Price-Based Demand Response as a Resource in Electricity System Planning

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Session 6: Price-based Demand Flexibility

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Agenda

- Study motivation and approach
- Price-based DR in integrated resource planning
  - Findings
  - Recommendations
- Price-based DR in distribution system planning
  - Current practices
  - Recommendations

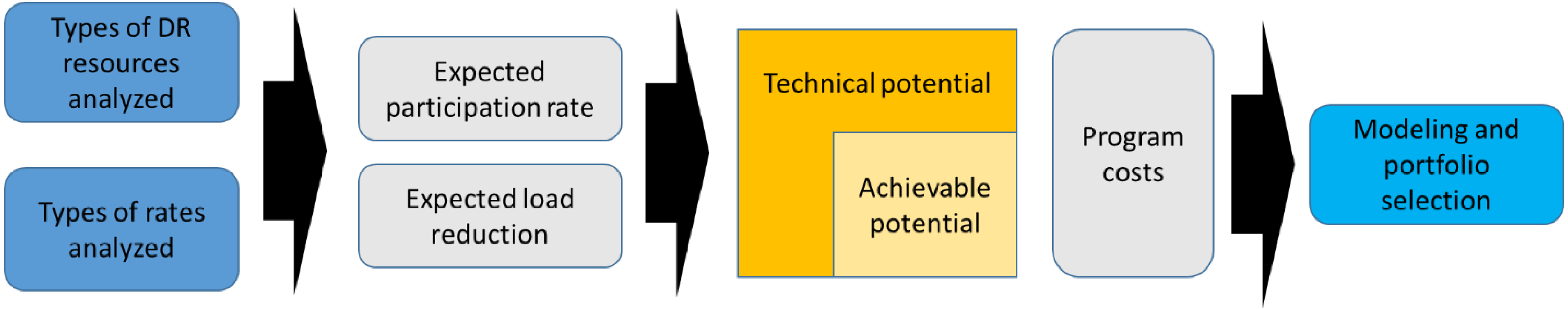
Technical brief: *The use of price-based demand response as a resource in electricity system planning*

Additional research on resource and distribution planning: https://emp.lbl.gov/bulk-power-system-planning-procurement-market-processes

Study Motivation and Approach

Study Approach

- **Integrated resource planning**
  - Examined state requirements for IRPs and 12 recently filed plans by U.S. electric utilities in the West, Midwest, and Southeast
  - Analyzed price-based DR in these IRPs using the following framework



- **Distribution system planning**
  - Reviewed DR-related provisions in state requirements for regulated utilities to conduct DSP
  - Reviewed nascent utility practices for DSP in 6 states: California, Colorado, Hawaii, Minnesota, New York, and Oregon

