needs three years out are in the “sweet spot”

Challenges

- The RFO process typically takes longer than 6 months
- Contract negotiation is complex
- Grid needs change in the time it takes to execute a contract
- Limited or no BTM offers; the vast majority of offers have been FTM battery storage
- Procurement outcomes have been quite limited to date
- **Only one** deferral project operational as of 2022

Standard Offer Contract

Pilot started in September 2021, concurrent with (occurring in same month as) the 2021 DIDF RFO solicitation

- **Goal:** Pilot a new DER sourcing mechanism that streamlines the RFO process for procuring FTM DERs
- IOUs publish a price sheet (cost cap) for deferral projects; DER providers submit offers at or below the indicated price (simple auction pricing)
- If multiple offers with the same pricing, IOUs accept offers on a first come first served basis
- Contract terms and conditions are uniform and subject to limited modifications; negotiations are streamlined in comparison to RFOs
- Might replace the RFO process if pilot is successful (TBD)
- Pilot will last three years

Partnership Pilot

Program Goal

Increase opportunities for aggregations of BTM DERs to provide deferral services.

Overview

1. Utilities identify future grid need in a specific location of the distribution grid through the DIDF process
2. Customers in that location sign up to the program via Aggregators during the annual subscription period
3. Utilities communicate with Aggregators who then coordinate with BTM customers to collectively defer grid needs through dispatch of DERs
4. Procurement tranches (in MW) are defined on an annual basis
5. Cost cap set at 85% of the deferral value
6. Goal is to contract 120% of the grid need
7. Contracts execute if 90% of the grid need is met by offers
8. Pilot will last five years
9. First subscription periods to launch January 2022

Partnership Pilot: Tiered Payment Structure

Payment Tier	Percent of Project Budget	Description
Deployment Payment	20%	Upfront payment to customers who enroll and commit to operating their *new* DER(s) to provide a capacity service. Customers with existing DERs are not eligible for this payment.
Reservation Payment	30%	Customer paid to hold capacity in reserve if called during specified deferral season.
Performance Payment	50%	Customer paid to dispatch in response to a specified service event, as defined in the tariff.

Partnership Pilot: Example

- **Scenario**: A neighborhood in a Utility's service territory is expected to add new homes, businesses, and retail buildings that are forecast to exceed distribution line capacity. Forecasted grid need is 1.25 MW by 2026.
- **Planned Investment**: Utility designs a traditional investment to address the capacity need. The capacity need is forecast for 2023 and to steadily increase each year (see table).
- **Deferral Opportunity**: The planned investment is suitable for a non-wires alternative and ranked highly by the IOUs in their DDOR.
- **Deferral Value (i.e., Cost Cap):** The maximum DER expenditure that is cost-effective in comparison to the traditional planned investment
- **Ratable Procurement:** The grid need is broken into increments with annual procurement goals (i.e., procurement tranches)

