Integrated Resource Plan

2016

Public Meeting #3

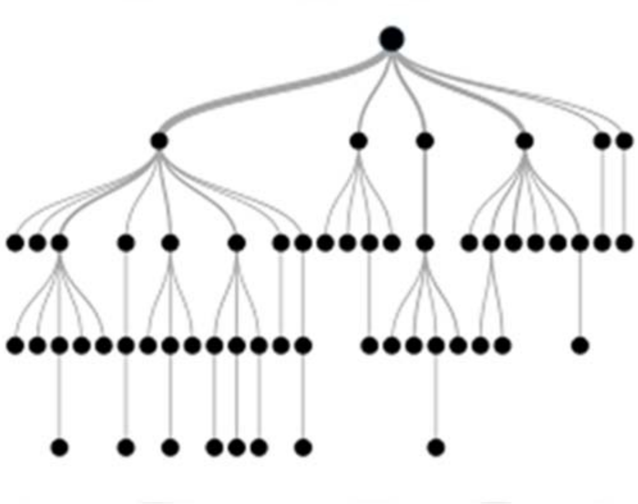
Thursday, August 13, 2015

Portland General Electric

Welcome: Meeting Logistics

- Local Participants:
  - DoubleTree facility

- Virtual Participants:
  - Ask questions via ‘chat’ or ‘raise hand’ feature
  - Meeting will stay open during breaks, but will be muted



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Welcome: Today's Topics

- Safety moment
- Public process
- Capacity update
- Flexibility update
- Demand Response update
- Load Forecast
- Natural Gas Forecast
- Portfolio and Future Ideation

Safety Moment: Concussions

<u>Determine if a person has a concussion</u>

1. Assess consciousness

2. Assess the person

3. Check for physical symptoms

4. Check for cognitive symptoms

5. Watch the person

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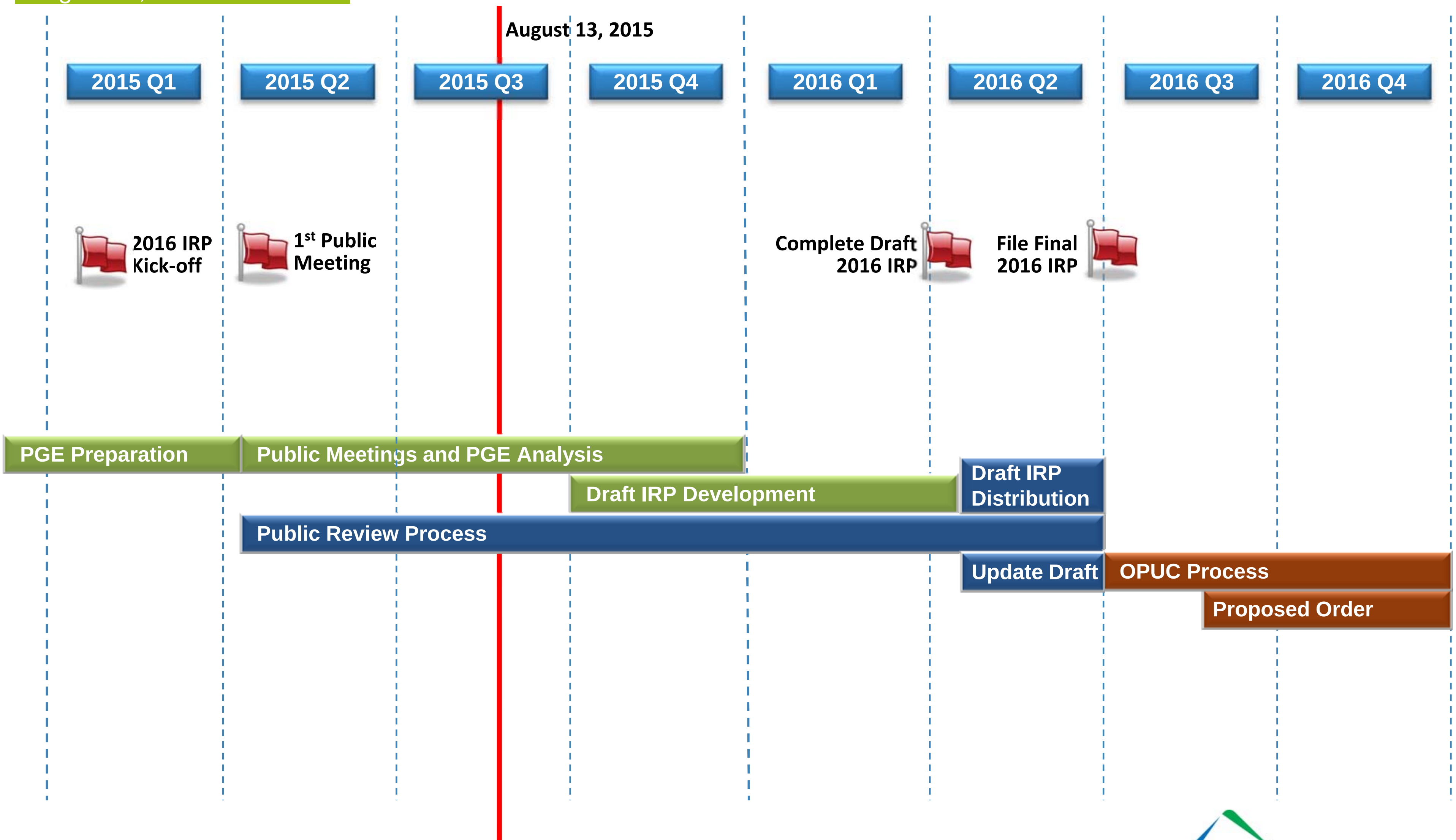
Public Process Update

2016 IRP Timeline

August 13, 2015 Slide 6



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2016 IRP: Meeting Schedule And Planned Topics

Q2/Q3 2015

April 2 — Meeting #1 Public
- Welcome
- Load Forecast Methodology
- Load/Resource Balance
- Environmental Policy

July 6 — Workshop #1 Commission (Salem)
- EIM Study Update
- 111(d) Representation

July 15 — Workshop #1 Technical
- Load Forecast Methodology Implementation
- Load Forecast Results

July 16 — Meeting #2 Public
- Load Forecast
- Energy Efficiency Forecast
- Supply-side Resource Assumptions
- Solar/Dist. Generation Study Presentation

Public Meeting

Technical Workshop

Technical Workshop with Commission Present

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2016 IRP: Meeting Schedule And Planned Topics

Q3 2015
(Tentative)

August 13

Meeting #3
Public

- *Development*
  - *Demand Response*
  - *Flexibility Study*
  - *Planning Reserve Margin*
  - *Portfolios and Futures Ideation*
- *Analysis*
  - *Load Forecast*
  - *Natural Gas Forecast*

September 25

Workshop #2
Technical

- *Development*
  - *111(d) Rule update*
  - *Climate Study review*
  - *CVR update*
  - *Portfolios and Futures*
- *Analysis*
  - *Portfolio Analytics Methodology*
  - *VER Integration Methodology*
- *Results*
  - *Planning Reserve Margin*
  - *Load Resource Balance*

October 5

Workshop #2
Commission (Salem)

- *Development*
  - *Portfolios and Futures Update*
  - *Colstrip Portfolio Representation*
- *Results*
  - *Planning Reserve Margin*
  - *Load Resource Balance*

Public Meeting

Technical Workshop

Technical Workshop with Commission Present

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2016 IRP: Meeting Schedule And Planned Topics

Q4 2015 (Tentative)

December 3

Workshop #3
Technical

- *Analysis*
  - *111(d) Demonstration*
  - *Portfolios and Futures*

December 4

Meeting #4
Public

- *Development*
- *Analysis*
  - *Portfolios and Futures*
  - *Transmission*
- *Results*

Date TBD

Workshop #3
Commission (Salem)

- *Results*
  - *EIM Study*

Public Meeting

Technical Workshop

Technical Workshop with Commission Present

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2016 IRP: Meeting Schedule And Planned Topics

Q1 2016 (Tentative)

February 10, 2016

Meeting #5 Public

- *Results*
  - *Colstrip Portfolios*
  - *Variable Resource Integration*
  - *Trigger Points*
  - *Preferred Portfolio*

Date TBD

Additional Workshops

- *As Required*

Date TBD

Additional Meetings

- *As Required*

Public Meeting

Technical Workshop

Technical Workshop with Commission Present

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Clean Power Plan: Preliminary takeaways

- Final rule focuses on fossil units; proposal focused on states.
- 2020 compliance date extended to 2022 – aligns with Boardman timing.
- Renewables count toward compliance if built after 2012.
- Hydro averaged over 1990-2012, instead of single 2012 year.
- Energy Efficiency no longer part of target, but still part of compliance.
- Oregon’s goal rises from 372 lbs/MWh to 871 lbs/MWh. Montana’s falls from 1771 lbs/MWh to 1305 lbs/MWh.
- Little certainty until state finalizes its plan.

Turn in State Plan
September 6, 2016

Final State Plans
September 8, 2018

2016 - 2018

Emission Credit Reduction
2020-2021

2019-2022

Compliance – Three multi-year step downs
2022 - 2030

2022 - 2030

PGE Summer Peak Load

- Portland area experienced extreme hot weather the week of July 27
- 103^{o}F high; four hours at or above 100^{o}F
- Demand response programs were called upon during this time – est. 26 MW reduction
- 3,965 MW – Net system peak (July 30, ~6pm)
- 3,949 MW – Prior net system summer peak (July 29, 2009 ~4p) with high of 106^{o}F
- PGE's all time system peak is 4,073 (December 21, 1998 HE19)

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2016 IRP: Status

Item	Status
Meetings	**6 Total (2 Complete, 4 Scheduled)**
Workshops	**4 Total (2 Complete, 2 Scheduled)**
Feedback Forms	**1 Received**
2013 IRP Action Plan	**5 Actions (OPUC Order No. 14-415)**
Supply Side	*In progress (Hydro contracts, portfolios, no major resources)*
Demand Side	*In progress (EE, DR, CVR)*
Enabling Studies	*In progress (Load forecast, Emerging EE, DG, EIM, Flexibility)*
Transmission	*In progress*
Other	*In progress (RPS, Clean Power Plan)*
Related Topics	*In progress [UM1713 (IEE); UM 1716 (VoS); UM 1719 (VER CC)]*
2016 IRP Development	**~13 Chapters**
Draft	*Not Started*
Final	*Not Started*