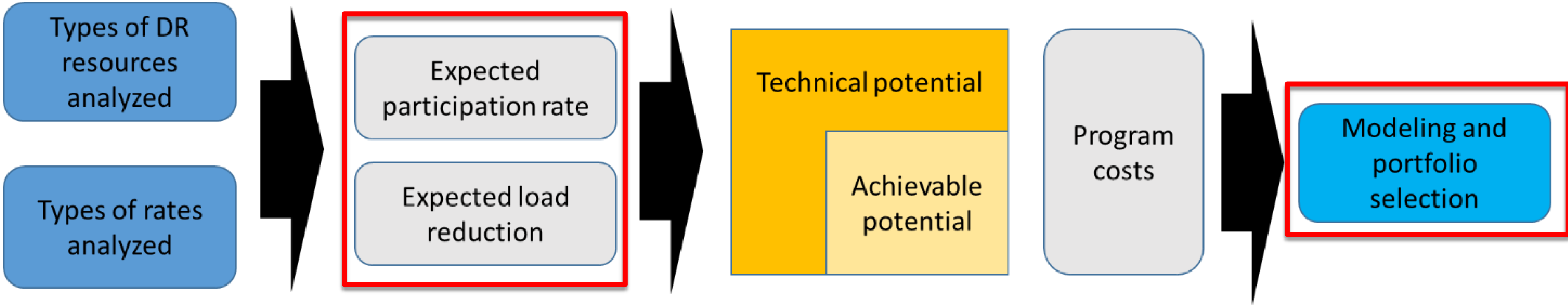
Time-Varying Rates - Refresher

- The U.S. Energy Information Administration defines time-based rate programs, aka "time-varying rates," as those "designed to modify patterns of electricity usage, including the timing and level of electricity demand."
- **Time of Use (TOU)** – Customers pay different prices at different times of day
- **Real Time Pricing (RTP)** – Retail electricity price fluctuates hourly or more often to reflect changes in the wholesale price of electricity, on either a day-ahead or hour-ahead basis
- **Variable Peak Pricing (VPP**) – Prices set on a daily basis
- **Critical Peak Pricing (CPP)** – Encourages reduced consumption during periods of high wholesale market prices or system contingencies, using a pre-specified high rate or price for limited number of days or hours
- **Critical Peak Rebate (CPR)** – Same intent, but provides a rebate to the customer on a limited number of days and for a limited number of hours

Definitions adapted from Form EIA-861S Annual Electric Power Industry Report

Price-Based DR in Integrated Resource Planning: Findings and Recommendations

Focus on Two Key Inputs



Expected Participation Rate

- 2/3 of utilities **clearly report participation rates** by type and customer segment
- Only one **distinguished opt-in vs opt-out →** really matters!
- Only one considered **low/high values** for this potentially uncertain variable
- **Data sources not transparent**, but *remarkable* consistency for lower & higher values
- **Opt-out values lower than literature**
- How utilities **determine customer preferences** with multiple rate options unclear

Utility ID	Res-TOU	Res-CPP	Res-VPP	C&I-TOU	C&I-CPP	C&I-RTP
1	13% opt-in; 74% opt-out	-	25%	13% opt-in; 74% opt-out	-	-
2	-	15% eligible load	-	10% eligible load	-	-
3	28% opt-in	17% opt-in	-	13% opt-in	18% opt-in	3-5% opt-in
4	-	-	-	-	~10% (ind)	-
5	30% (low); 75% (high)	-	7% (low); 24% (high)	10% (low); 22% (high)	-	5% (low); 10% (high)
6	27%	-	-	14% (comm); 22% (ind)	-	-
7	~70%	-	-	-	-	-
8	36%-64%	-	-	-	23%-50%	-

Expected Load Reduction per Participant

- Reporting reveals the **diversity of variables** that inform load reductions
  - Opt-in vs opt-out, season, DLC or other enabling technologies, other
- **Unclear** how load reductions **contribute to peak demand** or resource adequacy — unexplained derating
- **Scant information on sources for these values**

Utility ID	Res-TOU	Res-CPP	Res-VPP	C&I-TOU	C&I-CPP	C&I-RTP
1	4.6% summer; 1% winter					
2	5.7% (opt-in); 3.4% (opt-out)		10%	3.1% (opt-in); 2.6% (opt-out)	4%	
3		12% no DLC; 40% with DLC			5% no DLC; 7% with DLC	
4	5.7% summer; 2.9% winter	12.5% summer; 7.5% winter		~3% summer; ~1.5% winter	~7% summer; ~4% winter	~7% summer; ~4% winter
5					20%	
6	12%		10%	5%	20%	13%
7	4% (low); 5.3% (high)					
8		9%			11%	

Levelized Cost of Capacity (LCOC)

- Fixed and variable costs can be **aggregated** and **coupled** with achievable potential to **estimate LCOC**
- LCOC can be **compared against other capacity resources** and cost of new entry (CONE) determined for ISO/RTO (if relevant)
- Capacity costs are **very low** compared to CONE or to other resources in IRP
- LCOC varies substantially across utilities, even for standard rates like Res-TOU