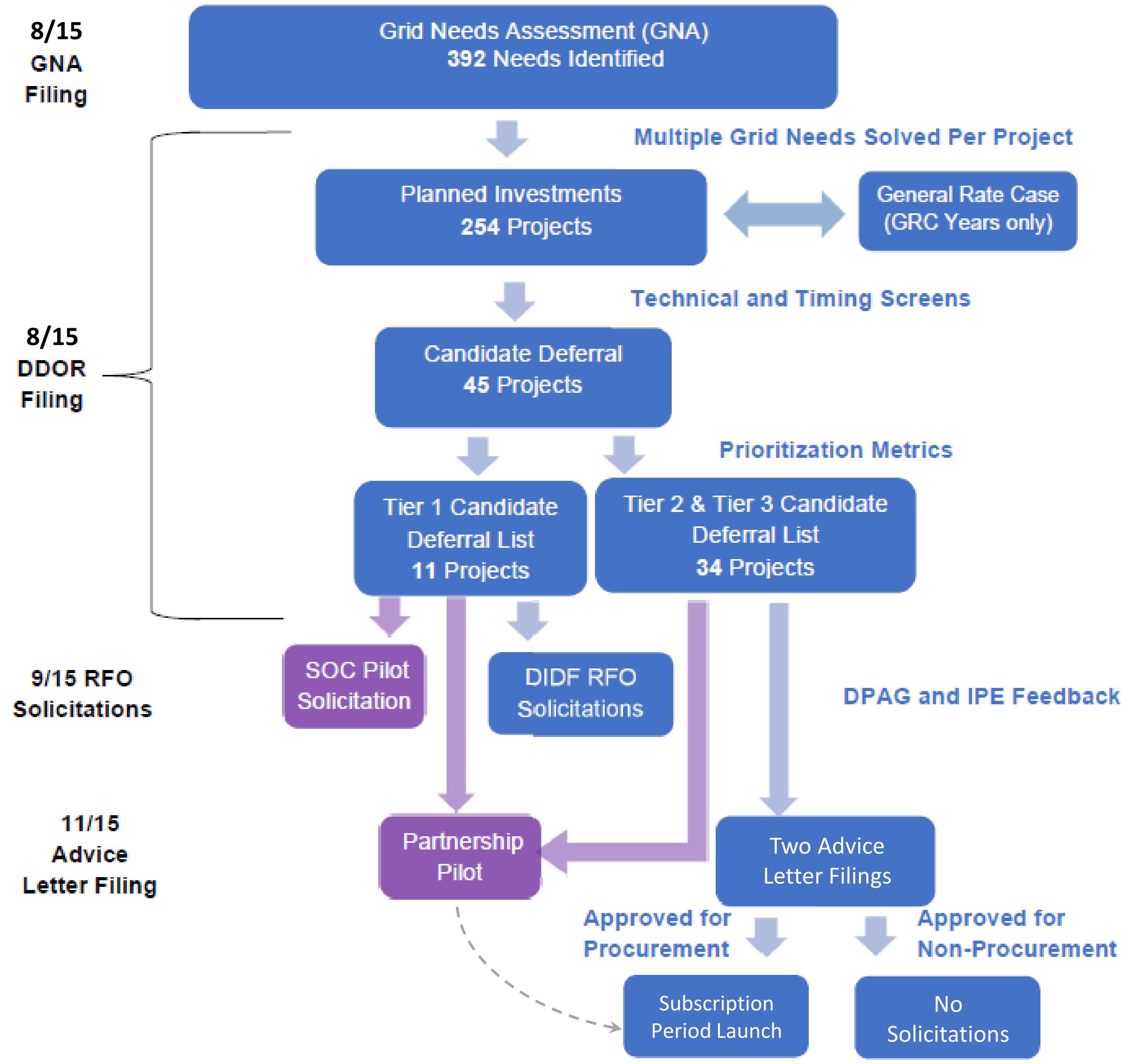
	2021	2022	2023	2024	2025	2026	Total
Forecast Grid Need	0	0	0.25	0.25	0.5	0.25	**1.25**
Annual Procurement Goal	0	0.25	0.25	0.5	0.25	0	**1.25**

SCE Partnership Pilot Example (2021 DDOR)

Table 26: New Circuit at El Casco Substation Project Procurement and Tariff Budget Parameters (Proportional Smoothing Payment Design)

Tranche	Tranche Procurement Goal (Capacity - MW)	Tranche Procurement Goal (Energy - MWh)	Subscription Period Launch Date	Contingency Date/Subscription Period End Date	Operating Date
1	0.1	0.1	1/15/2022	12/1/2022	6/1/2024
2	0.3	0.6	1/15/2023	12/1/2023	6/1/2025
3	0.4	0.7	1/15/2024	12/1/2024	6/1/2026
4	0.4	0.6	1/15/2025	12/1/2025	6/1/2027
5	0.3	0.5	1/15/2026	12/1/2026	6/1/2028
6	0.3	0.3	1/15/2027	12/1/2027	6/1/2029
7	0.3	0.4	1/15/2028	12/1/2028	6/1/2030
Tranche	**Deferral Value (Cost Cap)**	**Tariff Budget**	**Deployment Budget**	**Reservation Budget**	**Performance Budget**
1	$66,956	$10,228	$2,046	$3,068	$5,114
2	$62,512	$61,365	$12,273	$18,410	$30,683
3	$58,363	$71,593	$14,319	$21,478	$35,796
4	$54,490	$61,365	$12,273	$18,410	$30,683
5	$50,874	$51,138	$10,228	$15,341	$25,569
6	$47,497	$30,683	$6,137	$9,205	$15,341
7	$44,345	$40,910	$8,182	$12,273	$20,455
	Total Tariff Budget	$327,281			