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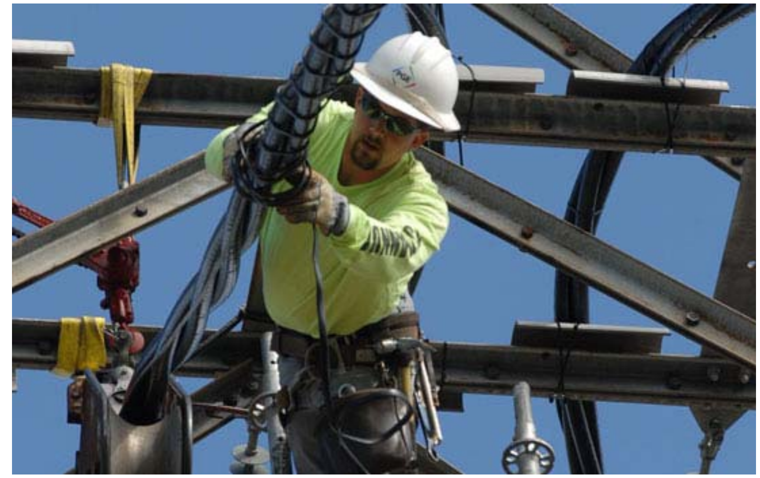

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Capacity and Flexibility Update

Capacity and Flexibility Update

- PGE's resource portfolio is undergoing significant changes
  - Loss of longstanding hydro and coal assets
  - Increasing penetration of variable renewable generation
  - Increasing need for resource flexibility
- PGE is seeking a rigorous method for evaluating the capacity contribution of renewable resources
  - OPUC docket UM 1719
- PGE needs a comprehensive framework for evaluating system reliability
  - Current PRM method relies on a heuristic
  - Difficult to measure contribution of variable renewable generation toward capacity needs under this approach
- Utilities need a rigorous method for assessing flexibility needs of alternative wind and solar portfolios

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Capacity and Flexibility Update

- PGE retained E3 to study capacity and flexibility needs of PGE's system under a range of future conditions considered in this IRP
- Calculate a Planning Reserve Margin that is sufficient to meet a 1-day-in-10 year reliability standard
- Provide reliability-based guidelines to ensure that PGE's system is resource adequate during both the summer and winter seasons
- Provide estimates of the contribution of renewable resources to PGE's capacity needs consistent with this reliability framework
  - Cumulative contribution of existing resources
  - Marginal contribution of potential new resources
- PGE will continue evaluating the results of this study for potential use in planning

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Capacity and Flexibility Needs under Higher Renewables

Portland General Electric IRP Public Meeting #3

August 13, 2015

Portland, Oregon

Arne Olson, Partner

Elaine Hart, Managing Consultant

Ana Mileva, Senior Consultant

E3's expertise has placed us at the nexus of planning, policy and markets

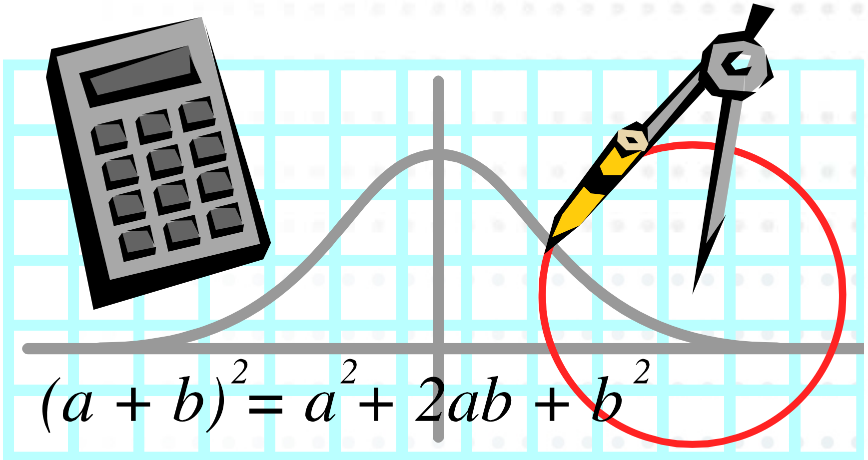
- San Francisco-based company with 40+ professionals
- Foremost North American consultancy in electricity sector economics, regulation, planning and technical analysis
- Consultant to many of the world's largest utilities and renewable developers
- Groundbreaking methods in capacity and flexibility assessment used by California agencies, CAISO, WECC, and many utilities and developers

Defining today's planning problem

- **Introduction of variable renewables has shifted the planning paradigm**
  - No longer sufficient to plan for adequate capacity
- **Today's planning problem consists of two related questions:**
  1. How many MW of <u>dispatchable</u> resources are needed to (a) meet load, and (b) meet flexibility requirements on various time scales?
  2. What is the optimal mix of new resources, given the makeup of the existing fleet of conventional and renewable resources?

Problem is stochastic in nature

- **Load is variable and uncertain**
  - Often characterized as "1-in-2" or "1-in-10"
  - Subject to forecast error



- **Renewable output is variable and uncertain**
- **Conventional generation can also be stochastic**
  - Hydro endowment varies from year to year
  - Generator forced outages are random
- **Need robust stochastic modeling to better approximate the size, probability and duration of any shortfalls**

E3 Approach

+ **E3 has developed stochastic planning techniques to estimate capacity and flexibility needs under high renewables within a consistent analytical framework**

  1. **RECAP:** Loss-of-Load Probability study completed first to ensure the system has sufficient "pure capacity" to meet a defined reliability standard. Also determines renewable resource capacity contribution.

  2. **REFLEX:** Stochastic production simulation study then estimates the value of flexible dispatch within a portfolio.

+ **Analysis captures a wide distribution of system conditions through Monte Carlo draws of operating days from many years of load, wind, solar and hydro conditions**

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Planning Reserve Margin Investigation Using E3's Renewable Energy Capacity Planning Model

Arne Olson, Partner

PGE currently utilizes a 12% PRM

+ **In the past, PGE has used a 12% planning reserve margin (PRM) for establishing resource adequacy:**

$$PRM = \frac{Reliable\ December\ Capacity\ (MW)}{1 - in - 2\ year\ Peak\ Load\ (MW)} - 1$$

- Standard is based on a heuristic: 6% for operating reserves + 3% for more extreme weather + 3% for forced outages
  - This approach was adequate when most resources were dispatchable
- PGE has a dual summer/winter peak, and in practice PGE uses two overlapping standards:
  - 12% PRM above summer peak, 12% PRM above winter peak
- In the 2013 IRP, PGE signaled its intent to review its PRM in the 2016 IRP cycle

Current method needs updating

+ **December reliable capacity method may no longer be appropriate given fast-growing summer peak**
+ **Current method does not lend itself well to developing a rigorous measure of the capacity contribution of dispatch-limited resources such as wind and solar**
  - Current method is a deterministic analysis that focuses only on a single hour: the highest load hour of the year
  - Wind and solar output is stochastic: high sometimes, low at other times
  - ***These factors will be increasingly important as the renewable portfolio grows!***

E3 investigated experience & methods in other jurisdictions

- **E3 investigated reliability criteria, planning reserve margins, and PRM accounting methodologies for several utilities**
  - Other utilities in the West and similarly-sized utilities throughout the country
- **High-level findings:**
  - No industry-standard method of determining acceptable reliability or PRM
  - No NERC or WECC requirements or standards
  - PRM accounting methodologies vary by utility
  - Planning Reserve Margins range from 12-20%

Planning criteria used by other utilities

	Peak Demand in 2021 (MW)	Planning Criterion	PRM	Peak Season
Puget Sound Energy	7,000 MW	LOLP: 5%*	16% (2023 - 2024)	Winter
Avista	Summer: 1,700 MW; Winter: 1,900 MW	LOLP: 5%*	22% (14% + operating reserves)	Both
PacifiCorp	10,876 MW	LOLE: 2.4 hrs/ year	13%	Summer
Arizona Public Service	9,071 MW	One Event in 10 Years	15%	Summer
Tucson Electric Power	2,696 MW	PRM	15%	Summer
Public Service Co. of New Mexico	2,100 MW	LOLE: 2.4 hrs/ year	Greater of 13% or 250 MW	Summer
El Paso Electric	2,000 MW	PRM	15%	Summer
Cleco	3,000 MW	LOLE = 1-day-in-10 yrs.	14.8%	Summer
Kansas City Power & Light	483 MW	Share of SPP**	12%**	Summer
Oklahoma Gas & Electric	5,500 MW	Share of SPP**	12%**	Summer
South Carolina Electric & Gas	5,400 MW	24 to 2.4 days/10 yrs	14-20%	Both
Tampa Electric	4,200 MW	PRM	20%	Both
Interstate Power & Light	3,300 MW	PRM	7.3%	Summer
Florida Power and Light	24,000 MW	PRM	20%	Both
California ISO	52,000 MW	LOLE: 0.6 hours/year	15-17%	Summer

* PSE and Avista use NWPCC criterion of 5% probability of shortfall occurring any time in a given year
** SPP uses 1-day-in-10 years or 12% PRM system-wide

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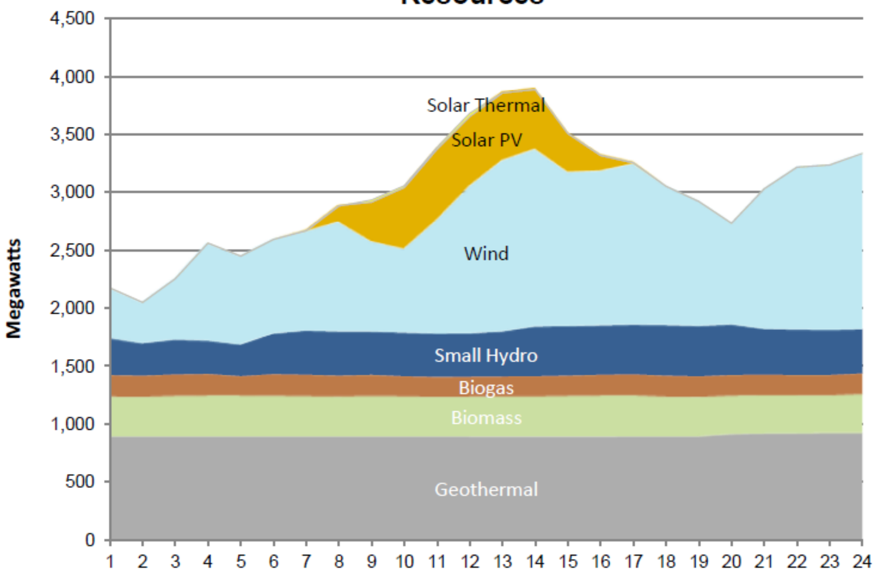
RECAP METHODOLOGY

E3's Renewable Energy Capacity Planning Model (RECAP)