Utility ID	Res-TOU	C&I-TOU	Res-CPP	C&I-CPP	Res-VPP	C&I-RTP
1	$80-$100/kW-yr				$33-$59/kW-yr	
2			-$3 to -$8/kW-yr	$81-$86/kW-yr		
3				$22/kW-yr		
4	$16/kW-yr				$10/kW-yr	$8/kW-yr
5	$7/kW-yr	$14 $18/kW-yr				
6	$14-$36/kW-yr	$6-$8/kW-yr				
7				$71/Kw-YR		

Treatment of Price-Based DR as a Resource in IRP: Shortcomings

- The way price-based DR is considered in the portfolio analysis in IRP reports reviewed is **hard to track at best and unclear in general**

- Common **shortcomings** in current IRP practices for preferred portfolio selection related to price-based DR
  - **Lack of transparency** in type of price-based DR modeled
  - **Rationale for level of price-based DR adopted**
  - Treating price-based DR as a **load reduction**
  - **Lack of use of supply curves** or lack of transparency
  - **Low capacity** assigned to price-based DR, and amount selected, is **unsupported**

Recommendations for IRP improvement – DR and Rate Types

- Types of DR
  - **Do not screen out** price-based DR due to “unpredictability”; demonstrate predictability with rigorous analysis

- Types of rates
  - Study impacts of **enabling technologies** to increase price-based DR potential
  - Support the load reduction potential with a **thorough characterization of the rates’ price differential and timing assumptions**

Figure: Institute for Electric Innovation

Recommendations for IRP improvement – Participation/Load reduction rates

- Participation rate
  - Estimate and assess participation rates for **opt-in and opt-out** versions of price-based DR
  - Distinguish **short-term vs long-term participation rates**, with the latter not limited by acquisition efforts

- Load reduction rates
  - **Transparently** and **rigorously** report empirical data or models used to inform **load reduction rates**
  - Make load reduction rates **consistent with capacity credit** for price-based DR. Ideally, **estimate the effective load carrying capability** (ELCC) of price-based DR to make it comparable to any other IRP resource

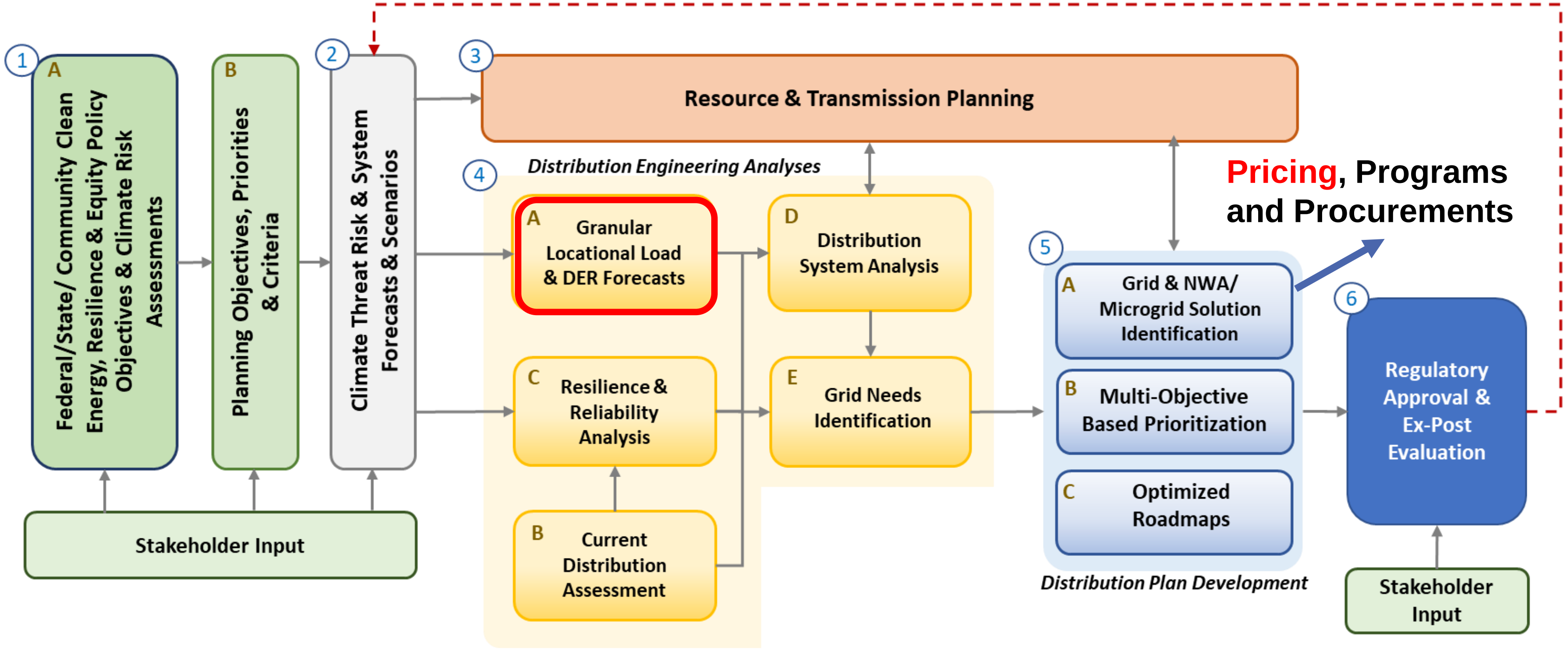
Price-Based DR in Distribution System Planning: Findings and Recommendations