B. Utility Filing Excerpts



Cost Effectiveness
relative indication of how likely DER resources can cost effectively defer a Planned Investment (Locational Net Benefit Analysis)

Forecast Certainty
relative indication of the certainty of the forecasted grid need (e.g., year of grid need, distribution engineer questionnaire)

Market Assessment
relative indication of how likely DER resources can be sourced that will successfully meet the DER Service Requirements (e.g., duration of need, number of grid needs to meet, number of customers)

Results ranked into Tiers 1-3 with Tier 1 having best chance at successfully deferring the planned investment.

Excerpt from Grid Needs Assessment Spreadsheets

GNA ID	Substation / Subtransmission Line	Circuit	Distribution Service Requir	Primary Driver of Grid Need	Operating	Deficiency (MW, MVAR, or Vpu)[1] 2021	2022	2023	2024	2025
GNA_2021_309	Valley 'EFG' 500/115 (S)	null	Capacity	Demand Growth	1/29/2026	0.00	0.00	0.00	3.30	9.80
GNA_2021_81	Eisenhower 115/33 (D)	Crossley	Capacity	Demand Growth	6/1/2024	0.00	0.00	0.00	2.87	2.81
GNA_2021_82	El Casco 115/12 (D)	Jonagold	Capacity	Demand Growth	6/1/2024	0.00	0.00	0.00	0.07	0.30
GNA_2021_86	Elizabeth Lake 66/16 (D)	Oboe	Capacity (UCT)	Demand Growth	6/1/2021	0.00	1.80	4.23	1.53	2.22

Excerpt from Distribution Deferral Opportunity Report Spreadsheets

GNA ID	DDOR ID	Tier	DDOR Project ID	Substation/Subtransmission line	Circuit
	DDOR_2021_D159	1	DDOR_2021_7978_959298	Elizabeth Lake 66/16 (D)	Guitar
GNA_2021_86	DDOR_2021_D160	1	DDOR_2021_7978_959298	Elizabeth Lake 66/16 (D)	Oboe
	DDOR_2021_D161	1	DDOR_2021_7978_959298	Elizabeth Lake 66/16 (D)	Trumpet
GNA_2021_82	DDOR_2021_D167	1	DDOR_2021_8057_331531	El Casco 115/12 (D)	Jonagold
GNA_2021_81	DDOR_2021_D178	1	DDOR_2021_8144_079630	Eisenhower 115/33 (D)	Crossley

Deficiency (MW, MVAR or VPU)											
2021[A]	2022[A]	2023[A]	2024[A]	2025[A]	2026[A]	2027[A]	2028[A]	2029[A]	2030[A]	Units	DER Eligible Service
0.00	0.00	0.00	0.00	0.00	0.00	0.49	1.33	1.26	1.20	MW	YES
0.00	0.00	0.92	1.53	2.10	2.61	2.88	3.10	3.27	3.46	MW	YES
0.00	0.00	0.00	0.00	0.00	1.84	0.00	4.22	0.30	1.05	MW	YES
0.00	0.00	0.00	0.07	0.30	0.37	0.35	0.30	0.28	0.26	MW	YES
0.00	0.00	0.00	2.87	2.81	2.75	2.69	2.63	2.57	2.51	MW	YES

Excerpt from Joint Prioritization Metrics Workbook ("joint" = same approach for SCE, PG&E, and SDG&E)

