Energy Efficiency and Demand Response as Resource Options in Bulk Power System Planning

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Agenda

- Methods to consider energy efficiency (EE) and demand response (DR) in long-term electricity planning
- Changes to load forecasting and resource potential assessments processes
  - Energy efficiency and demand response supply curve examples
- Changes to capacity expansion modeling
  - Efficiency and demand response modeling results
- Valuing demand flexibility from distributed energy resources (DERs)
- Questions states can ask

Methods to incorporate EE and DR in electricity system planning and markets

- Electric utilities, independent system operators and regional transmission operators (ISO/RTOs) have acquired significant levels of EE and DR over several decades.
- Increasing levels of wind and solar, growth in peak demand, and electrification of transportation and other loads have increased the need for time-sensitive evaluation of EE and a more flexible and resilient electricity system.

Typically, EE and DR are load forecast adjustments in long-term electricity planning

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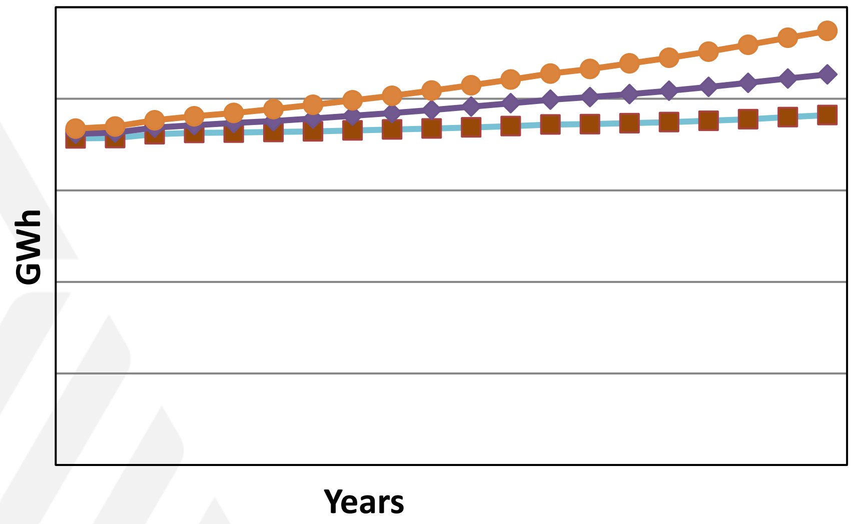
- Load forecasts project future electricity consumption and peak demand.
- In vertically integrated states, utilities conduct resource planning to evaluate the timing and allocation of different types of supply and demand resources to reliably meet projected loads.



- In restructured states, ISOs and RTOs operate markets to determine which resources will be dispatched during each hour of the day.*
- In both these approaches, the basic technique for incorporating efficiency into the planning process is to reduce the load forecast by an estimated quantity.

*EE and DR can bid into forward capacity markets, where they exist, subject to eligibility rules.

Why model efficiency, demand response and other DERs as selectable resources?

- Integrated Resource Planning (IRP) is intended to evaluate multiple resource portfolio options in an organized, holistic, and technology-neutral manner and normalize solution evaluation across generation, distribution, and transmission systems and demand-side resources.
- In this framework, DERs are a decision variable directly comparable to amounts and timing of generation options. This allows for consideration of relative cost and risk across the broadest array of potential solutions.
- Modeling energy efficiency and other DERs as resource options for bulk power systems can support many state objectives, including greater reliability and resilience, reduced electricity costs, achieving energy efficiency and renewable energy targets, and lower air pollutant emissions.

Typically, IRPs determine the amount and timing of EE and DR development in a 6-step process.

- Step 1 – Estimate *technical potential* on a *per application* basis (i.e., savings per unit)
- Step 2 – Estimate *economic potential* on a *per application* basis (i.e., levelized cost per unit) based on "avoided cost" of a "proxy" resource or capacity expansion model marginal resource analysis
- Step 3 – Estimate *number of applicable units* (account for physical limits, retirements, new construction, etc.)
- Step 4 – Estimate *economic potential* for *all applicable* units
- Step 5 – Estimate *economically achievable* potential for *all realistically achievable* units
- Step 6 – **Reduce the load forecast provided to the capacity expansion model** by the amount of *economically achievable* savings (determined in Step 5) before the model is used to "optimize" supply side resources

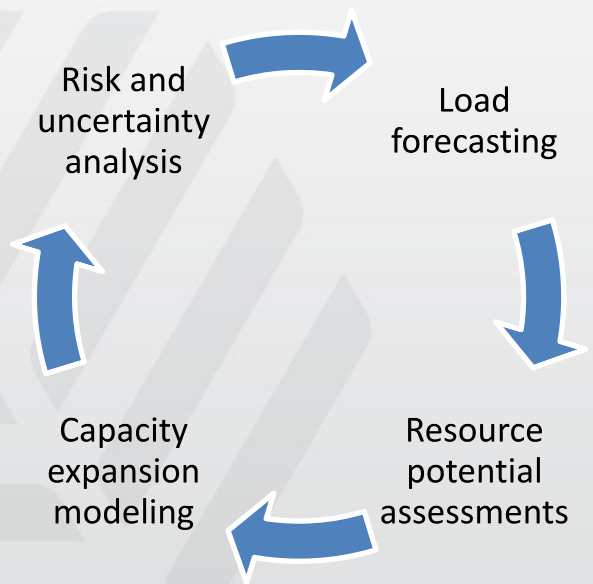
The process and order are different when considering EE and DR as selectable resources in IRPs.

- Step 1 – Estimate *technical potential* on a *per application* basis (i.e., savings per unit)
- Step 2 – Estimate *number of applicable units* (account for physical limits, retirements, new construction, etc.)
- Step 3 – Estimate *technical potential* for *all applicable* units
- Step 4 – Estimate *achievable potential* for *all realistically achievable* units
- Step 5 – Estimate *economic potential* for *all realistically achievable* units **by competing EE and DR against supply side resources in capacity expansion modeling***

*Any Energy Efficiency Resource Standard (EERS) requirements are typically modeled as "must build" resources. Only additional increments above EERS requirements compete against generating resources in capacity expansion modeling.

Changes to long-term electricity planning may be needed to appropriately consider EE and DR

- Using EE or DR as a selectable resource requires a different process than using these resources as a decrement to the load forecast.
- Allowing a capacity expansion model to select EE and DR resources permits optimization between *all resources* (e.g., supply and demand side).
- Today, I will focus on changes that may be needed in load forecasting, resource potential assessments — including valuation of EE and DR, and capacity expansion modeling to select the optimal levels of EE and DR for resource portfolios.



Internal consistency between load forecasting and EE and DR assessments

- Whether a load decrement or direct competition approach is used, internal consistency between the load forecast and EE and DR potential assessments is necessary to avoid the potential for *over* or *under* estimating remaining EE and DR potential.
  - Baseline use and efficiency assumptions should be equivalent.
  - "Units" (e.g., houses, commercial floor space, appliance counts) should be identical.
- Internal consistency is most readily achieved when end-use and statistically adjusted engineering (SAE) load forecasting models are used.
  - When econometric load forecasting models are used, "calibration" between the load forecast and EE potential assessments is typically at the sector (i.e., residential, commercial) level.
  - The typical method is translating measure-level EE savings (in kWh) derived from the potential assessment to percent improvements from a baseline and reducing the load forecast by these percentages.

Load forecasting considerations for direct competition method

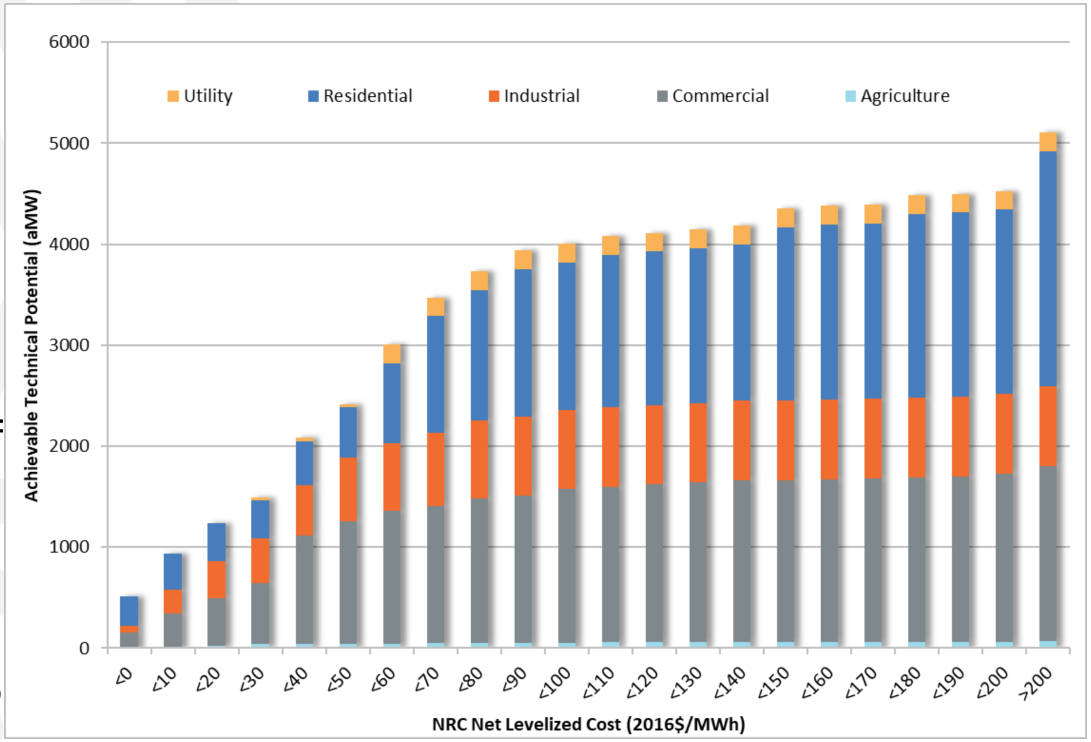
- Load forecast is not decremented with an assumed level of EE and DR
  - Known codes and standards and “must-run” resources such as EERS requirements are included in the load forecast.
- Baseline load forecast used in capacity expansion/resource optimization model assumes “frozen efficiency” (i.e., no price-responsive improvements occur) — only efficiency improvements from stock turnover and known codes and standards
- EE and DR costs should reflect all utility system impacts not accounted for in capacity expansion resource optimization process — for example:
  - The capacity expansion model does not estimate the value of deferred transmission and distribution, therefore EE and DR levelized cost inputs for model should be “net” of deferred T&D.
  - If non-energy benefits, such as the value of water savings, are to be included in EE valuation, the levelized cost input for the model should be “net” of the value of such benefits.

Improvements for resource potential assessments

- The objective of EE and DR potential assessments is to provide accurate and reliable information on:
  - Quantity of EE and DR available
  - Timing of availability (e.g., new construction, stock turnover)
  - EE and DR measure cost
  - Load or savings shape
- EE/DR resource potential assessment improvements:
  - Resource quantity is not constrained by assumed levels of required consumer cost-sharing (i.e., achievable potential is only assumed to be constrained by non-financial market barriers (e.g., product availability, delivery infrastructure limits, split-incentives for renters versus owners).
  - Data is available to represent the quantity of EE and DR that can be reliably obtained at a range of costs, in the form of measures or groups of measures with similar characteristics (e.g., load shapes, levelized cost, and deployment constraints).