Integrated Distribution System Planning Framework

If a utility considers price-based DR in distribution planning, it's typically through **geographically-targeted forecasting**, **pricing & program pilots**, and **non-wires alternative (NWA) procurements**.

Needs met by price-based DR include:

- **Load relief (deferral value)**
- **Voltage regulation**
- **Resilience**
- **Electrification upgrade cost containment**



Source: P. De Martini et al. *Integrated Resilient Distribution Planning*, prepared for U.S. Department of Energy, 2022

For a municipal utility or rural electric cooperative, "Regulatory Approval" is the approving board.

Example Recommendations for Considering Price-Based DR in DSP*

- **Evaluate price-based DR** to defer certain distribution investments and meet new loads
- **Add a dynamic rate** to help address local distribution events
- Improve **grid data** and make it publicly available
- Apply **advanced planning tools**
- Use a **longer planning horizon**
- Conduct ***systematic* studies** of the locational value of DR to target price-based DR, reducing load growth in certain areas and the risk that distribution system upgrades will be needed

*See technical brief for additional and detailed recommendations

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For more information

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Additional Slides

Locational Value of Price-Based DR

Price-based DR, **geographically-targeted**, can help meet distribution system needs, including for load relief, voltage regulation, and resilience.

- Potential value of DR at a specific location is determined by:
  - **Capability** to provide needed grid services at that location
  - **Potential avoided costs** of traditional utility distribution investment
- **Deferral value** is the primary location-specific benefit
  - DR must operate at **specific times and locations** where there is a risk that distribution capacity is insufficient to meet expected future needs
- **Electrification** and increasing levels of **distributed generation** are driving investments in distribution systems
  - Accurately valuing all potential solutions — including price-based DR — is increasingly important to **keep down distribution system costs**