Raw Data									Step 6: Determine Final Score and Ranking		
DDOR Project ID	Project Description	Unit Cost of Traditional Mitigation ($)	Grid Need Certainty	Operating Date (Info Only)	Year of Need	Duration (Hours)	Capacity Need (MW)	Number of Grid Needs	Final Score	Final Ranking	Final Tiering
DDOR_2021_6092	Alberhill System Project	500,250,040.00	11.87	2026	2024	4	63.40	1	3.91	1	Tier 3
DDOR_2021_7978_959298	New Circuit at Elizabeth Lake	8,940,611.00	22.30	2024	2023	11	4.22	3	3.68	2	Tier 1
DDOR_2021_8057_331531	New Circuit at El Casco	501,178.00	15.00	2024	2024	2	0.37	1	2.96	3	Tier 1
DDOR_2021_8299_479084	New Circuit at Farrell	1,343,065.00	17.00	2024	2024	10	3.80	1	2.62	4	Tier 2
DDOR_2021_TSPSTL34806	Santa Clara-Colonia 66kV Subtr	23,816,611.00	16.59	2025	2025	14	22.30	1	2.47	5	Tier 2
DDOR_2021_8325_339553	New Circuit at Gonzales	2,324,591.00	18.00	2025	2025	20	8.15	2	2.27	6	Tier 2
DDOR_2021_8359_434553	New Circuit at Kimball	2,175,087.00	19.00	2024	2024	24	9.04	6	2.26	7	Tier 3
DDOR_2021_DSP34626_534551	New Circuit at Soquel	7,058,536.00	17.09	2025	2025	24	4.39	5	2.00	8	Tier 2
DDOR_2021_8252	Saugus-Colossus-Lockheed-Pitc	10,787,493.00	13.36	2025	2025	10	20.20	1	1.97	9	Tier 2
DDOR_2021_8144_079630	New Circuit at Eisenhower	2,707,665.00	11.87	2024	2024	6	2.87	1	1.92	10	Tier 1
DDOR_2021_6652	Saugus-Elizabeth Lake-MWD Fo	3,689,274.00	13.36	2025	2025	10	19.70	1	1.92	11	Tier 2
DDOR_2021_DSP34729	Shawnee Transformer Upgrade	1,578,053.00	11.87	2024	2021	7	7.00	1	1.80	12	Tier 2
DDOR_2021_4800	Del Valle 66/16 kV Substation	91,029,207.00	12.00	2028	2028	24	46.60	2	1.01	13	Tier 2
DDOR_2021_8256	Cal City Upgrade	332,664,368.00	11.87	2028	2028	24	76.80	2	0.92	14	Tier 2
DDOR_2021_DSP33756_473036	New Circuit at Roadway	312,940.00	11.87	2024	2024	24	8.66	1	0.89	15	Tier 3
DDOR_2021_6030	Valley-Ivyglen Subtransmission Line										

C. Online Resources

- High DER Grid Planning Proceeding (Successor to DRP; R.21-06-017)
- DIDF Retrospective Blog
  - https://gridworks.org/category/drp-retrospective
- Distribution Resources Plan (DRP) Proceeding (R.14-08-013)
- Integrated Distributed Energy Resources (IDER) Proceeding (R.14-10-003)
- News Articles
  - https://www.utilitydive.com/news/california-begins-brainstorming-approaches-to-a-high-der-grid-of-the-future/605309/
  - https://www.greentechmedia.com/articles/read/californias-plan-to-crowdsource-distributed-energy-to-replace-grid-upgrades
  - https://microgridknowledge.com/california-non-wires-alternatives-ders/
  - California regulators modify grid map requirements to ease solar integration – pv magazine USA (pv-magazine-usa.com)
- CPUC Deferral Tariff Final Decision (Partnership Pilot and Standard Offer Contract pilot)
  - https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=365628213
- Assembly Bill 327, Section 8, Perea 2013 (led to DRP and IDER proceedings)
  - Bill Text - AB-327 Electricity: natural gas: rates: net energy metering: California Renewables Portfolio Standard Program.
- Public Utilities Code 769 (led to DRP and IDER proceedings)
  - Law section (ca.gov)