- E3 has developed an open-source model for evaluating power system reliability and resource capacity value within high penetration renewable scenarios
- Based on extensive reliability modeling literature
- Used by a number of utilities and state agencies including CAISO, CPUC, CEC, SMUD, WECC, HECO, others

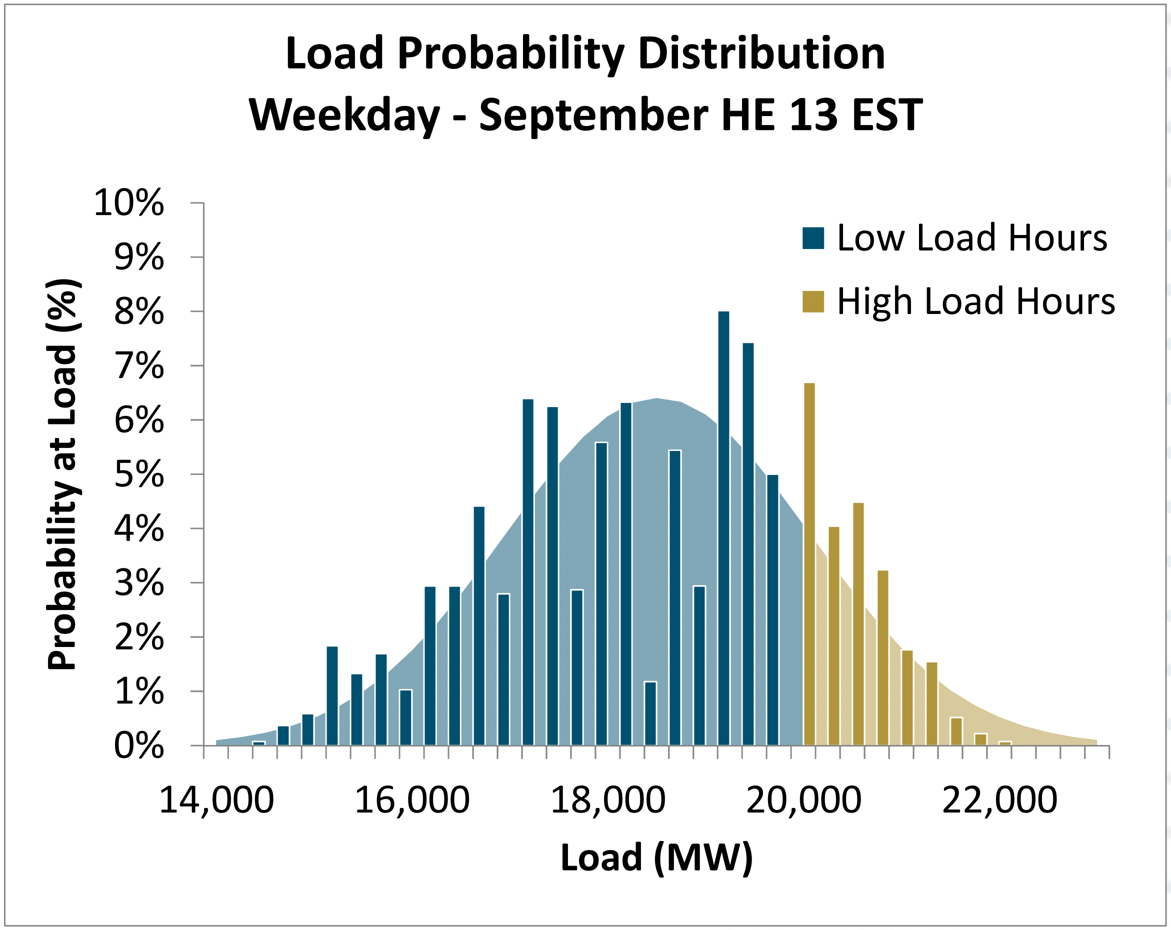


RECAP Model overview

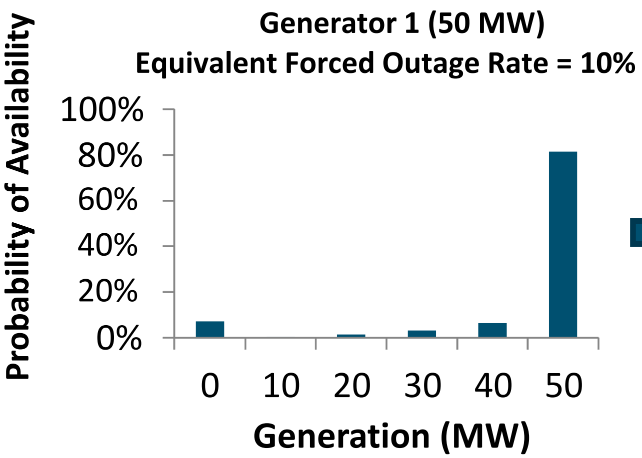
- **RECAP Model assesses reliability performance of a power system using the following metrics:**
  - **Loss of Load Probability (LOLP)**: probability of capacity shortfall in a given hour
  - **Loss of Load Expectation (LOLE)**: expected hours of capacity shortfall in a given year
  - **Expected Unserved Energy (EUE)**: expected load not met due to capacity shortfall during a given year
- **Four-step LOLE calculation:**
  - Step 1: calculate hourly net load distributions
  - Step 2: calculate outage probability table for dispatchable capacity
  - Step 3: calculate probability that supply < net load in each time period
  - Step 4: sum across all hours of simulated years

Step 1: Create load distributions

- Create probability distribution of hourly load for each <u>month / hour / weekday-weekend</u> combination (12x24x2=576 total distributions)
- Source data: simulated load shapes for 33 weather years based on 2007-2012 loads
- Load shapes scaled to match monthly and seasonal 1-in-2 peak and energy forecasts provided by PGE



Step 2: Calculate available dispatchable generation



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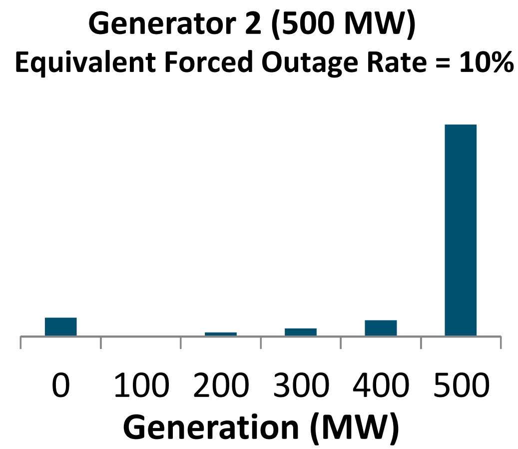

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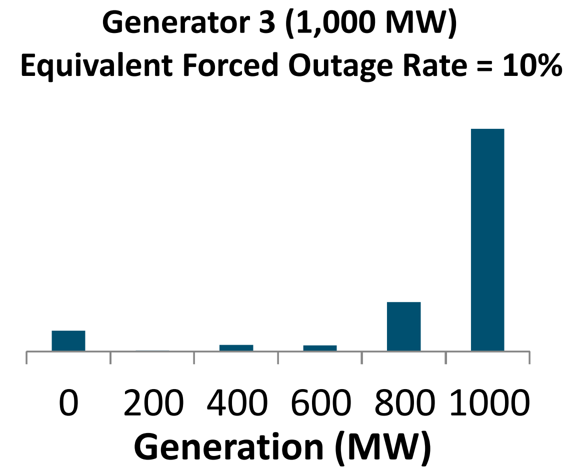

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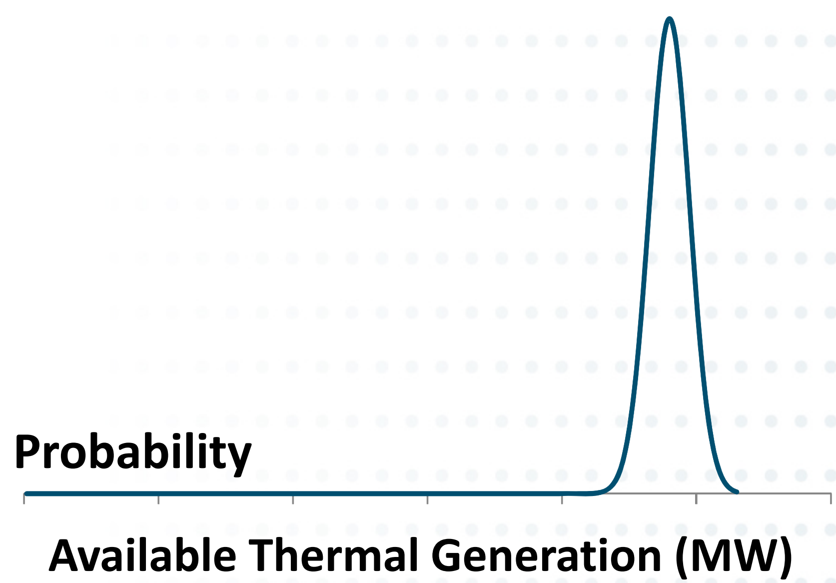
All other generators