What is an efficiency supply curve?

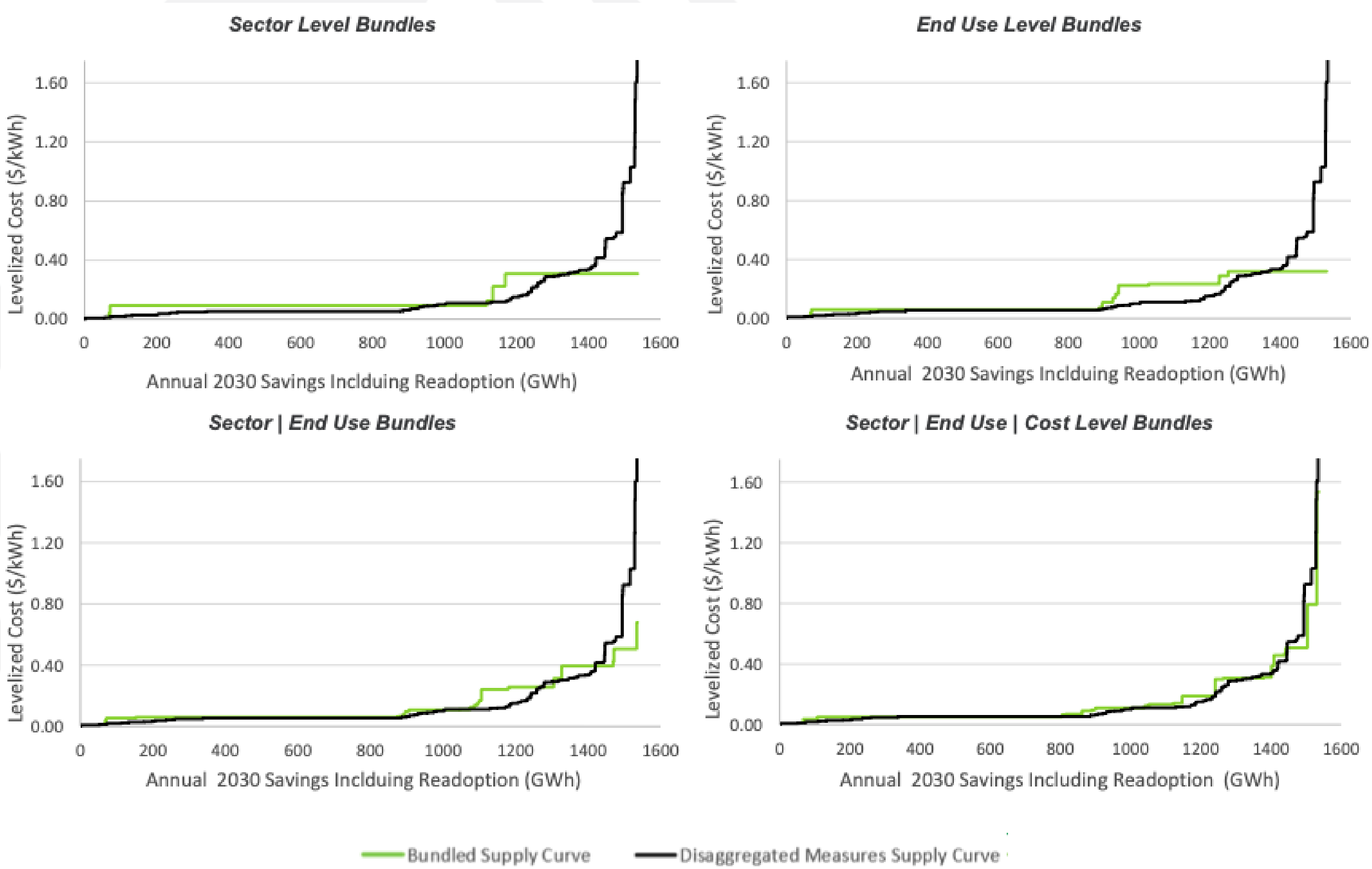
- EE potential is comprised of hundreds of measures.
- IRP models cannot simulate individual efficiency measures, so they are grouped together.
- Supply curves for EE (and other DERs) are usually represented as the amount of resource potential available in discrete “bundles” or “bins.”
- The next slides discuss *some* data inputs used to develop supply curves, but there is much more information available in our report.



Source: [NWPC Draft 8th Plan]

[Methods to Incorporate Energy Efficiency in Electricity System Planning and Markets]

California EE bundling approaches



Source: [Navigant]

Georgia Power EE bundling approaches

Commercial Load Shape-Based Bundles

Bundle Number	Number of Measures	Total Potential (MWh)	Weighted Avg. Levelized Cost ($/MWh)	Mean Levelized Cost ($/MWh)	Range of Levelized Cost ($/MWh)
21	2	21	0	0	$0-$0
11	2	8	0	0	$0-$0
14	1	1	0	0	$0-$0
4	343	87,593	16	17	$0-$43
19	323	32,363	18	18	$0-$49
2	160	97,414	20	19	$0-$43
9	157	12,452	22	30	$0-$73
13	183	30,355	54	57	$36-$87
10	34	2,700	59	39	$18-$128
18	3	46	78	56	$0-$167
0	150	76,169	78	74	$48-$130
16	89	10,862	118	117	$75-$167
3	107	31,497	122	121	$89-$160
20	1	0	195	195	$195-$195
15	23	376	200	228	$142-$361
5	101	43,549	205	197	$159-$240
8	95	55,907	212	200	$139-$231
17	47	5,139	246	223	$173-$277
1	112	10,863	272	270	$243-$326
12	42	7,142	309	332	$286-$387
7	42	7,781	378	376	$330-$461
6	47	6,234	432	442	$387-$497

Commercial Value Based Bundles

Bundle Number	Number of Measures	Total Potential (MWh)	Weighted Avg. Levelized Cost ($/MWh)	Mean Levelized Cost ($/MWh)	Range of Levelized Cost ($/MWh)
12	3	22	$0	$0	$0-$0
6	2	8	$0	$0	$0-$0
13	340	56,611	$7	$6	$0-$14
1	446	148,971	$20	$21	$14-$29
15	231	32,718	$36	$37	$29-$45
10	146	33,509	$55	$54	$46-$62
4	139	14,604	$70	$71	$63-$80
19	82	56,404	$87	$90	$81-$101
14	85	20,333	$111	$112	$103-$122
0	52	12,239	$135	$135	$124-$146
11	53	11,535	$159	$159	$147-$173
8	109	13,847	$192	$192	$176-$202
3	78	78,154	$214	$212	$202-$222
18	49	5,731	$238	$236	$225-$250
7	93	9,620	$265	$264	$250-$277
17	35	7,287	$295	$297	$282-$315
2	25	3,364	$333	$334	$318-$350
16	44	6,102	$376	$372	$353-$388
9	17	3,697	$402	$407	$391-$430
5	35	3,716	$457	$459	$436-$497

Commercial Cost Based Bundles

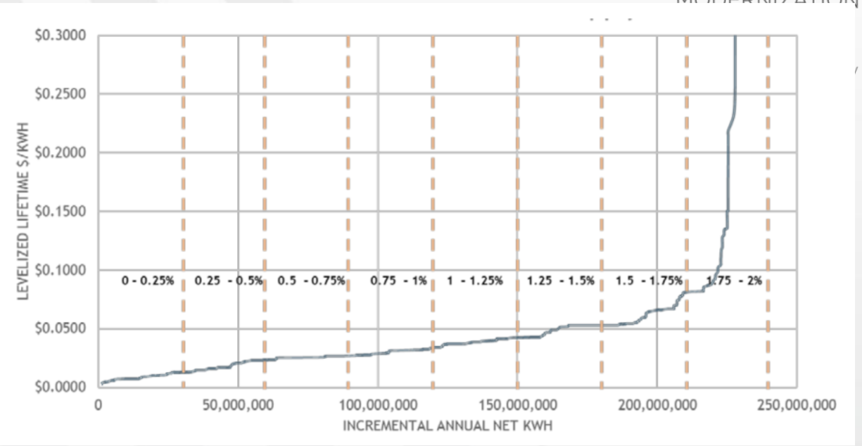
Bundle Number	Number of Measures	Total Potential (MWh)	Weighted Avg. Levelized Cost ($/MWh)	Mean Levelized Cost ($/MWh)	Range of Levelized Cost ($/MWh)
8	344	56,631	7	6	$0-$13
2	453	149,882	20	21	$14-$29
14	225	31,817	36	37	$29-$45
5	146	33,509	55	54	$46-$62
6	139	14,604	70	71	$63-$80
13	89	58,291	87	91	$81-$104
0	110	25,676	117	118	$106-$136
10	73	16,545	153	154	$136-$173
4	128	17,543	194	194	$176-$207
11	93	78,377	215	220	$208-$240
1	110	11,631	263	262	$241-$283
9	46	8,854	301	305	$285-$331
3	52	5,956	365	364	$336-$383
12	20	5,358	396	402	$385-$422
7	36	3,799	456	458	$430-$497

Source: [Georgia Power]

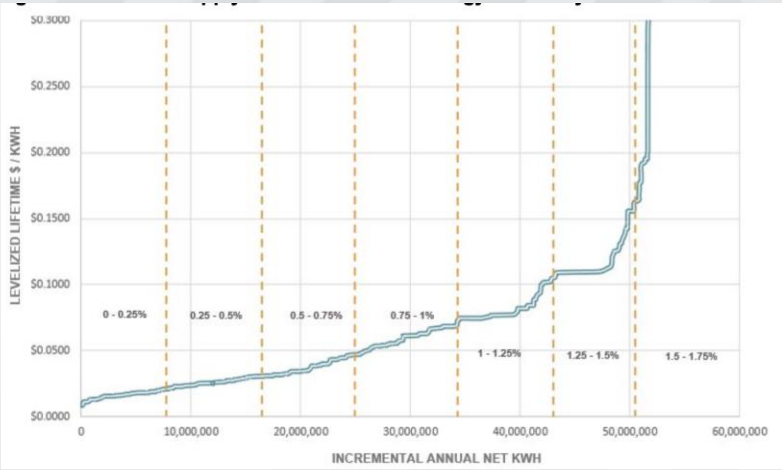
Indiana utilities EE bundling approaches

Bundle 1	Measures with a utility incentive cost ranging from $.00 to $.01 per lifetime kWh saved
Bundle 2	Measures with a utility incentive cost ranging from $.011 to $.05 per lifetime kWh saved
Bundle 3	Measures with a utility incentive cost over $.05 per lifetime kWh saved

NIPSCO 2018



IPL/AES 2019



Vectren 2019

"Bundles segmented by time periods:

- 2021-2023 representing the current portfolio plus potential study and low income
- 2024-2026 to align with next portfolio (all Residential and Non-Residential except Low Income)
- 2027-2034 (8 years)
- 2035-2042 (8 years)

Bundle levelized cost per MWh calculated using cots and energy savings impact for the full life of each measures."