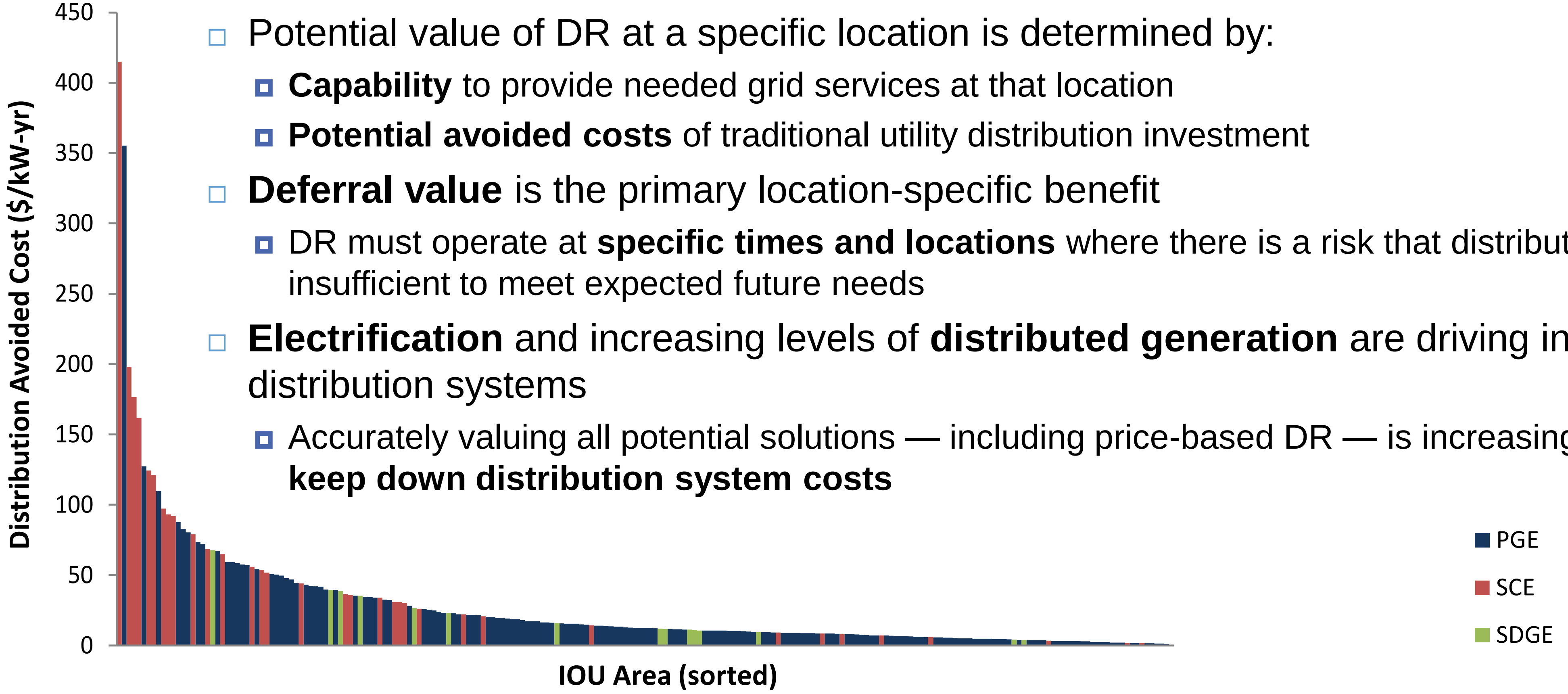