for each month / hour / day-type

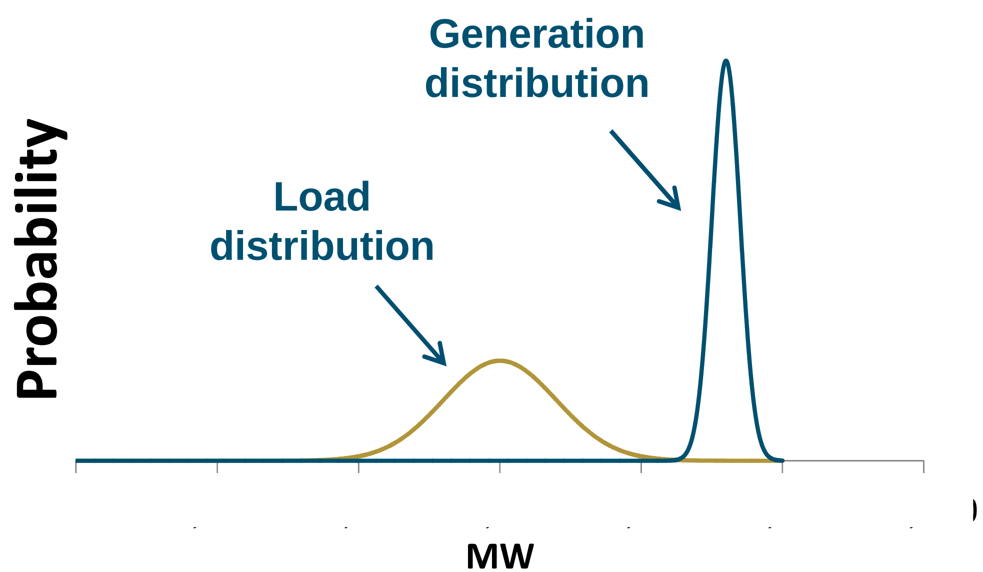
=

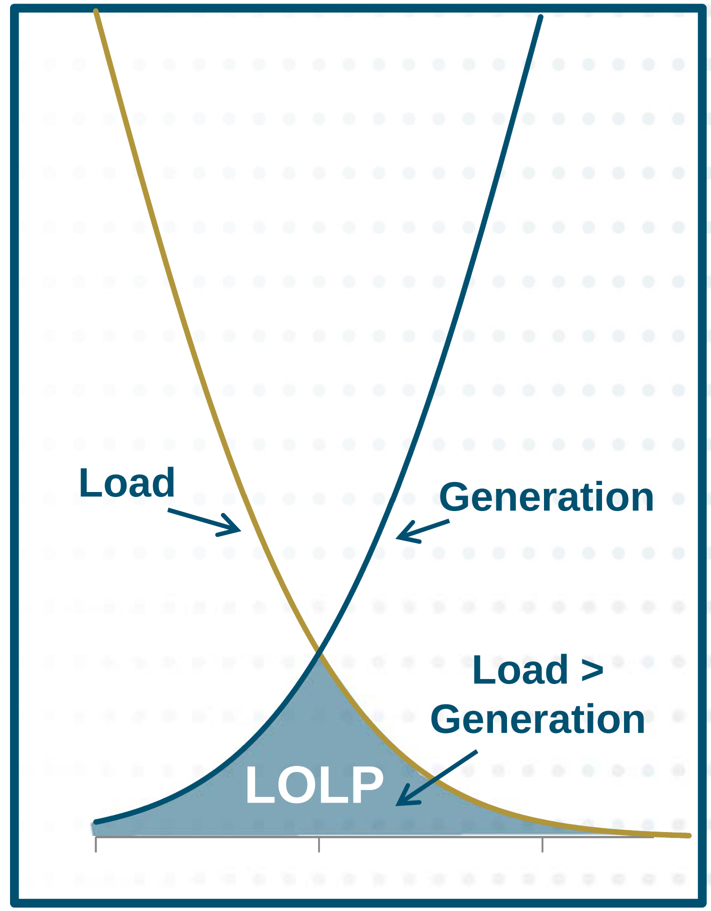


Step 3: Calculate LOLP

+ Combination of load and resource distributions determines Loss-of-Load Probability for a given hour

+ Load is most likely to exceed generation during hours with high load, high generator outages, or both





Step 4: Sum across all simulated years to get LOLE

- LOLP is the probability of lost load in a given hour. LOLE is the annualized sum of LOLP across all hours (h) and simulated years (n)

$$LOLE = Average_n\left(\sum_{h=1}^{8760} \boldsymbol{LOLP_h}\right)$$

- PGE has selected a LOLE standard of 24 hours in 10 years, or 2.4 hours/year
- PGE defines “loss of load” during a given hour as having available resources less than load plus 6% operating reserves
  - Regional emergency response may prevent actual load shedding even in the event of a shortfall

LOLE converted into Target PRM for planning and procurement

- **LOLE is an accurate estimate of a system's reliability, however it can be cumbersome to use directly in planning and procurement**
  - It is more convenient to convert result into a Target PRM to translate LOLE (hrs./yr.) into need (MW)
  - Target PRM defined as % increase above expected 1-in-2 peak load
- **PRM should be interpreted as calculating the need for *effective MW* of capacity**
  - PRM is not meant to be interpreted literally as MW available during *single peak hour*
  - PRM is a simplification of LOLE that can occur in *any hour*

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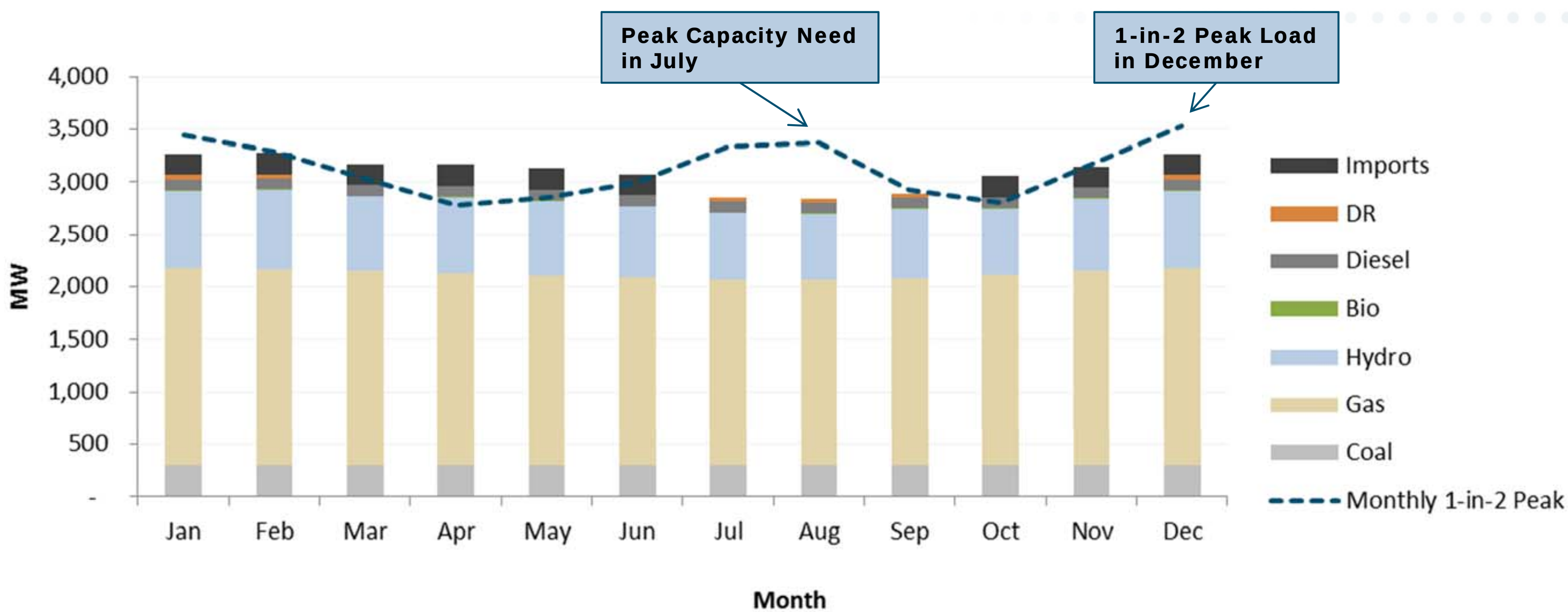
EXAMPLE RESULTS

Key inputs and assumptions for PGE system

- **Thermal resources**
  - Reliable capacities for each month, forced outage rates
- **Hydro resources**
  - Monthly dependable capacities for PGE units
  - Historical distribution of water availability for Mid-C contracts
- **Renewables**
  - 2004-2006 simulated production profiles for each wind site
  - 2006 simulated production profiles for distributed and utility clustered solar PV
- **Market purchases**
  - Up to 200 MW of imports are available to provide dependable capacity in non-summer months

PGE has higher capacity gap in summer than winter

- Load is higher in winter, with secondary peak in July / August
- Available resources lower in summer due to thermal de-rates, lower hydro output, and unavailability of imports



LOLP on PGE system is highest on summer afternoon, winter evening

- Chart shows hours of LOLP by month/hour time slice
- Sum of time slices is test year LOLE: 334 hours per year before adding resources

Hour of Day

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.006	0.004	0.000	0.000	0.000	0.000	0.001	0.018	0.000	0.000	0.006	0.016
2	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.002	0.000	0.000	0.001	0.003
3	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.001	0.002
4	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.002
5	0.003	0.003	0.003	0.001	0.000	0.000	0.000	0.001	0.001	0.000	0.004	0.007
6	0.076	0.075	0.044	0.014	0.000	0.000	0.001	0.006	0.009	0.011	0.111	0.119
7	0.410	0.304	0.170	0.008	0.001	0.001	0.005	0.022	0.038	0.026	0.297	0.719
8	1.083	0.687	0.404	0.041	0.004	0.005	0.033	0.115	0.142	0.112	0.546	2.088
9	2.949	1.780	0.822	0.035	0.009	0.028	0.138	0.524	0.190	0.100	1.233	4.238
10	2.665	1.420	0.673	0.035	0.019	0.078	0.572	1.435	0.291	0.076	1.335	3.930
11	2.447	1.138	0.485	0.029	0.039	0.220	1.726	3.085	0.517	0.066	1.174	3.722
12	1.956	0.887	0.351	0.022	0.070	0.457	3.052	4.768	0.780	0.065	1.069	3.317
13	1.805	0.696	0.188	0.024	0.112	0.725	4.610	6.326	1.325	0.065	0.986	2.872
14	1.690	0.475	0.137	0.019	0.168	1.127	6.348	8.401	1.869	0.074	0.848	2.271
15	1.333	0.323	0.081	0.013	0.241	1.468	7.661	9.801	2.454	0.067	0.720	1.760
16	1.128	0.283	0.061	0.012	0.302	1.850	8.454	10.537	3.148	0.069	0.775	1.927
17	1.418	0.447	0.091	0.011	0.343	2.099	8.708	10.611	3.333	0.129	1.219	3.194
18	2.554	0.833	0.181	0.013	0.374	1.812	7.832	9.690	3.081	0.196	2.250	5.259
19	4.958	1.404	0.271	0.008	0.237	1.210	6.038	8.302	2.385	0.323	3.829	7.906
20	5.198	1.837	0.532	0.014	0.130	0.588	4.319	6.678	1.697	0.298	3.333	7.091
21	3.921	1.248	0.497	0.025	0.067	0.277	2.817	4.833	1.223	0.166	2.357	4.945
22	2.487	0.696	0.161	0.008	0.028	0.131	1.388	2.613	0.373	0.030	1.294	2.812
23	0.852	0.212	0.016	0.001	0.001	0.014	0.181	0.584	0.047	0.003	0.485	0.921
24	0.120	0.032	0.001	0.000	0.000	0.000	0.011	0.069	0.001	0.000	0.089	0.130

Preliminary PRM is 15.1% for 2021 test year

- **A 1-annual-event-in-10-years standard (LOLE=2.4) implies an annual capacity shortage of 932 MW in 2021**
- **Equivalent to a 15.1% PRM**
  - PRM calculations use average of summer and winter reliable capacity for thermal and hydro resources
  - Annual ELCC used for wind and solar