Duke 2020

I&M 2018-2019 IRP EE bundles

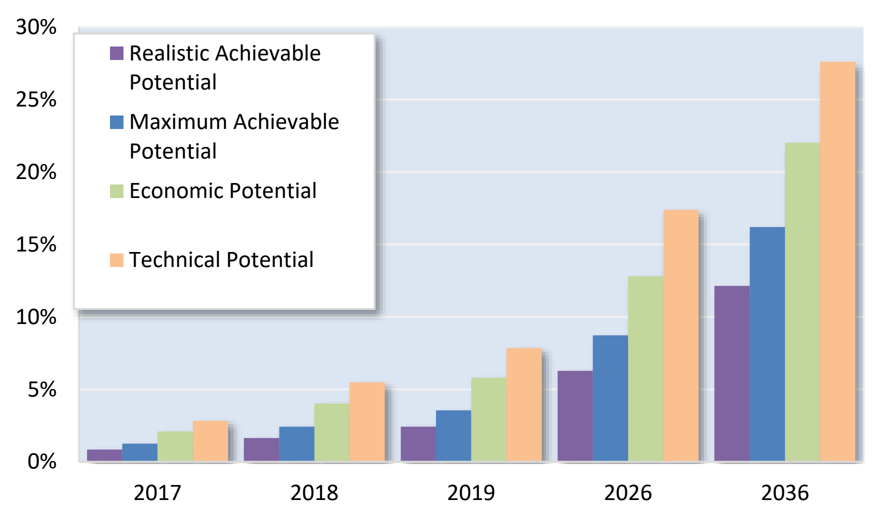


Table 7. Commercial Top Measures from Market Potential Study[12]

Rank	Commercial Measure	2019 Realistic Achievable Cumulative Savings (MWh)	% of Total
1	Interior Lighting – LED Screw-in Lamps	38,341	21.7%
2	Interior Lighting - LED High-Bay Fixtures	17,291	9.8%
3	Interior Lighting - Occupancy Sensors	14,131	8.0%
4	Interior Lighting - Linear Lighting	10,192	5.8%
5	Retrocommissioning	9,326	5.3%
6	Exterior Lighting - LED Area Lighting	7,938	4.5%
7	Water Heating - Water Heater EF 2.0 - Heat Pump	6,247	3.5%
8	Cooling - Water-Cooled Chiller - COP 9.77 (0.36 kW/TR)	6,113	3.5%
9	Interior Fluorescent - Delamp and Install Reflectors	4,731	2.7%
10	Exterior Lighting - LED Screw-in Lamps	4,704	2.7%
11	Ventilation - Ventilation	4,586	2.6%
12	Office Equipment - Desktop Computer	4,568	2.6%
13	Chiller - Chilled Water Reset	4,340	2.5%
14	HVAC - Economizer	4,334	2.4%
15	Office Equipment - Server	4,019	2.3%
16	Cooling - Air-Cooled Chiller - COP 4.40 (EER 15.0)	3,907	2.2%
17	Ventilation - Demand Controlled	2,861	1.6%
18	Ventilation - Variable Speed Control	2,330	1.3%
19	RTU - Advanced Controls	2,111	1.2%
20	Refrigeration - High Efficiency Compressor	1,849	1.0%
	Total Top Measures	**153,922**	**87.0%**
	Total Cumulative savings in 2019	**176,999**	**100%**

Table 6. Residential Top Measures from Market Potential Study

Rank	Residential Measure	2019 Cumulative Energy Savings (MWh)	% of Total
1	Interior Lighting - LED Screw-In Lamps	71,419	42.5%
2	Exterior Lighting - LED Screw-in Lamps	29,857	17.8%
3	Thermostat - WIFI	17,324	10.3%
4	Interior Lighting - Exempted LED Screw-In Lamp[11]	17,242	10.3%
5	Refrigerator - Decommissioning and Recycling	6,201	3.7%
6	Water Heating - Water Heater - ES 2.0 Heat Pump	4,595	2.7%
7	Freezer - Decommisioning and Recycling	3,851	2.3%
8	Windows - High Efficiency	2,065	1.2%
9	Windows - Install Reflective Film	1,509	0.9%
10	Appliances - Air Purifier – ENERGY STAR	1,462	0.9%
11	Water Heater - Temperature Setback	1,061	0.6%
12	Cooling - Central AC – SEER 14	995	0.6%
13	Central AC - Maintenance	988	0.6%
14	Whole-House Fan - Installation	887	0.5%
15	Water Heater - Low-Flow Showerheads	815	0.5%
16	Water Heater - Pipe Insulation	775	0.5%
17	Appliances – Refrigerator – CEE TIER 1	696	0.4%
18	Insulation - Ceiling	693	0.4%
19	Appliances – Dehumidifier – ENERGY STAR	611	0.4%
20	Electronics - Personal Computers	553	0.3%
	Total Top Measures	**163,598**	**97.4%**
	Total Cumulative savings in 2019	**168,038**	**100%**

Source: I&M

Xcel 2019-2020 IRP EE and DR bundles

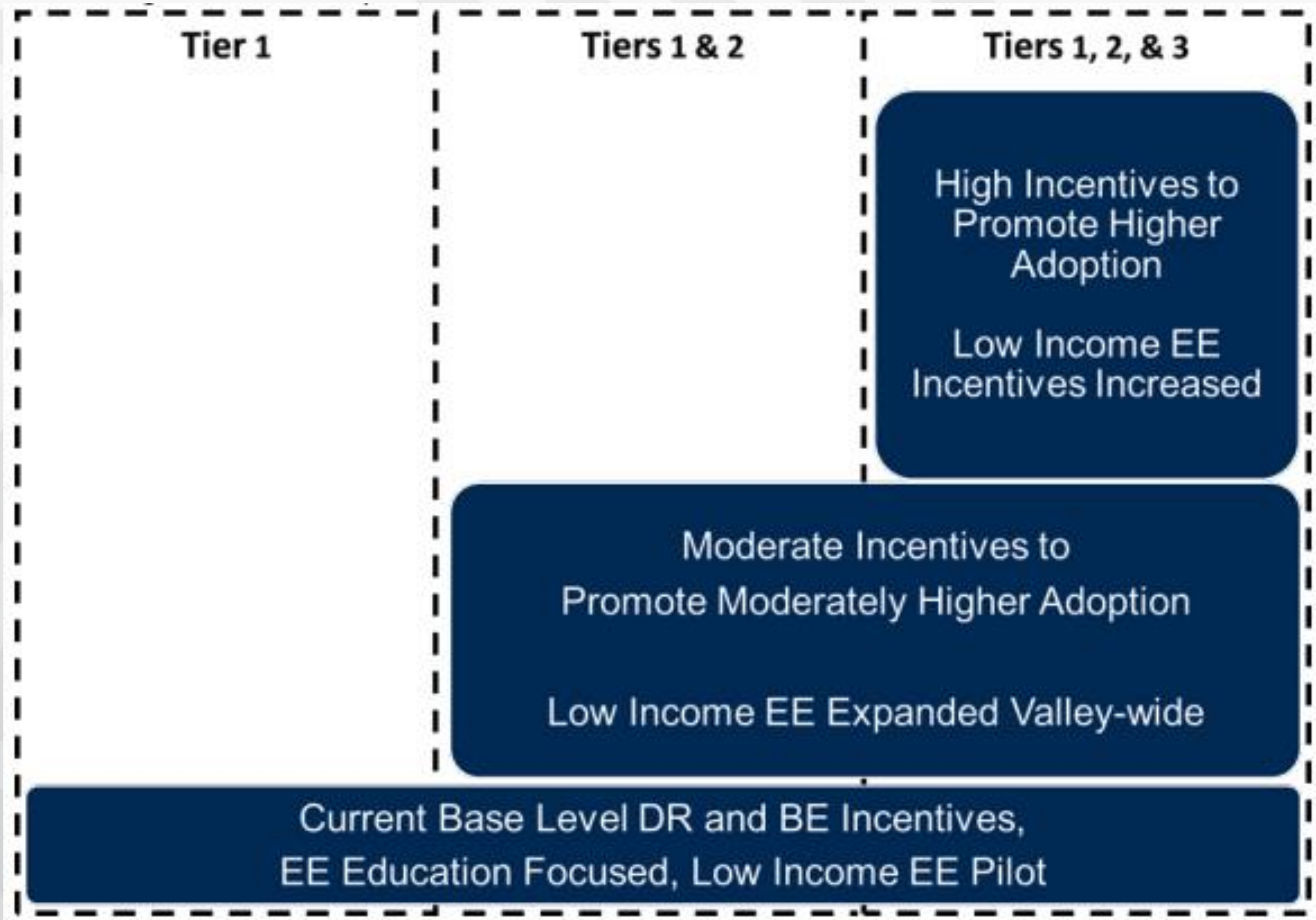
- Xcel created three EE and DR bundles
- Efficiency
  - Developed by Xcel based on optimal demand reduction
  - Program and Maximum are based on the EE potential study
- Demand response
  - Existing DR included in load forecast
  - DR bundles sized based on “supply curve thresholds”
  - First bundle forced into model because of Commission directive to procure 400 MW of DR

EE Bundle Name	2020 MWh	Price ($000)
Program	621	100,989
Optimal	43	12,598
Maximum	231	148,331

DR Bundle #	2020 – 2034 MW	Price ($000)
1	270-542	14,380 – 38,224
2	107-242	7,659 – 22,911
3	89 – 112	11,311 – 18,984