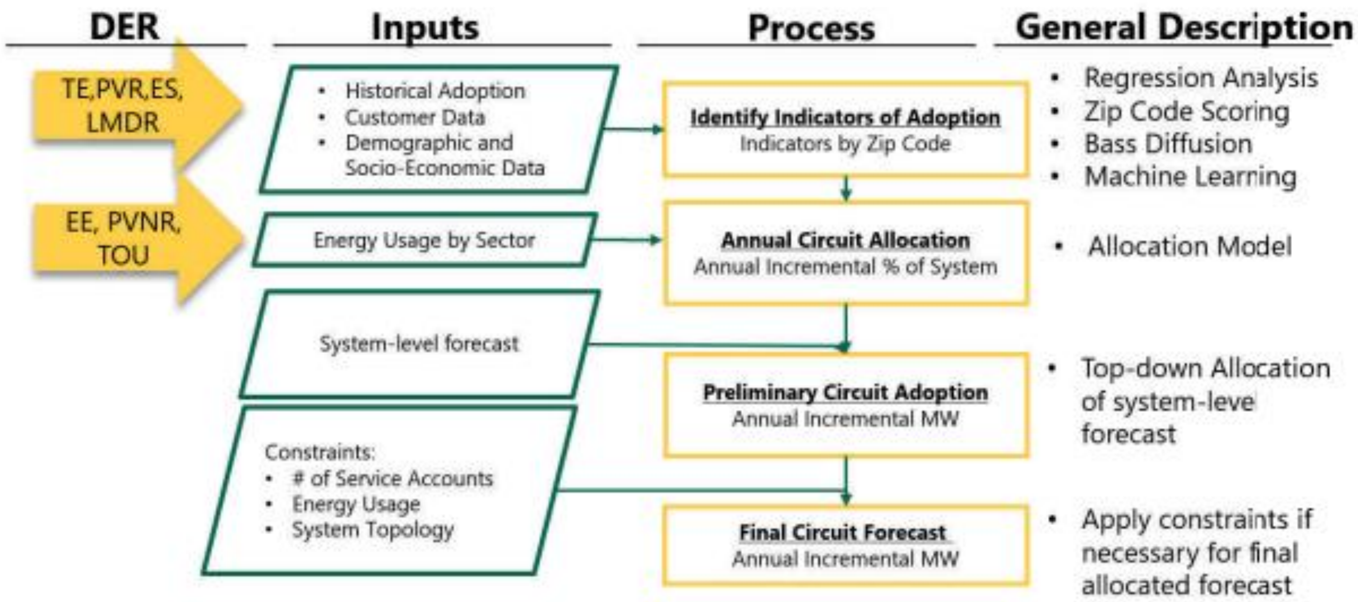