Unit	MW
Natural Gas	1,821
Colstrip	296
Hydro Projects	575
Mid-C Hydro Agreements	123
Other Contracts	9
DSM	142
Renewables	98
Imports	61
Total Available Dependable Capacity	**3,125**
1-in-2 Peak Load	3,525
Planning Reserve Margin	533
Total Dependable Capacity Needed	**4,058**
Dependable Capacity Shortage	**932**
PRM (%)	**15.1%**

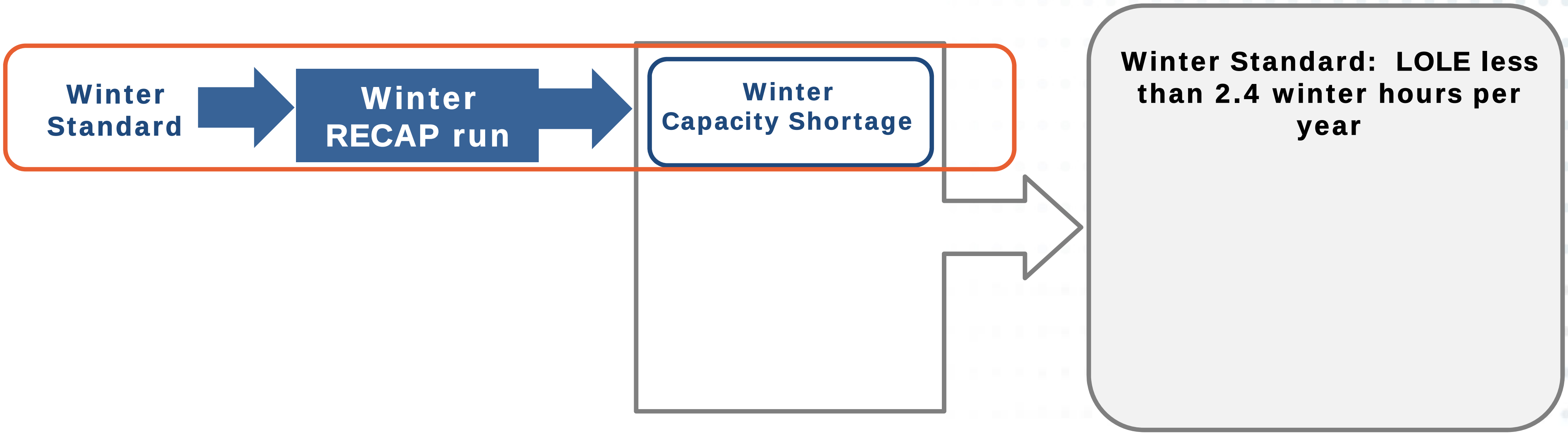
Preliminary results – do not cite

Seasonal LOLE

- PGE system is dual peaking, with non-zero LOLP in both summer and winter seasons
- E3 and PGE have developed a three-part test that ensures PGE system is resource adequate in both seasons while meeting annual LOLE target of 2.4 hours per / yr.
- PGE's system is defined to be resource adequate if it meets the following three loss-of-load standards:
  1. No more than one winter event in 10 years (2.4 winter hours);
  2. No more than one summer event in 10 years (2.4 summer hours); AND
  3. No more than one event in 10 years (2.4 anytime hours)

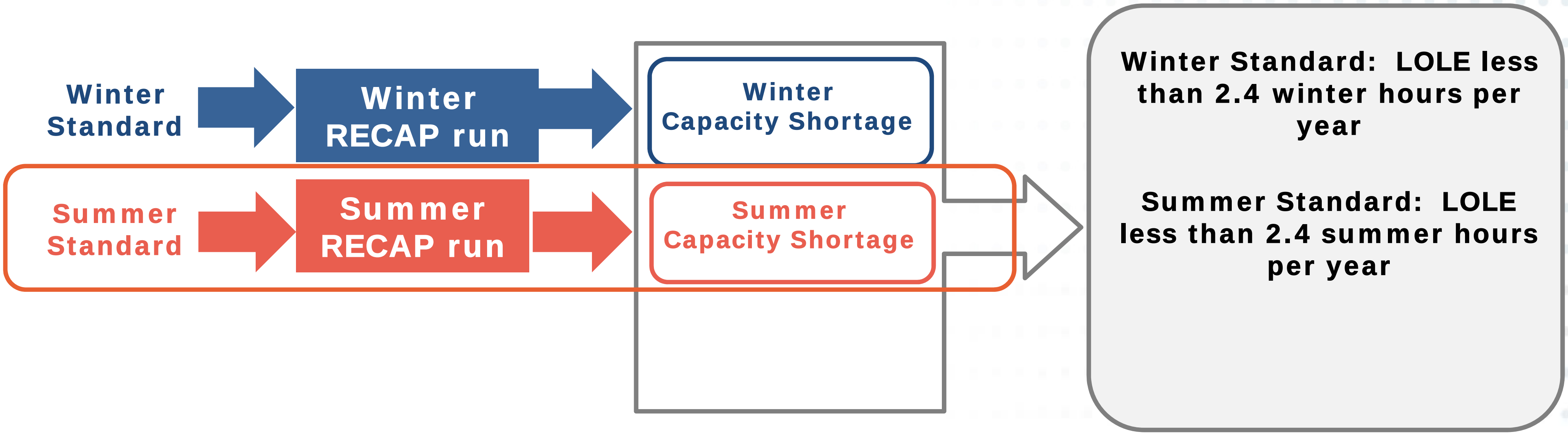
Independent seasonal and annual resource adequacy tests

- Winter need calculated using winter-only RECAP run
- Winter test intended to ensure no more than one winter loss-of-load event in 10 years



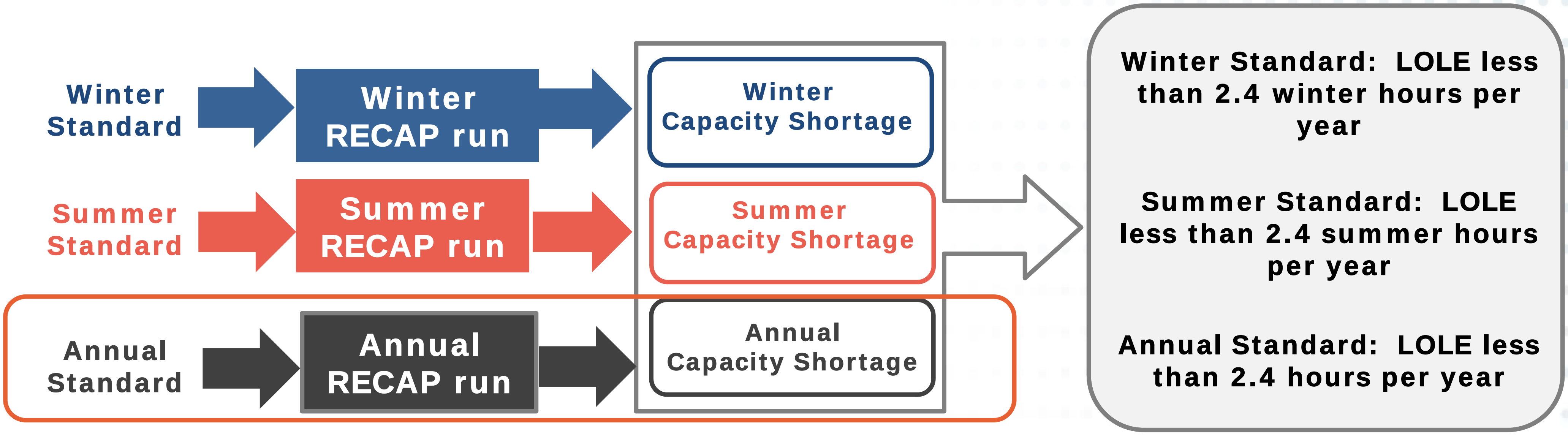
Independent seasonal and annual resource adequacy tests

- Summer need calculated independently using summer-only RECAP run
- Summer test intended to ensure no more than one summer loss-of-load event in 10 years



Independent seasonal and annual resource adequacy tests

- Annual need calculated independently using year-round RECAP run
- Annual test intended to ensure no more than one loss-of-load event in 10 years (any time of year)



Calculating Annual and Seasonal Planning Reserve Margins

- **Annual, winter and summer capacity requirements can be translated into annual, winter and summer PRMs**
- **Definitions:**
  - **Winter PRM:** Winter reliable MW divided by 1-in-2 winter peak load
  - **Summer PRM:** Summer reliable MW divided by 1-in-2 summer peak load
  - **Annual PRM:** Average of winter and summer reliable MW divided by 1-in-2 annual peak load

Preliminary Target PRM is 14.3% for Winter Test

- A 1-winter-event-in-10-years standard implies a winter capacity shortage of 630 MW in 2021
- Equivalent to a 14.3% PRM
- Winter standard is less conservative than annual standard

Unit	MW
Natural Gas	1,870
Colstrip	296
Hydro Projects	624
Mid-C Hydro Agreements	127
Other Contracts	9
DSM	142
Renewables	130
Imports	200
Total Available Dependable Capacity	**3,399**
1-in-2 Peak Load	3,525
Planning Reserve Margin	504
Total Dependable Capacity Needed	**4,029**
Dependable Capacity Shortage	**630**
PRM (%)	**14.3%**

Preliminary results – do not cite

Preliminary Target PRM is 14.6% for Summer Test

- A 1-summer-event-in-10-years standard implies a summer capacity shortage of 915 MW in 2021
- Equivalent to a 14.6% PRM
- Summer standard is less conservative than annual standard
- Thermal reliable capacity lower in summer

Unit	MW
Natural Gas	1,772
Colstrip	296
Hydro Projects	525
Mid-C Hydro Agreements	119
Other Contracts	9
DSM	142
Renewables	92
Imports	0
Total Available Dependable Capacity	**2,955**
1-in-2 Peak Load	3,376
Planning Reserve Margin	493
Total Dependable Capacity Needed	**3,869**
Dependable Capacity Shortage	**915**
PRM (%)	**14.6%**

Preliminary results – do not cite

Preliminary Target PRM is 15.1% for Annual Test

- A 1-annual-event-in-10-years standard (LOLE=2.4) implies an annual capacity shortage of 932 MW in 2021
- Equivalent to a 15.1% PRM
- More conservative than winter + summer
  - Winter + summer could result in 2 events in 10 yrs.