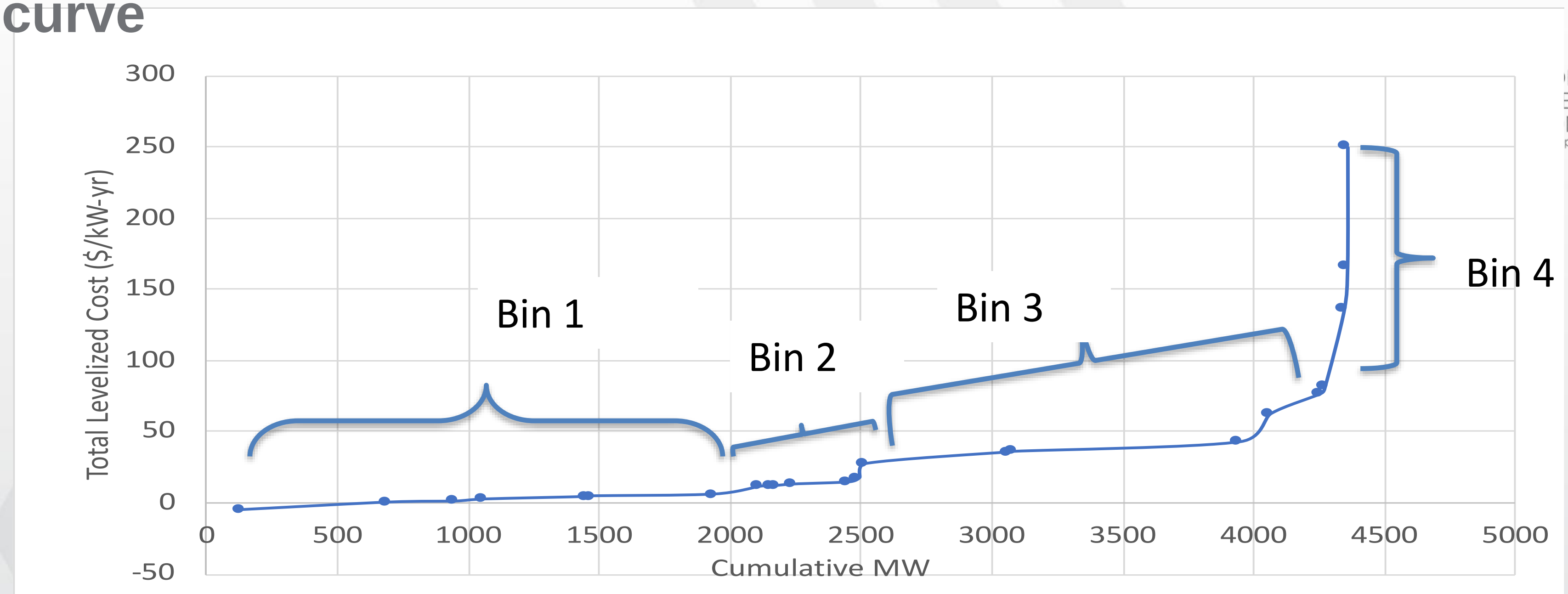
TVA EE, DR and beneficial electrification (BE) tiers

TVA efficiency, demand response and beneficial electrification tiers



Tennessee Valley Authority (TVA) 2019 IRP

Northwest Power and Conservation Council DR supply curve



Bin	Construction Costs ($/kW-yr)	Fixed O&M Costs ($/kW-yr)	Variable O&M ($/kW-yr)	Total Levelized Cost ($/kW-yr)	Total Potential (MW)
Bin 1	4.08	(1.98)	150.00	2.13	1937
Bin 2	12.32	0.69	150.00	13.09	554
Bin 3	22.59	18.69	150.00	41.30	1571
Bin 4	66.80	28.90	150.00	95.87	295

Source: NWPCC

PacifiCorp EE bundling approaches

Energy Efficiency Bundling Background

- In the past, energy efficiency measures have been grouped into 27 bundles per state by levelized cost of energy. Sample data (not final Conservation Potential Assessment) is used throughout this section:

Levelized Volume (aMW), by Levelized Cost of Energy ($/MWH) *Bundles not selected* **Cost Bundles Selected in 2019 IRP Pref. Port.**

	$1000-9999	$750-1000	$500-750	$400-500	$300-400	$250-300	$200-250	$190-200	$180-190	$170-180	$160-170	$150-160	$140-150	$130-140
CA	1	0	0	0	0	0	1	0	0.0	0	0	0	0	0
ID	4	1	0	0	1	1	1	0	0	0	0	0	0	1
WA	3	1	2	2	2	2	2	1	1	0	1	2	1	0
WY	2	1	1	0	1	1	2	0	0	0	1	0	1	0

	$120-130	$110-120	$100-110	$90-100	$80-90	$70-80	$60-70	$50-60	$40-50	$30-40	$20-30	$10-20	up to $10
CA	0	0	0	0	0	0	0	1	0	0	0	0	0
ID	0	0	0	1	1	1	1	1	1	2	1	1	5
WA	1	2	1	1	1	5	2	3	3	3	3	4	9
WY	1	2	1	5	1	1	2	4	4	3	7	10	38

Breaking out lots of high cost bundles doesn't add modeling value if none of them get picked.

Bundle sizing in $10/MWh increments leaves lots bundles with small volumes between $100-$200/MWh.

Breaking out lots of low cost bundles doesn't add modeling value if they always get picked.

- Conclusion: there are more bundles than are necessary for modeling levelized cost of energy.
- Is there another metric we can use to differentiate measures with desirable characteristics?

30 POWERING YOUR GREATNESS

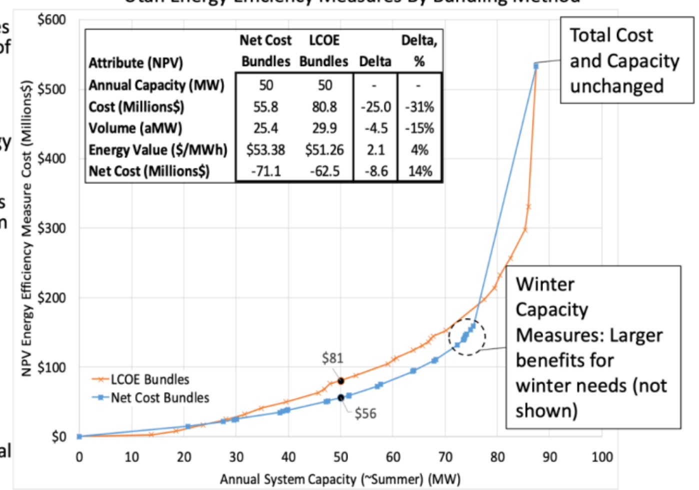
PacifiCorp [October 2020]

Energy Efficiency: Why Rebundle?

- Utah EE measures provide 50 MW of capacity at 31% lower cost after rebundling.
- Rebundled energy volume is lower, but estimated value per MWh is higher at medium gas / medium GHG power prices.
- Net cost of rebundled EE is $8.6M lower.
- Targeting winter or weather measures could provide additional value.

Utah Energy Efficiency Measures By Bundling Method

Attribute (NPV)	Net Cost Bundles	LCOE Bundles	Delta	Delta, %
Annual Capacity (MW)	50	50	-	-
Cost (Millions$)	55.8	80.8	-25.0	-31%
Volume (aMW)	25.4	29.9	-4.5	-15%
Energy Value ($/MWh)	$53.38	$51.26	2.1	4%
Net Cost (Millions$)	-71.1	-62.5	-8.6	14%



- 50 MW capacity is representative, model will select volumes and timing of each bundle.

26 POWERING YOUR GREATNESS

[PacifiCorp January 2021]

Capacity expansion models

- Capacity expansion models test alternative resource mixes and development timing (e.g., resource strategies) against a range of future conditions (e.g., load growth, natural gas prices, emissions costs or limits, or both).
- These models identify the “least cost” resource strategy <u>and may or may not</u> account for “risk.”
- Capacity expansion models do NOT determine:
  - Acceptable level of “cost”
  - Acceptable level of “risk”
  - Which resource strategy is “preferred”

Considerations for using direct competition of EE and DR

- Capacity expansion models require decision rules that determine when a resource is acquired.
  - Resources are always "developed" to meet reliability standards.
  - Resources are considered for development if they meet specified economic conditions.
  - The conditions that determine if EE or DR are selected should be comparable to generating resources.

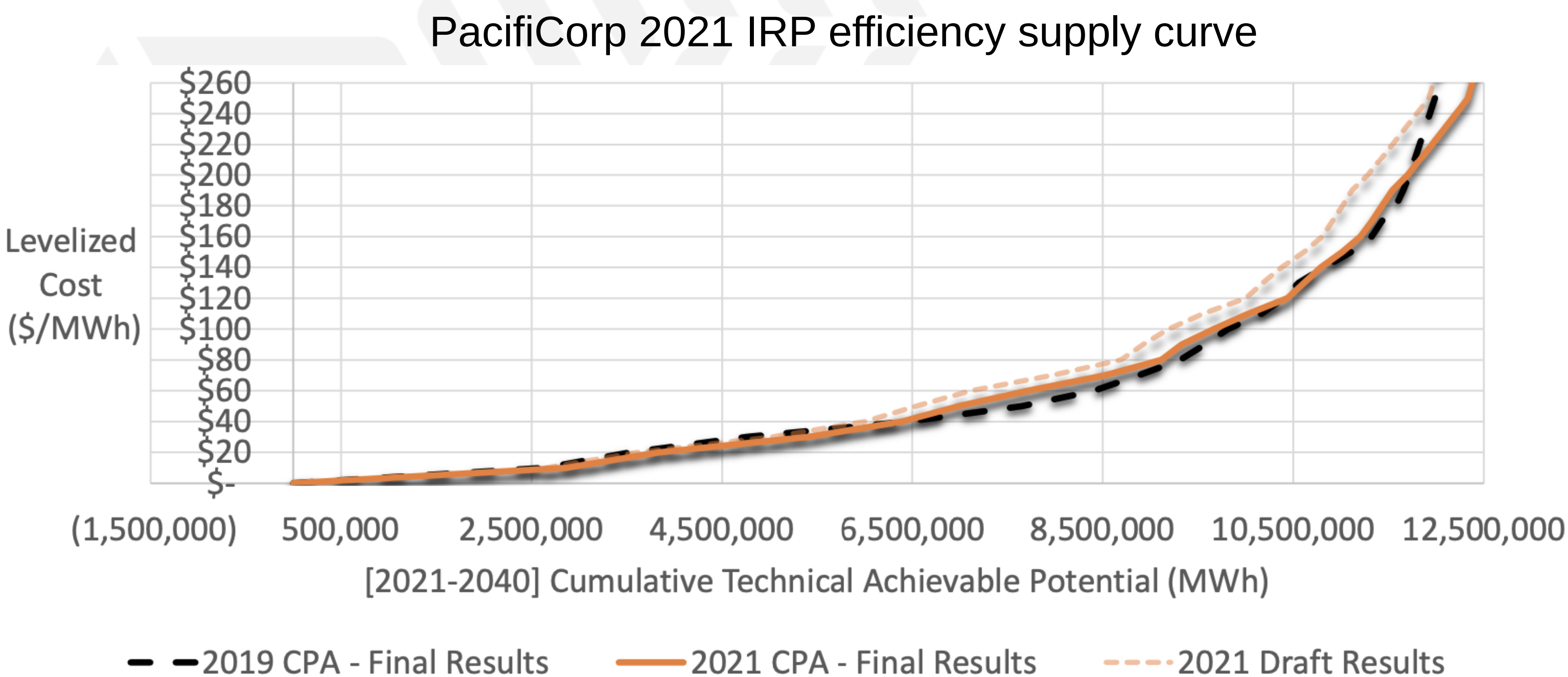
	SUPPLY SIDE COMPARISON			
	DR	EE	BE	Conventional Resource*
Year Available	2020	2020	2020	2023+
Outage Rate				✓
Heat Rate				✓
CO2 Emissions				✓
Fuel Costs				✓
Fuel Escalation				✓
O&M Costs	✓	✓	✓	✓
O&M Escalation	✓	✓	✓	✓
Capital Costs				✓
Capital Escalation				✓
Transmission Contingency Cost				✓
Project Contingency Cost				✓
Capacity Factor	✓	✓	✓	✓
Technology Shifts	✓	✓	✓	

*Conventional Resources could include nuclear, coal, gas, hydro, etc.