Figure: E3. 2012. Technical Potential for Local Distributed Photovoltaics in California

Considering Price-Based DR in Distribution Plans (1)

Utility load forecasts can be disaggregated by location.

- Utilities can consider impacts of price-based DR on future loads at system and substation circuit level
  - Hawaiian Electric [2023 Integrated Grid Plan] evaluates **impact of residential TOU forecasts on a range of modeling scenarios**
  - California investor-owned utilities **allocate to distribution circuits** utility-wide forecasts from the California Energy Commission for efficiency, solar PV, energy storage, demand response, and time-based rates. For example, [SCE] disaggregates system-level "Load-modifying DR" (defined as CPP) to develop circuit-level forecasts.

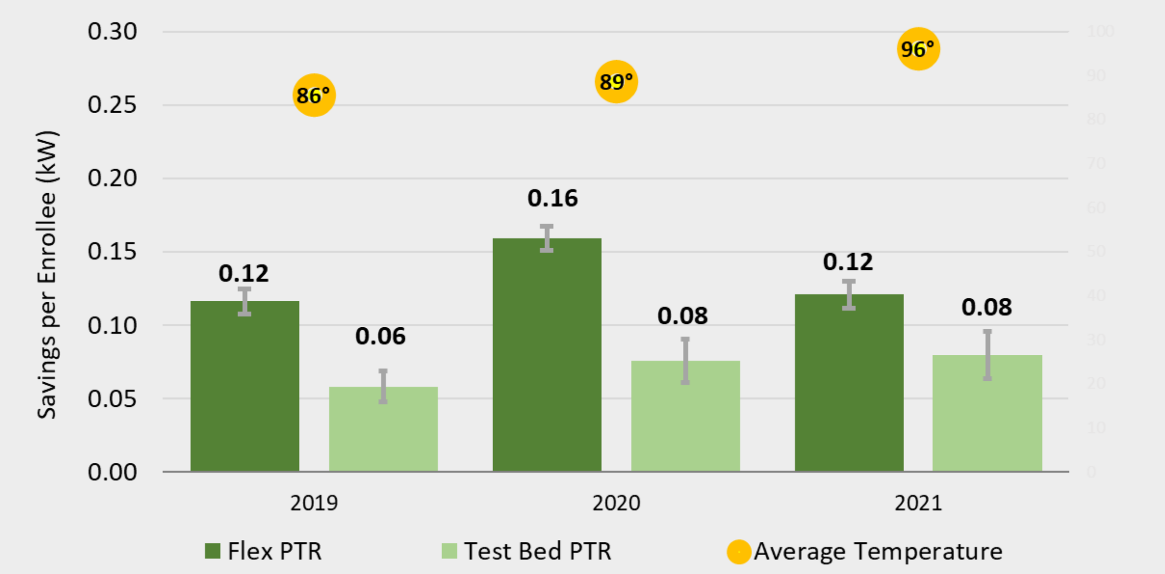


Considering Price-Based DR in Distribution Plans (2)

Utilities can use location-based price signals in pricing pilots/programs.

- Southern California Edison (SCE) Flexible Pricing Rate Pilot
- San Diego Gas & Electric Power Your Drive program for Level 2 charging ports at workplaces and multi-family dwellings
- Xcel Energy Geotargeted Distributed Clean Energy Initiative
- Consolidated Edison Smart Home Rate Demonstration Project
- Portland General Electric (PGE) Smart Grid Test Bed, with peak time rebate (PTR)

PGE Average Summer Demand Savings (kW) by PTR Group



Flex PTR – opt in; Test Bed PTR – opt out for 3 substation neighborhoods

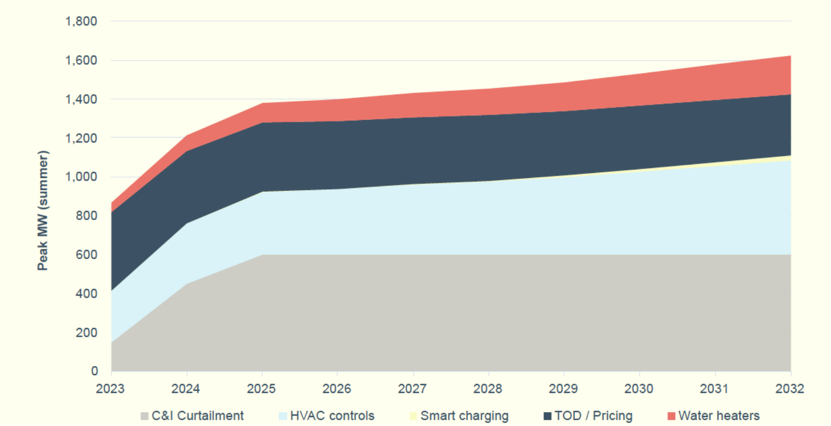
Considering Price-Based DR in Distribution Plans (3)

NWAs (aka *non-wires solutions*)

- May be a single large distributed energy resource (e.g., battery) or a portfolio of DERs
- To provide load relief, reduce interruptions, address voltage issues, enhance resilience, or meet local energy needs
- NWA analysis is after grid needs assessment to determine the location and timing of constraints on the distribution system
- *Example:* Portland General Electric (PGE) demonstrated that opt-in time of day (TOD) and peak time rebate — combined with programmatic approaches to DR, EE, PV and storage — could provide sufficient capacity relief for Eastport substation

- Typical steps for NWA procurement:
  1. Identify eligible DER types
  2. Screen NWA using standard criteria
  3. Conduct cost-effectiveness analysis
  4. Procure solution
     - Typically through utility solicitations for 3rd party solutions
- Price-based DR does not fit into typical NWA procurement processes
  - Utility is responsible for retail rates.

Flexible Load & DR Potential: Eastport Substation



Sources: PGE 2022 IDP and flexible load study