Unit	MW
Natural Gas	1,821
Colstrip	296
Hydro Projects	575
Mid-C Hydro Agreements	123
Other Contracts	9
DSM	142
Renewables	98
Imports	61
Total Available Dependable Capacity	**3,125**
1-in-2 Peak Load	3,525
Planning Reserve Margin	533
Total Dependable Capacity Needed	**4,058**
Dependable Capacity Shortage	**932**
PRM (%)	**15.1%**

Preliminary results – do not cite

Summary

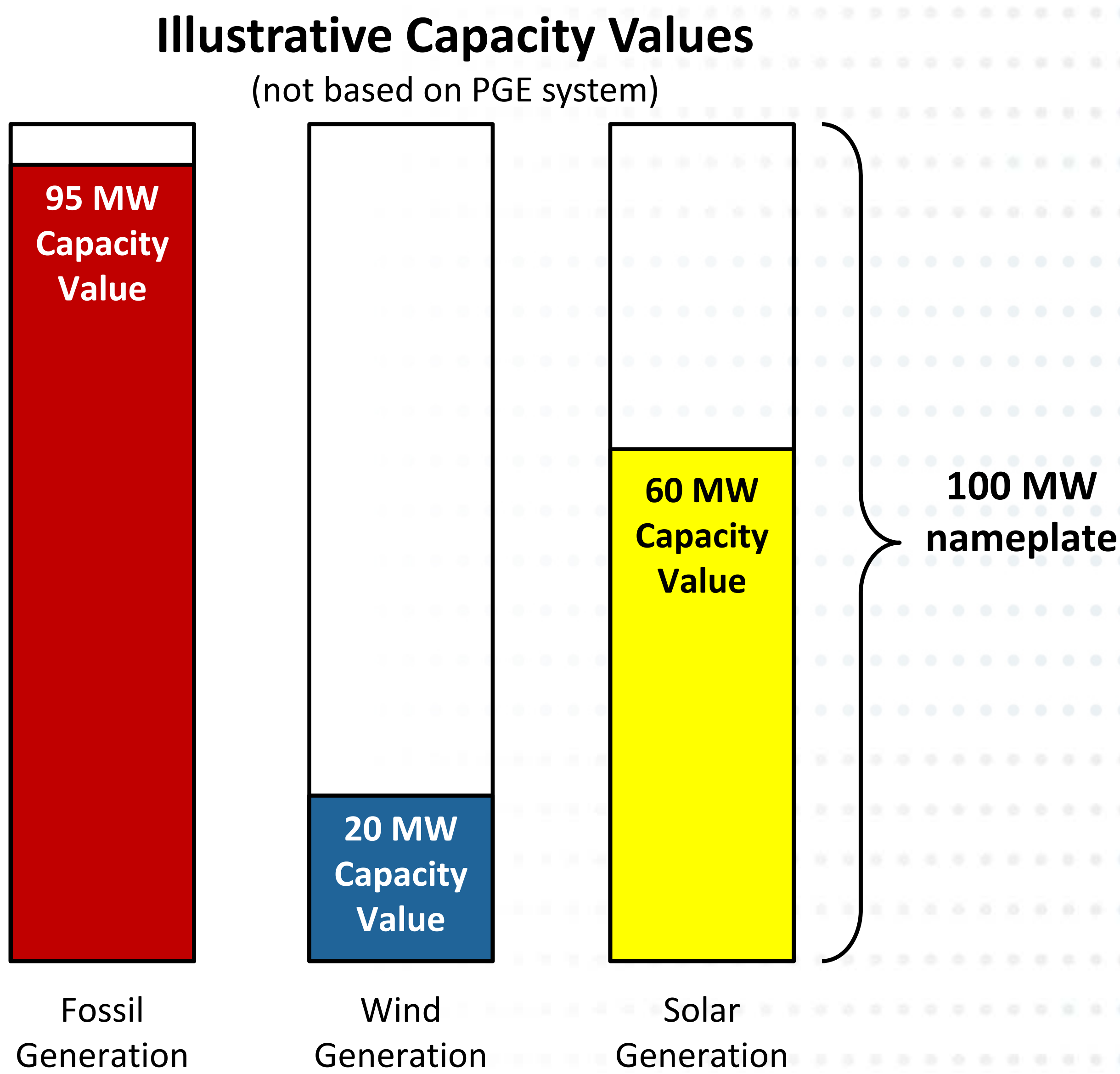
- **PGE has selected a resource adequacy standard of 1-day-in-10 years**
  - This is interpreted as 2.4 hours/year within the context of E3's RECAP model
- **E3 and PGE have developed independent winter, summer, and annual capacity requirements based on 1-day-in-10 years**
  1. No more than 2.4 winter hours of LOLE per year;
  2. No more than 2.4 summer hours of LOLE per year; AND
  3. No more than 2.4 hours of LOLE per year.
- **These requirements are translated into annual, summer and winter PRMs**

Energy+Environmental Economics

CAPACITY CONTRIBUTION OF DISPATCH-LIMITED RESOURCES

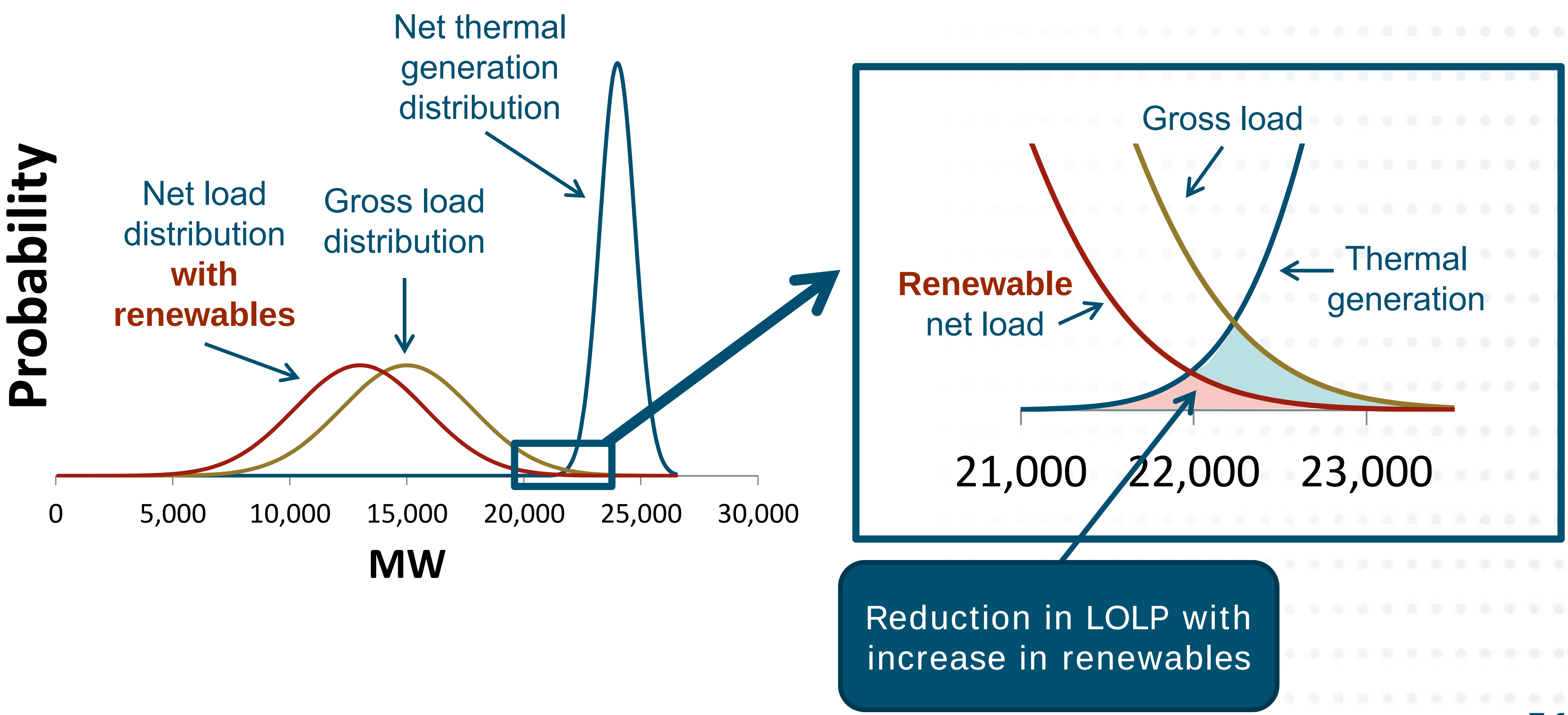
Renewable resources can contribute to system reliability

- No resource is perfectly available to help reduce LOLP
- By convention, dispatchable resources rated at nameplate and forced outages factored into PRM
- Non-dispatchable resources assigned "effective capacity" rating



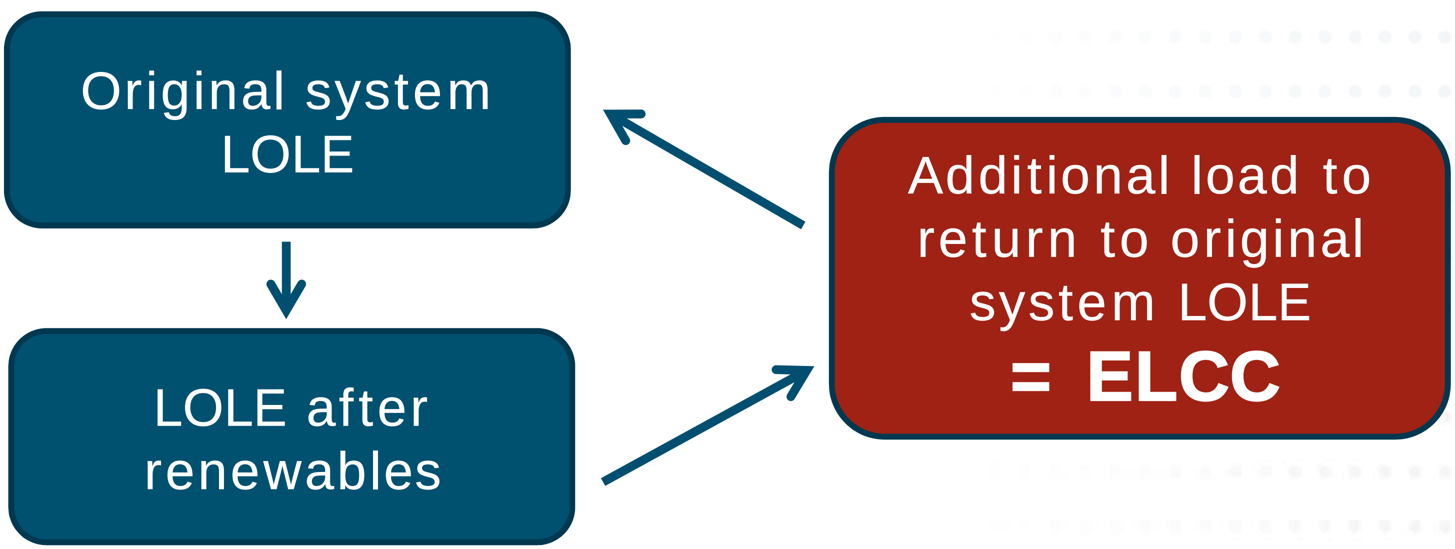
Renewables subtracted from load in LOLP calculations