Tennessee Valley Authority (TVA) 2019 IRP

Potential modifications to acquisition logic in capacity expansion planning models (1)

- Unlike supply side resources, EE and DR can be acquired across a wide range of costs (i.e., EE has a nearly continuous supply curve).



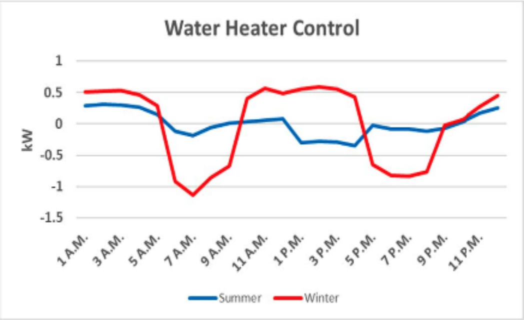
Source: PacifiCorp Conservation Potential Assessment

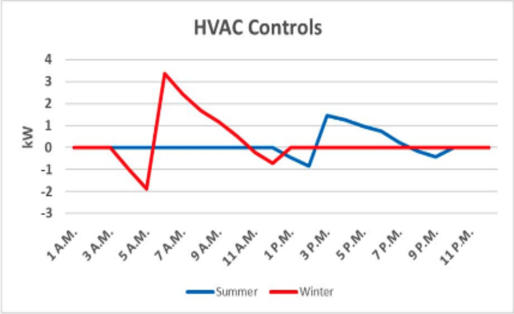
Potential modifications to acquisition logic in capacity expansion planning models (2)

- Maximum Retrofit Pace Constraint
  – Resource optimization models will "build" all retrofit EE and other DERs with a cost below the marginal dispatch cost of existing generating resources at first opportunity – unless constrained.
  – Real-world infrastructure limits for maximum annual retrofit development constraints on the annual acquisition of retrofit EE and DERs must be set in the model. Limits may be grow through time or be fixed for 20 years (i.e., assumes delivery infrastructure never expands).

2019 IRP Programs – Residential DR

- Hypothetical water heater control program modeled (top graph)
- Hypothetical HVAC control program included as a selectable option (lower graph)





Residential DR	Water Heater	HVAC Controls
Max Cumulative Installations	100,000	400,000
Annual Incentive Cost/Unit	$50	$60
Upfront Equipment Cost/Unit	$120	$45
Annual Incentive Cost	$5,000,000	$24,000,000

INTEGRATED Resource Plan 2019 | 116 TVA

PacifiCorp DR bundling results

Table 7.8 – Demand Response Program Attributes East Control Area[11]

Product	Summer		Winter	
	20-Year Potential (MW)	Levelized Cost ($/kW-yr)	20-Year Potential (MW)	Levelized Cost ($/kW-yr)
Res - EV DLC	210	$62	210	$62
Res - Home Energy Management System	1	$971	1	$1,020
Res – HVAC DLC	42	$94	63	$192
Res – Pool Pump DLC	0.3	$585	0.3	$585
Res – Water Heater DLC	2	$142	6	$63
Res – Grid Interactive Water Heaters	16	$288	54	$124
Res –Battery DLC	210	$62	210	$62
C&I –Battery DLC	92	$61	92	$61
C&I – Grid Interactive Water Heaters	7	$201	12	$140
C&I – HVAC DLC	4	$313	9	$355
C&I – Pool Pump DLC	0	$247	0	$225
C&I – Smart Thermostats	9	$50	5	$177
C&I – Water Heater DLC	1	$92	1	$65
C&I – Third Party	146	$217	117	$304
Ag – Irrigation DLC	13	$65	0	$0

Average levelized cost weighted by the 20-year cumulative potential in each state

Idaho Power EE bundling results

Table 5.1 Technical achievable bundles size and average cost

Bundle	5-Year Potential (aMW) 2019	2023	2028	2033	2038	20 Year Net Average Real Cost ($/MWh)
0–10th Percentile	1	7	17	27	33	-$102
10–20th Percentile	3	8	17	27	33	-$18
20–30th Percentile	3	12	22	29	34	$14
30–40th Percentile	1	8	18	27	33	$32
40–50th Percentile	2	8	16	25	34	$38
50–60th Percentile	1	7	14	22	33	$48
60–70th Percentile	2	11	21	28	33	$69
70–80th Percentile	3	16	27	32	34	$131
80–90th Percentile	2	13	26	31	34	$133
90–100th Percentile	2	11	24	30	33	$189
High Cost	2	14	27	35	41	$2,235

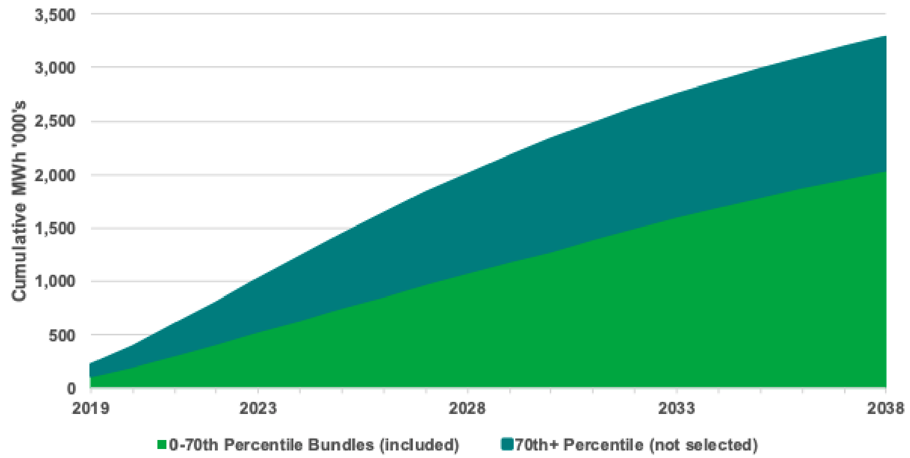
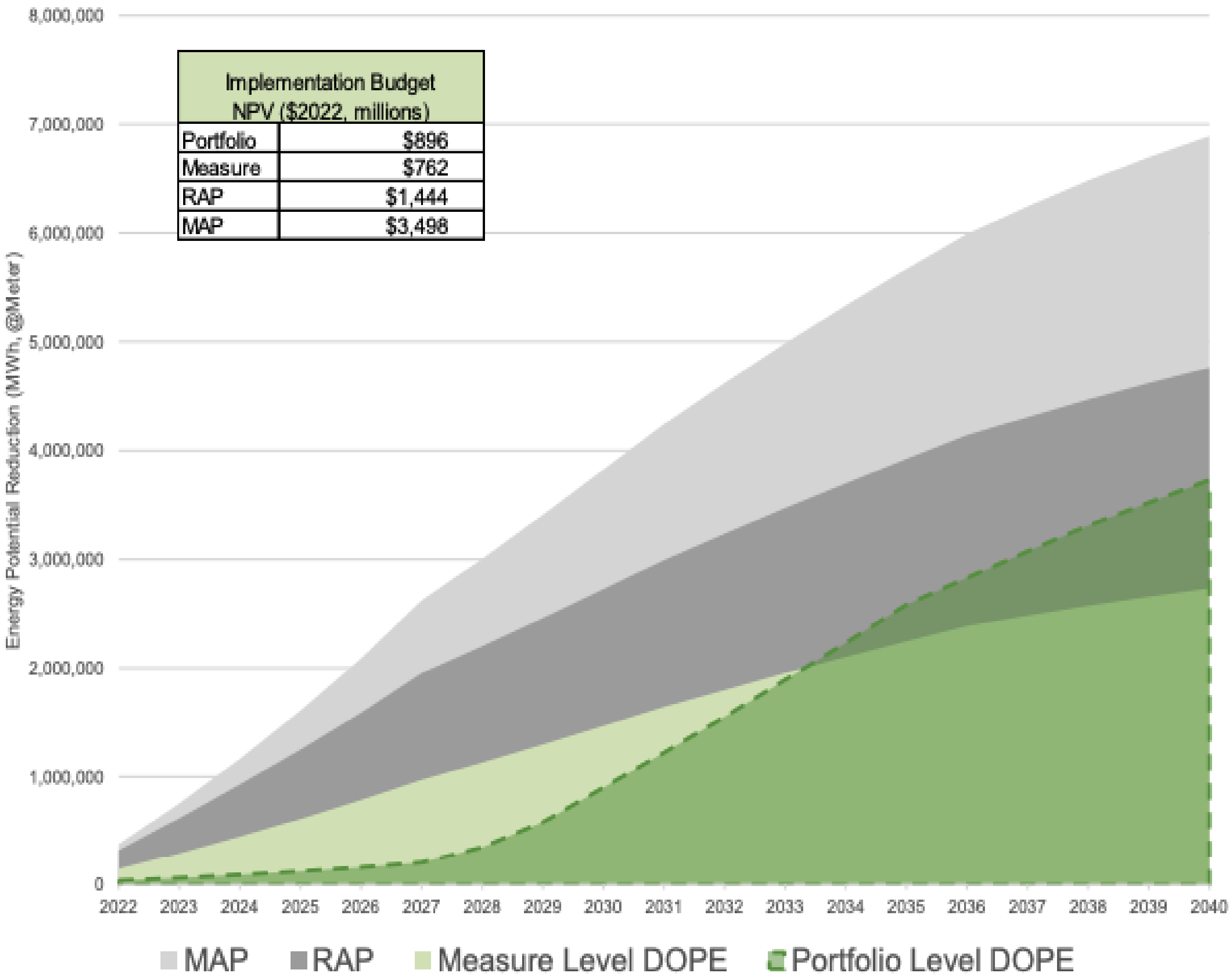


Figure 5.1 Energy-efficient bundles selected by the IRP model and bundles that were not economically competitive and were not selected for the 2019 IRP portfolios

Source: Idaho Power 2019 IRP

Ameren Missouri DSM bundling results



Implementation Budget NPV ($2022, millions)	
Portfolio	$896
Measure	$762
RAP	$1,444
MAP	$3,498

MAP = maximum achievable potential
RAP = realistic achievable potential
DOPE = dynamically optimized portfolio efficiency

DSM includes EE, DR, combined heat and power and distributed generation.

Source: Ameren IRP

Demand flexibility: Primary factors affecting the value of integrated DERs

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- Demand flexibility, for the residential and commercial sectors, is the capability of DERs to adjust building load profiles across different timescales.
- There is no single economic value of demand flexibility for utility systems.
- The value of a single “unit” (e.g., kW, kWh) of grid service provided by demand flexibility is a function of:
  - the *timing* of the impact (temporal load profile),
  - the *location* in the interconnected grid,
  - the *grid services* provided,
  - the *expected service life* (persistence) of the impact, and
  - the *avoided cost of the least-expensive resource alternative* providing comparable grid service.
- Demand flexibility valuation methods and practices should account for these variations.

Demand flexibility value = avoided cost

- The primary task required to determine the value of demand flexibility based on avoided cost is to *identify the alternative (i.e., "avoided") resource* and *establish its cost*.
- Methods used to establish avoided cost vary widely across the United States due to differences in:
  - electricity market structure
  - available resource options and their costs
  - state energy policies and regulatory context
- Traditionally, the economic value of energy efficiency and demand response (and other DERs) has been determined using the "avoided cost" of conventional resources that provide the identical utility system service.
- The underlying economic principle of this approach is that the *value* of a resource can be estimated using the *cost of acquiring the next least expensive alternative resource* that provides comparable services (i.e., the *avoided cost* of that resource).

Primary valuation task

- The primary task required to determine the value of demand flexibility based on avoided cost is to *identify the alternative (i.e., "avoided") resource* and *establish its cost*.

*See "Market Structure Influences Value of Demand Flexibility," "Resource Availability and Cost Vary Across U.S.," and "State Energy Policies and Regulatory Context" in Extra Slides.

Primary methods for valuing energy efficiency and other DERs*

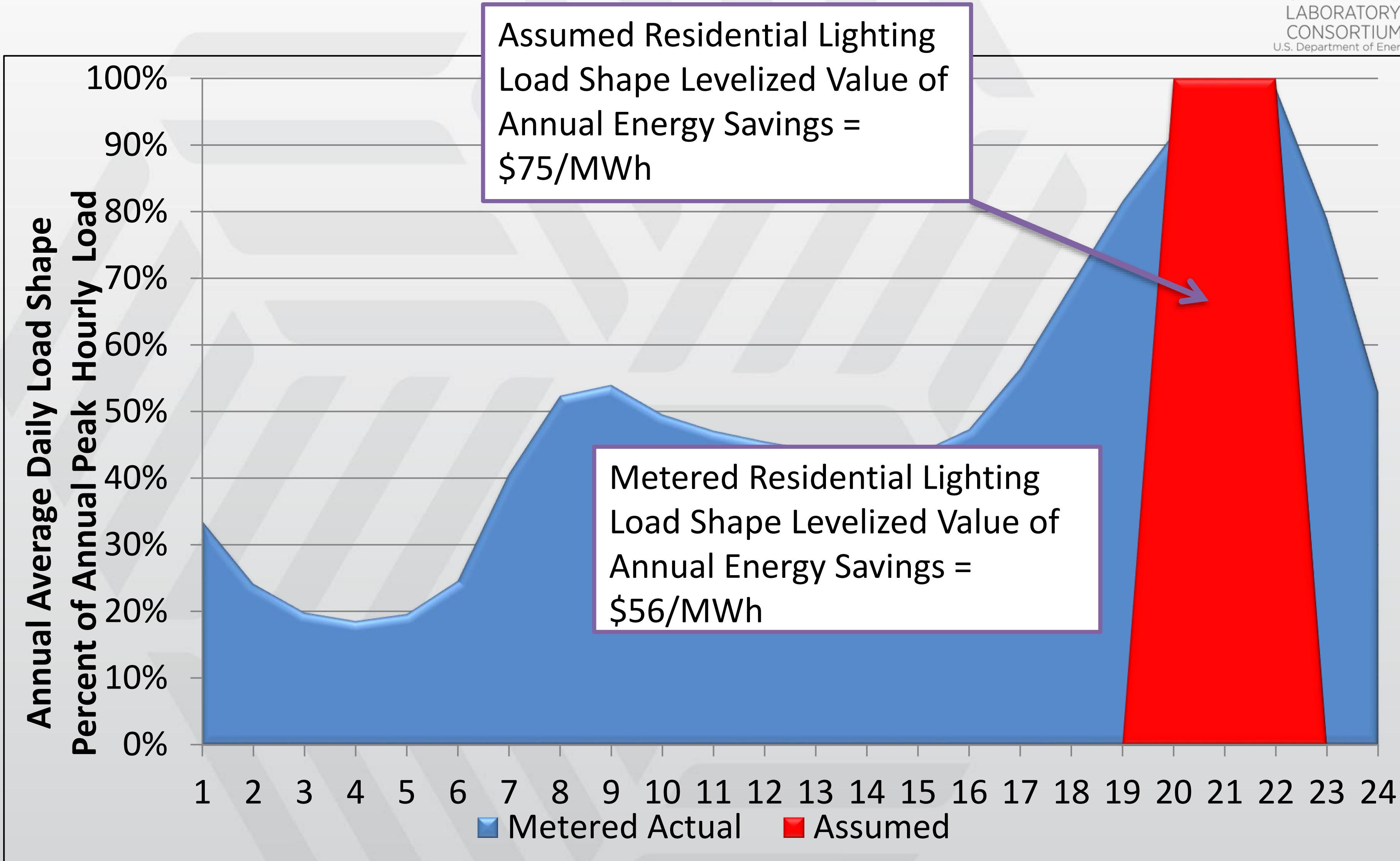
- **System capacity expansion and market models**
  - *Most prevalent practice* – Reducing the growth rate of energy and/or peak demand in load forecasts input into the model, then let it optimize the type, amount, and schedule of new conventional resources (generation, transmission or distribution)
  - *Less prevalent practice* - Directly competing DERs with conventional resources in the model to determine DERs' impact on existing system loads, load growth, and load shape—and thus dispatch of existing resources—and the type, amount, and timing of conventional resource development
- **Competitive bidding processes/auctions:** Use "market mechanisms" to select new DERs, currently limited to energy efficiency (EE) and demand response (DR)
- **Proxy resources:** Use the cost of a resource that provides grid services (e.g., a new natural gas-fired simple-cycle combustion turbine to provide peaking capacity) to establish the cost-effectiveness of DERs (i.e., determine the amount to develop) that provide these same grid services
- **Administrative/public policy determinations**: Use legislative or regulatory processes to establish development goals (e.g., Renewable Portfolio Standards and Energy Efficiency Resource Standards)

**Also used for utility-scale resource options analysis*

Some example of current gaps and limitations

- ❑ Not using *accurate load shapes* to determine time-varying value
- ❑ Not accounting for *distribution and transmission system capacity impacts*
- ❑ Not accounting for variations in *interactions between DERs*
- ❑ Not accounting for variations in *interactions between DERs and existing and future utility system resources*

Using inaccurate load shapes impacts evaluation of DERs as resource options — both energy and peak impacts.



Measure shape: [Residential and Commercial End-Use Load Profiles]

New load shapes available **THIS MONTH**

Register for the webinar [here]

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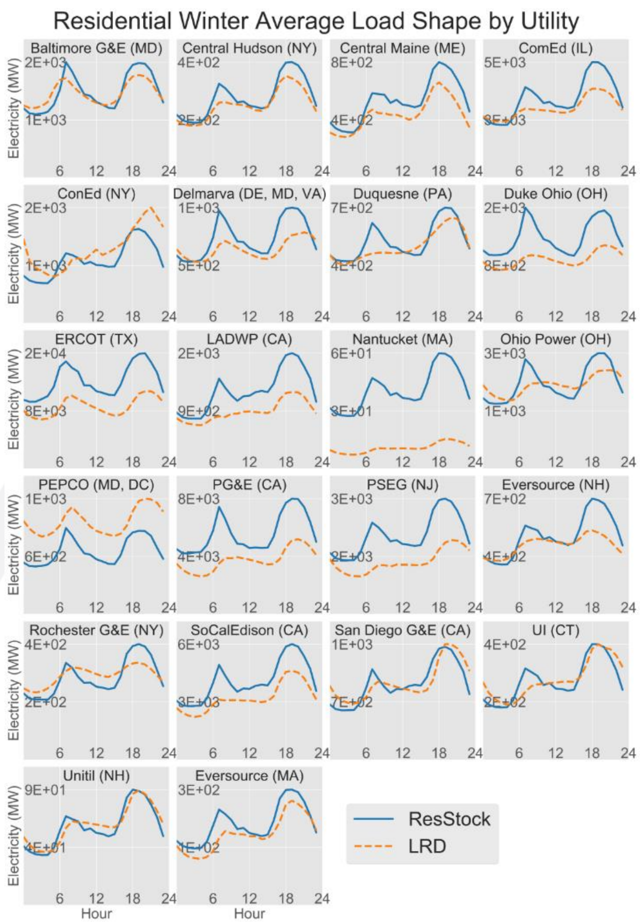
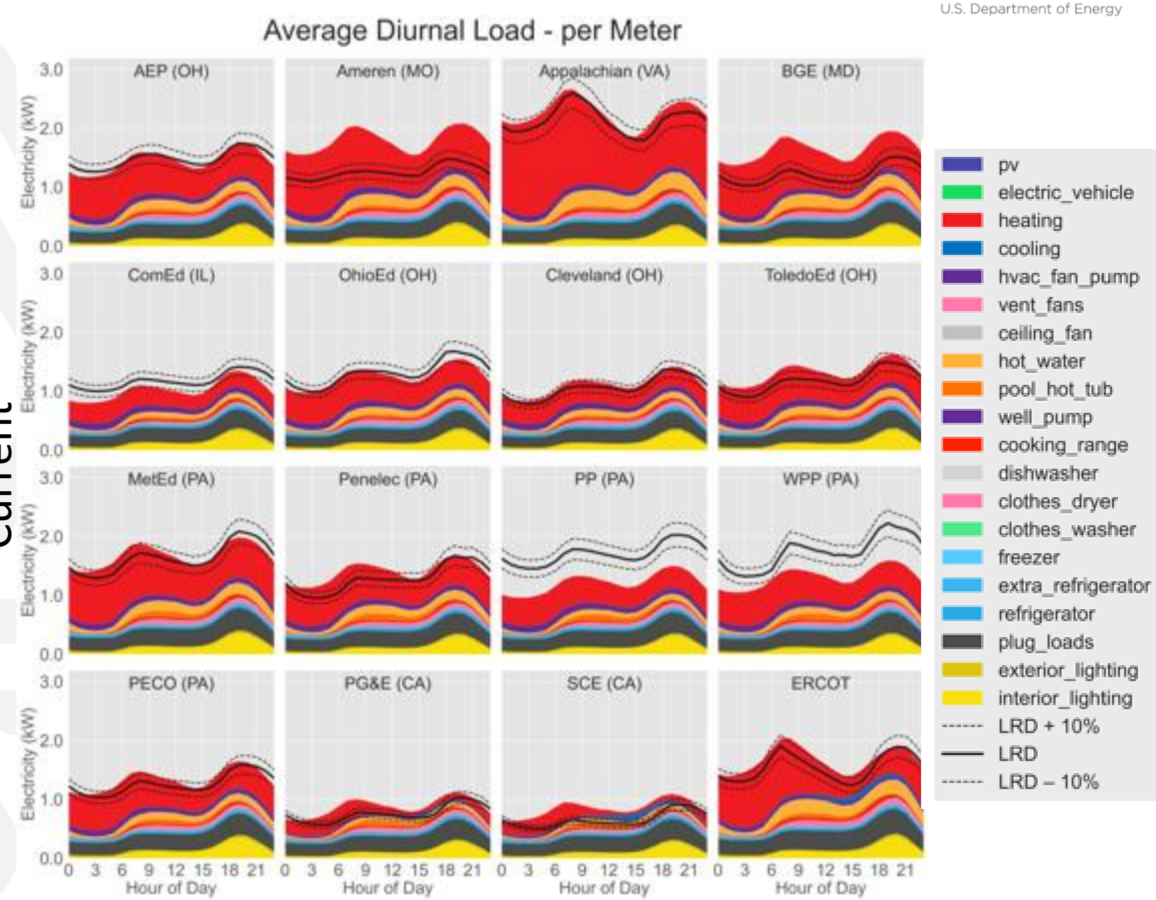
Before End Use Load Profiles Project