- Renewable production is subtracted from gross load to yield “net load”, which is always lower
- LOLP decreases in every hour



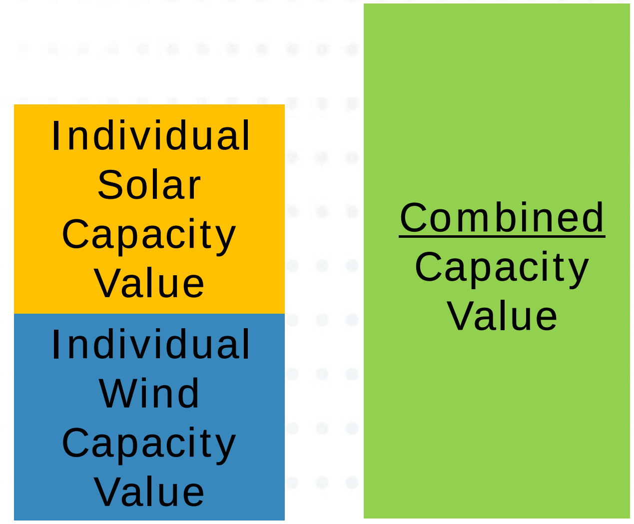
Calculating ELCC

- **Since LOLE has decreased with the addition of renewables, adding pure load will return the system to the original LOLE**
- **The amount of load that can be added to the system is the Effective Load-Carrying Capability (ELCC)**



Capacity value in applications

+ **The <u>portfolio capacity value</u> is the most relevant calculation to consider in resource planning**
  - Due to the complementarity of different resources the portfolio value will be higher than the sum of each individual resource measured alone
  - It is sometimes necessary to <u>attribute</u> the capacity value of the portfolio to individual resources
    - There are many options, but no standard or rigorous way to do this



+ **The <u>marginal capacity value</u>, given the existing portfolio, is more appropriate for use in procurement**
  - This value will <u>change over time</u> as the portfolio changes

Factors that affect the capacity value of variable generation

+ Coincidence with load

- Locations with better resources and better correlation with high load periods will have higher ELCC values

+ Coincidence with existing variable generation

- Common resource types show diminishing marginal returns; each additional plant has less value than the previous one

+ Production variability

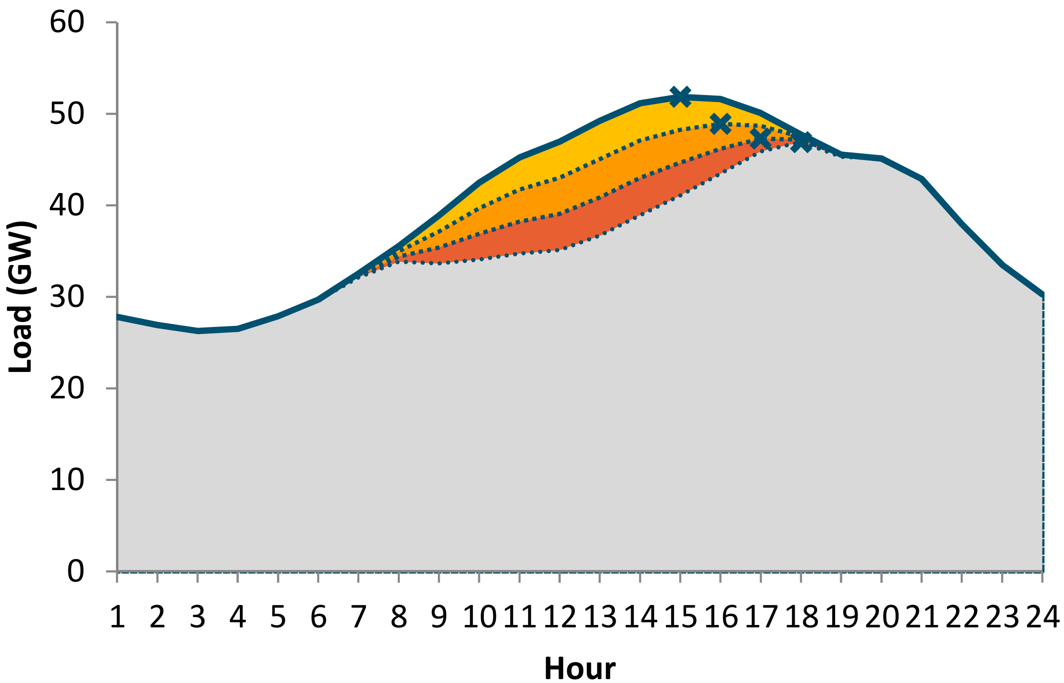
- Statistically, the possibility of low production during a peak load event reduces the value of a resource

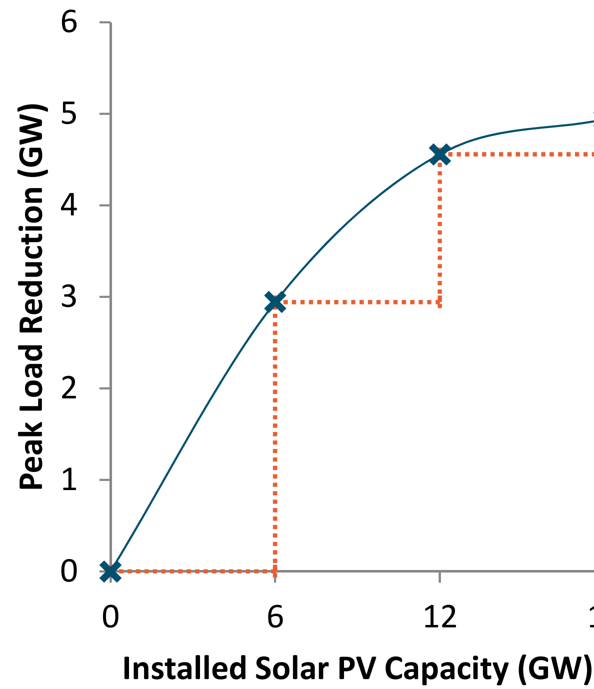
+ Location

- T&D losses are affected by resource size and location

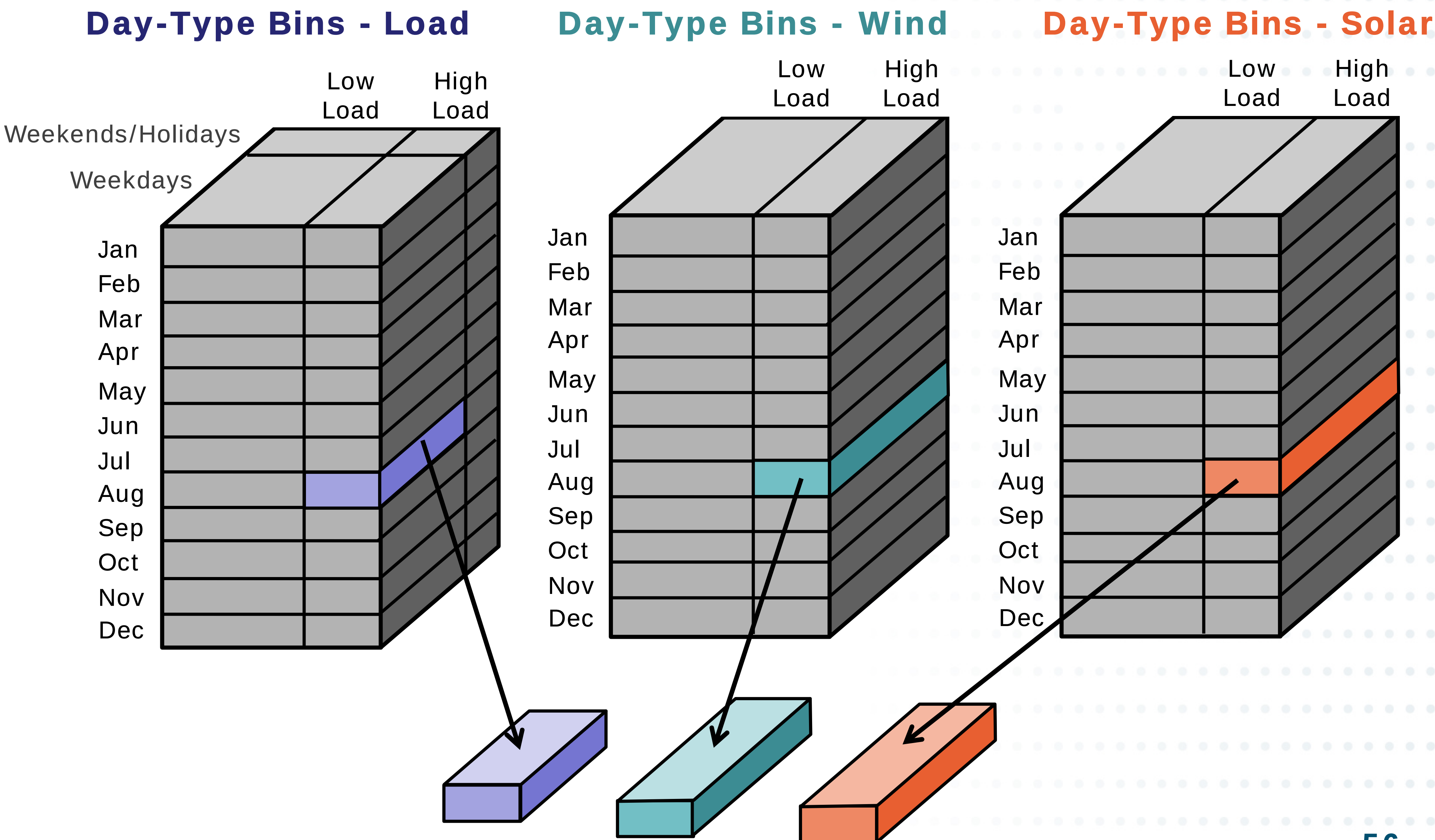
Marginal capacity value declines as penetration increases

- **A resource's contribution towards reliability depends on the other resources on the system**
- **The diminishing marginal peak load impact of solar PV is illustrative of this concept**
  - While the first increment of solar PV has a relatively large impact on peak, it also shifts the "net peak" to a later hour in the in day
  - This shift reduces the coincidence of the solar profile and the net peak such that additional solar resources have a smaller impact on the net peak