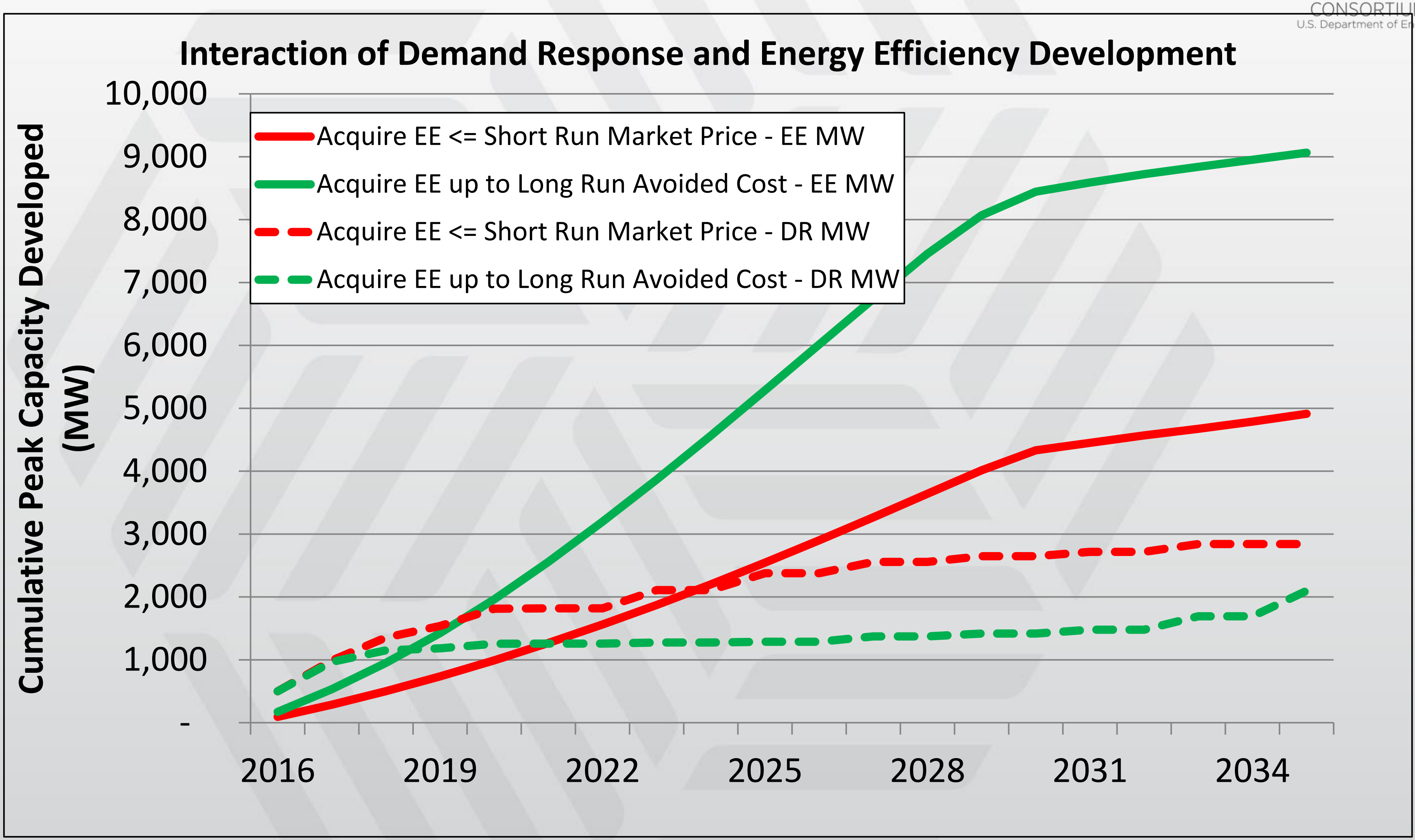


Current



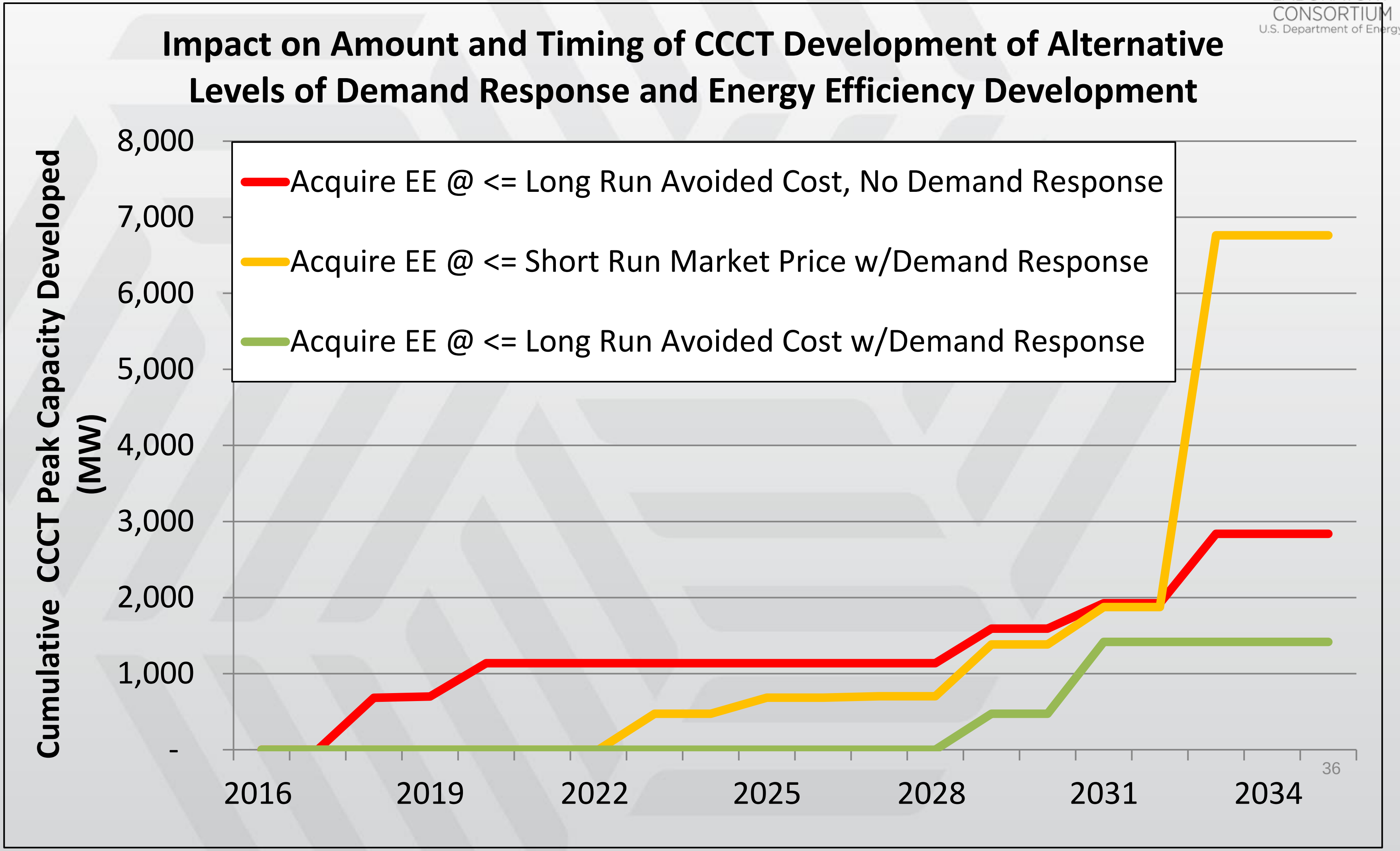
Source: Elaina Present IEPEC

Treating EE and DR as selectable resources in a capacity expansion model permits optimization *between these resources*



Source: Northwest Power and Conservation Council, 7th Power Plan

Treating EE and DR as selectable resource options in a capacity expansion model permits optimization *across supply side and demand side resources*



Source: Northwest Power and Conservation Council, [7th Power Plan]

Enhanced Valuation Methods: Seven Considerations

1. Account for *all electric utility system economic impacts* resulting from energy efficiency and other DERs
2. Account for variations in value based on *when* savings from energy efficiency and other DERs occurs
3. Account for the *impact of distribution system* savings on transmission and generation system value
4. Account for variations in value specific *locations* on the grid
5. Account for variations in value due to *interactions between DERs* providing demand flexibility
6. Account for benefits across the *full expected useful lives* (EULs) of the resources
7. Account for variations in value due to *interactions between DERs and other system resources*

Conclusions

- Modeling EE, DR and other DERs as selectable resources allows for ***consideration of relative cost and risk*** across the broadest array of potential solutions.
- Changes in long term electricity system planning may be needed to model EE, DR and other DERs as selectable resources.
  - Remove EE from the load forecast, except for stock turnover, known codes and standards and efficiency procurement requirements.
  - Use resource potential assessments to identify the technical achievable potential and inform development of EE, DR and other DER supply curves.
  - Appropriately value DERs when developing supply curves for capacity expansion models.
  - Create EE and DR bundles that have smaller cost ranges around the inflexion point for the electricity system cost.
  - Allow the capacity expansion model to compete all resources together to identify the timing and quantity of cost-effective DERs.
  - Modify the capacity expansion acquisition logic to enable the development of demand side resources.

Questions states can ask

- How are utilities in your state modeling EE, DR and other DERs today?
- What state policy or regulatory changes are needed to facilitate consideration of EE, DR and other DERs as selectable resources in electricity planning?
- What gaps can be filled to advance demand flexibility?
  - Can state programs (e.g., lead by example, energy-saving performance contracting) be modified to include demand flexibility?
  - Are utilities considering demand flexibility in their demand-side management portfolios?
  - How are utilities valuing demand flexibility?
  - What performance metrics are utilities using to measure demand flexibility?
  - Are existing utility incentive programs sufficient to advance demand flexibility?
  - Do current rate designs encourage consumers to align their consumption with electricity grid needs?

NASEO-NARUC Grid-Interactive Efficient Buildings Working Group

- Supported by U.S. DOE Building Technologies Office
- Inform states about GEB technologies and applications
- Identify opportunities and impediments
- Identify and express state priorities, concerns, interests
- Recognize temporal and locational value of EE and other DERs
- Enhance energy system reliability, resilience, and affordability

Inform state planning, policy, regulations, and programs

More information here. Additional states (public utility commissions and state energy offices) are welcome to join.

Resources for more information

U.S. Department of Energy. 2021. A Roadmap for Grid-interactive Efficient Buildings. Prepared by Andrew Satchwell, Ryan Hledik, Mary Ann Piette, Aditya Khandekar, Jessica Granderson, Natalie Mims Frick, Ahmad Faruqui, Long Lam, Stephanie Ross, Jesse Cohen, Kitty Wang, Daniela Urigwe, Dan Delurey, Monica Neukomm and David Nemtzow

Natalie Mims Frick, Tom Eckman, Greg Leventis, and Alan Sanstad. Methods to Incorporate Energy Efficiency in Electricity System Planning and Markets. January 2021

State and Local Energy Efficiency Action Network. 2020. Determining Utility System Value of Demand Flexibility from Grid-Interactive Efficient Buildings. Prepared by: Tom Eckman, Lisa Schwartz, and Greg Leventis, Lawrence Berkeley National Laboratory. https://emp.lbl.gov/publications/determining-utility-system-value

Natalie Mims Frick, Snuller Price, Lisa Schwartz, Nichole Hanus, and Ben Shapiro. *Locational Value of Distributed Energy Resources*

Natalie Mims Frick, Juan Pablo Carvallo and Lisa Schwartz. Quantifying reliability and resilience impacts of energy efficiency: Examples and opportunities (forthcoming)

Natalie Mims Frick, Juan Pablo Carvallo and Margaret Pigman. Time-sensitive Value of Efficiency Calculator (forthcoming)

Berkeley Lab's research on time- and locational-sensitive value of DERs

Fredrich Kahrl, Andrew D Mills, Luke Lavin, Nancy Ryan, Arne Olsen, and Lisa Schwartz (ed.). The Future of Electricity Resource Planning. 2016. Berkeley Lab's Future Electric Utility Regulation report series.

Berkeley Lab and NREL's End Use Load Profiles for the U.S. Building Stock project

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Background Slides

Applicability of Enhanced Valuation Methods to Distribution, Generation, and Transmission Planning Analyses

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Enhanced valuation methods to account for:	Distribution System Planning			Generation Planning		Transmission Planning	
	Hosting Capacity (for distributed generation capacity)	Energy Analysis (loss estimation)	Thermal Capacity (peak capacity)	Capacity Expansion Modeling	Market-Based Mechanisms	Capacity Expansion Modeling	Congestion Pricing Analysis
1. All electric utility system economic impacts resulting from demand flexibility	●	●	●	●	●	●	●
2. Variations in value based on when demand flexibility occurs	●	●	●	●	●	●	●
3. Impact of distribution system savings on transmission and generation system value	◔	●	◑	◑	◑	◑	◑
4. Variations in value at specific locations on the grid	●	●	◔	◔	◔	●	●
5. Variations in value due to interactions between DERs providing demand flexibility	●	◕	●	◕	◕	◕	◕
6. Benefits across the full expected useful lives of the resources	◑	◑	●	◑	◑	●	●
7. Variations in value due to interactions between DERs and other system resources	◕	◑	●	●	●	●	●

● most applicable, ◔ least applicable

Grid-interactive Efficient Buildings and Demand Flexibility

Grid-interactive Efficient Building	An energy-efficient building that uses smart technologies and on-site DERs to provide demand flexibility while co-optimizing for energy cost, grid services, and occupant needs and preferences in a continuous and integrated way	Demand Flexibility*	Capability of DERs to adjust a building's load profile across different timescales

DERs – Resources sited close to customers that can provide all or some of their immediate power needs and/or can be used by the utility system to either reduce demand or provide supply to satisfy the energy, capacity, or ancillary service needs of the grid

Smart technologies for energy management - Advanced controls, sensors, models, and analytics used to manage DERs. Grid-interactive efficient buildings are characterized by their use of these technologies.

**Also called "energy flexibility" or "load flexibility"*

Source: Neukomm et al. 2019. [Grid-interactive Efficient Buildings Technical Report Series: Overview of Research Challenges and Gaps](). Also see example building in Extra Slides. More information [here]().

Demand-side Management Strategies to Manage Building Loads

- *Energy efficiency:* Ongoing reduction in energy use while providing the same or improved level of building function
- Demand flexibility:
  - *Load shed*: Ability to reduce electricity use for a short time period and typically on short notice.
  - *Load shift*: Ability to change the timing of electricity use. In some situations, a shift may lead to changing the amount of electricity that is consumed.
  - *Modulate*: Ability to balance power supply/demand or reactive power draw/supply autonomously (within seconds to subseconds) in response to a signal from the grid operator during the dispatch period
  - *Generate*: Ability to generate electricity for onsite consumption and even dispatch electricity to the grid in response to a signal from the grid

Source: Neukomm et al. 2019

Gaps and Limitations of Current Methods: Restructured Markets

- Not all DERs are eligible to participate in markets.
- Not all utility system DER benefits are reflected in the bulk power system. Not captured:
  - Locational value of avoided/deferred T&D capacity
  - Value of distribution system losses
  - Value of resilience
- "Long-term" resource value is not recognized in some markets.
  - For example, PJM limits compensation for EE and DR to four years, regardless of measure life, assuming that the impact of these resources will be embedded in its econometric forecast after that period.

Gaps and Limitations of Current Methods: Utilities in Vertically Integrated States

- Not all utilities (or state requirements) include all system benefits of DERs.
  - e.g., some include time-varying, locational, risk mitigation, and resilience value, while others do not
- Not all utilities (or state requirements) consistently quantify system benefits of DERs.
  - e.g., some use marginal distribution system losses to “gross up” impacts to generation and transmission system, while others use average system losses, and the accuracy of load shape data (if used) varies widely
- Resource options analysis often fails to account for the potential interaction between DERs (e.g., impact of EE on DR potential, impact of storage on distributed generation).
- Typical resource optimization modeling embeds DER impacts in the load forecast, so it fails to capture potential DER interactions with existing and future resources.
- Commercially available capacity expansion models have limited capability to model DERs as resource options (except perhaps DR and battery storage).

Summary of Valuation Enhancements and Implementation Guidance (1)

Valuation Enhancement	Guidance
1. Account for all electric utility system economic impacts resulting from demand flexibility	Prioritize enhancements for analyses used to derive the value of primary utility system benefits.
2. Account for variations in value based on when demand flexibility occurs	Develop and use hourly forecasts of avoided energy and capacity costs in combination with publicly available load shape data for DERs to value demand flexibility.
3. Account for the impact of distribution system savings on transmission and generation system value	Model and calculate distribution system-level impacts (i.e., locational impacts and associated economic value) first so that results can be used to adjust inputs to analysis of bulk transmission and generation system values.

Source: State and Local Energy Efficiency Action Network. 2020. Determining Utility System Value of Demand Flexibility from Grid-Interactive Efficient Buildings. Prepared by: Tom Eckman, Lisa Schwartz, and Greg Leventis, Lawrence Berkeley National Laboratory.

Summary of Valuation Enhancements and Implementation Guidance (2)

Valuation Enhancement	Guidance
4. Account for variations in value at specific locations on the grid	Initiate a distribution system planning process that includes: (1) hosting capacity analysis to estimate generating DER capacity limits and identifies demand flexibility that can mitigate limits, (2) thermal limit analysis to estimate locational value of non-wires solutions, (3) energy analysis to quantify marginal distribution system losses, and (4) systemwide analysis of the avoided cost of deferred distribution capacity expansion.
5. Account for variations in value due to interactions between DERs providing demand flexibility	Start accounting for interactions between DERs. Basic analysis can assume that deployment of multiple types of DERs does not impact the existing or future electric grid in a way that alters avoided costs. Such basic analysis does not require the use of system capacity expansion models.

Summary of Valuation Enhancements and Implementation Guidance (3)

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Valuation Enhancement	Guidance
6. Account for benefits across the full expected lives of the resources	As a first step, use the EUL of DERs providing demand flexibility to calculate their economic value. However, because demand flexibility is largely based on controls, the dispatch of which is determined by the combined impact of grid operators and owner/occupant responses, EULs may be more a function of rate and program design, compared to EULs for traditional energy efficiency measures. Uncertainty regarding EULs for demand flexibility may be best addressed through program design.
7. Account for variations in value due to interactions between DERs and other system resources	Use distribution, transmission and generation capacity expansion modeling, supplemented as necessary with other methods described in section 4 of this report, to determine the impact of widespread deployment of demand flexibility for grid services. Implementing this enhancement will require customization of commercially available capacity expansion models.

Implementation Resources (1)

Valuation Enhancement`	Implementation Resources
1. Account for all electric utility system economic impacts resulting from demand flexibility	• National Efficiency Screening Project, *National Standard Practice Manual* • EPRI, *The Integrated Grid - A Benefit-Cost Framework* • EPA, *Assessing the Multiple Benefits of Clean Energy – Resources for States* (particularly Section 3.2.4)
2. Account for the time-sensitive economic value of demand flexibility	• Berkeley Lab reports discuss data and methods required to capture temporal value of energy efficiency including *Time-Varying Value of Electric Energy Efficiency* and *Time-Varying Value of Energy Efficiency in Michigan*. More resources at https://emp.lbl.gov/projects/time-value-efficiency. • Smart Electric Power Alliance, *Beyond the Meter: Addressing the Locational Valuation Challenge for Distributed Energy Resources*
3**. Account for the impact of distribution system-level savings on transmission and generation system value**	• PNNL, *Electric Distribution System Planning with DERs – Tools and Methods (forthcoming)* • Smart Electric Power Alliance, *Beyond the Meter: Addressing the Locational Valuation Challenge for Distributed Energy Resources*

Source: State and Local Energy Efficiency Action Network. 2020. Determining Utility System Value of Demand Flexibility from Grid-Interactive Efficient Buildings. Prepared by: Tom Eckman, Lisa Schwartz, and Greg Leventis, Lawrence Berkeley National Laboratory.

Implementation Resources (2)

Valuation Enhancement	Implementation Resources
4. Account for the locational economic value of demand flexibility	• Smart Electric Power Alliance, *Beyond the Meter: Addressing the Locational Valuation Challenge for Distributed Energy Resources* • *Benefit-Cost Analysis Handbook* developed for New York's REV process • California's Locational Net Benefits Analysis Tool (and user's guide) • ConEd's *Benefit Cost Analysis Handbook* recognizes DER benefits for avoided distribution capacity infrastructure and provides methods to quantify location-specific marginal costs that the system defers or avoids by opting for non-wires solutions.
5. Account for interactions between DERs providing demand flexibility	• Frick et al., Berkeley Lab, *A Framework for Integrated Analysis of Distributed Energy Resources: Guide for States* EPRI, *The Integrated Grid - A Benefit-Cost Framework*
6. Account for potential variations in the timing and/or amount of the electric grid service provided by demand flexibility over the expected lives of the DERs	• EPRI, *The Integrated Grid - A Benefit-Cost Framework*
7. Account for interactions between DERs providing demand flexibility and existing and potential conventional grid resources supplying comparable services	• Berkeley Lab, *A Framework for Integrated Analysis of Distributed Energy Resources: Guide for States* • EPRI, *The Integrated Grid - A Benefit-Cost Framework*