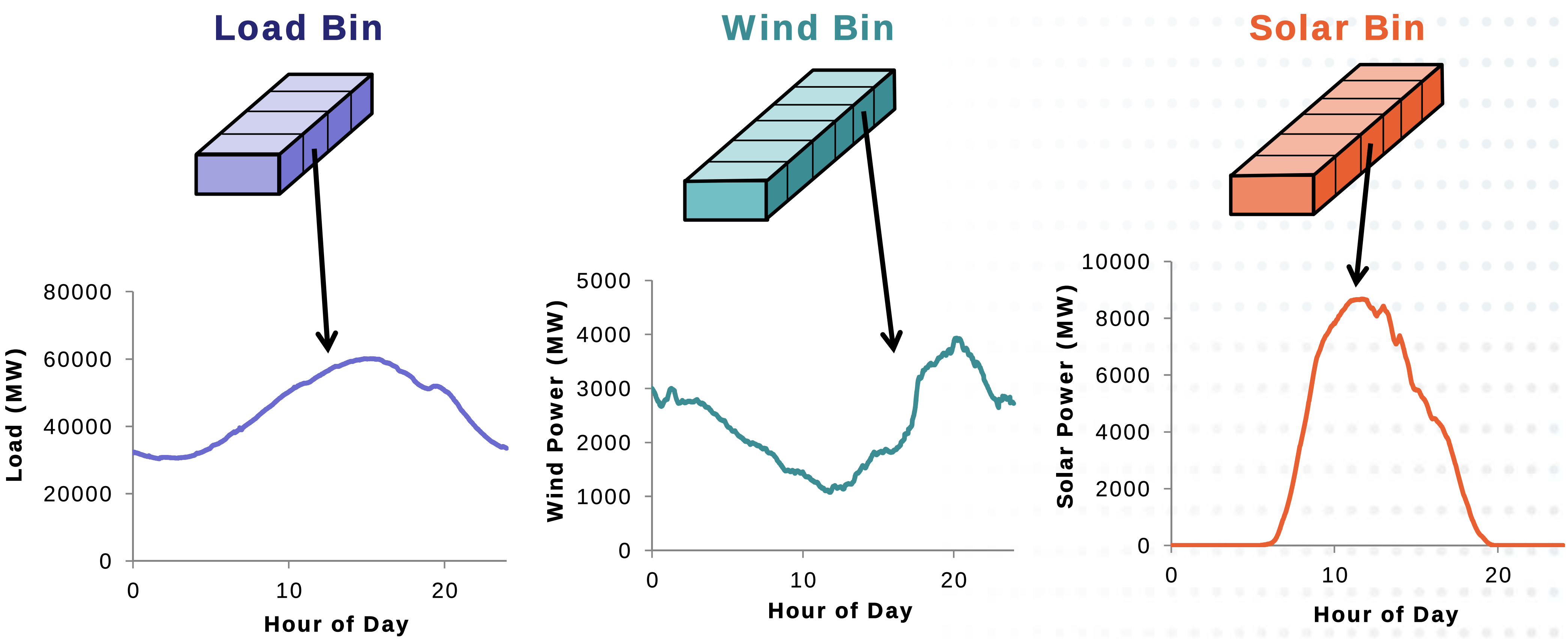


Example Draw: High Load Weekday in August



Example Draw: High Load Weekday in August

- Within each bin, choose each (load, wind, and solar) daily profile randomly, and independent of other daily profiles



Gorge wind has low output during hours with high LOLP

+ Coincidence of high renewable output and high system LOLE results in a higher ELCC

- System LOLE is concentrated in summer afternoon hours
- Sample Gorge wind site has relative low output on summer afternoons, resulting in low ELCC

System LOLE

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.006	0.004	0.000	0.000	0.000	0.000	0.001	0.018	0.000	0.000	0.006	0.016
2	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.002	0.000	0.000	0.001	0.003
3	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.001	0.002
4	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.002
5	0.003	0.003	0.003	0.001	0.000	0.000	0.000	0.001	0.001	0.000	0.004	0.007
6	0.076	0.075	0.044	0.014	0.000	0.000	0.001	0.006	0.009	0.011	0.111	0.119
7	0.410	0.304	0.170	0.008	0.001	0.001	0.005	0.022	0.038	0.026	0.297	0.719
8	1.083	0.687	0.404	0.041	0.004	0.005	0.033	0.115	0.142	0.112	0.546	2.088
9	2.949	1.780	0.822	0.035	0.009	0.028	0.138	0.524	0.190	0.100	1.233	4.238
10	2.665	1.420	0.673	0.035	0.019	0.078	0.572	1.435	0.291	0.076	1.335	3.930
11	2.447	1.138	0.485	0.029	0.039	0.220	1.726	3.085	0.517	0.066	1.174	3.722
12	1.956	0.887	0.351	0.022	0.070	0.457	3.052	4.768	0.780	0.065	1.069	3.317
13	1.805	0.696	0.188	0.024	0.112	0.725	4.610	6.326	1.325	0.065	0.986	2.872
14	1.690	0.475	0.137	0.019	0.168	1.127	6.348	8.401	1.869	0.074	0.848	2.271
15	1.333	0.323	0.081	0.013	0.241	1.468	7.661	9.801	2.454	0.067	0.720	1.760
16	1.128	0.283	0.061	0.012	0.302	1.850	8.454	10.537	3.148	0.069	0.775	1.927
17	1.418	0.447	0.091	0.011	0.343	2.099	8.708	10.611	3.333	0.129	1.219	3.194
18	2.554	0.833	0.181	0.013	0.374	1.812	7.832	9.690	3.081	0.196	2.250	5.259
19	4.958	1.404	0.271	0.008	0.237	1.210	6.038	8.302	2.385	0.323	3.829	7.906
20	5.198	1.837	0.532	0.014	0.130	0.588	4.319	6.678	1.697	0.298	3.333	7.091
21	3.921	1.248	0.497	0.025	0.067	0.277	2.817	4.833	1.223	0.166	2.357	4.945
22	2.487	0.696	0.161	0.008	0.028	0.131	1.388	2.613	0.373	0.030	1.294	2.812
23	0.852	0.212	0.016	0.001	0.001	0.014	0.181	0.584	0.047	0.003	0.485	0.921
24	0.120	0.032	0.001	0.000	0.000	0.000	0.011	0.069	0.001	0.000	0.089	0.130

Average Normalized Wind Output Sample Wind Site 1

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.691	0.482	0.499	0.378	0.293	0.258	0.186	0.230	0.285	0.401	0.591	0.581
2	0.701	0.481	0.508	0.386	0.302	0.283	0.163	0.229	0.283	0.399	0.579	0.578
3	0.699	0.469	0.512	0.410	0.297	0.281	0.136	0.217	0.290	0.387	0.574	0.593
4	0.683	0.452	0.499	0.423	0.294	0.264	0.125	0.215	0.292	0.393	0.559	0.589
5	0.686	0.434	0.498	0.421	0.302	0.270	0.124	0.208	0.291	0.421	0.534	0.584
6	0.675	0.415	0.513	0.404	0.291	0.280	0.121	0.197	0.272	0.418	0.523	0.590
7	0.672	0.418	0.519	0.400	0.288	0.295	0.112	0.194	0.265	0.420	0.529	0.593
8	0.670	0.437	0.517	0.395	0.288	0.289	0.093	0.189	0.263	0.402	0.540	0.595
9	0.667	0.459	0.529	0.390	0.270	0.254	0.083	0.171	0.256	0.398	0.544	0.586
10	0.657	0.460	0.532	0.354	0.247	0.225	0.075	0.151	0.230	0.403	0.556	0.563
11	0.643	0.435	0.510	0.324	0.227	0.211	0.063	0.121	0.212	0.374	0.553	0.551
12	0.636	0.403	0.460	0.310	0.209	0.194	0.065	0.119	0.203	0.336	0.536	0.541
13	0.628	0.372	0.437	0.296	0.219	0.190	0.074	0.119	0.197	0.294	0.509	0.516
14	0.610	0.356	0.428	0.293	0.224	0.203	0.089	0.127	0.192	0.287	0.489	0.488
15	0.601	0.346	0.428	0.291	0.219	0.215	0.108	0.136	0.189	0.286	0.471	0.482
16	0.598	0.335	0.420	0.281	0.225	0.226	0.124	0.150	0.194	0.287	0.464	0.471
17	0.613	0.339	0.414	0.283	0.231	0.240	0.148	0.172	0.199	0.289	0.474	0.471
18	0.631	0.350	0.423	0.298	0.262	0.259	0.171	0.180	0.221	0.285	0.503	0.500
19	0.646	0.358	0.405	0.296	0.280	0.252	0.170	0.197	0.236	0.297	0.533	0.538
20	0.650	0.393	0.398	0.279	0.277	0.249	0.177	0.222	0.232	0.324	0.545	0.566
21	0.661	0.426	0.426	0.287	0.264	0.236	0.183	0.208	0.246	0.353	0.575	0.577
22	0.660	0.443	0.451	0.284	0.243	0.217	0.192	0.211	0.269	0.371	0.592	0.583
23	0.670	0.447	0.491	0.296	0.249	0.226	0.197	0.217	0.283	0.378	0.586	0.588
24	0.674	0.464	0.509	0.341	0.271	0.236	0.186	0.225	0.281	0.388	0.598	0.596

Montana wind output is higher during hours with high LOLP

+ Coincidence of high renewable output and high system LOLE results in a higher ELCC

- System LOLE is concentrated in summer afternoon hours
- Sample Montana wind site has higher relative output on summer afternoons, resulting in higher ELCC

System LOLE

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.006	0.004	0.000	0.000	0.000	0.000	0.001	0.018	0.000	0.000	0.006	0.016
2	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.002	0.000	0.000	0.001	0.003
3	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.001	0.002
4	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.002
5	0.003	0.003	0.003	0.001	0.000	0.000	0.000	0.001	0.001	0.000	0.004	0.007
6	0.076	0.075	0.044	0.014	0.000	0.000	0.001	0.006	0.009	0.011	0.111	0.119
7	0.410	0.304	0.170	0.008	0.001	0.001	0.005	0.022	0.038	0.026	0.297	0.719
8	1.083	0.687	0.404	0.041	0.004	0.005	0.033	0.115	0.142	0.112	0.546	2.088
9	2.949	1.780	0.822	0.035	0.009	0.028	0.138	0.524	0.190	0.100	1.233	4.238
10	2.665	1.420	0.673	0.035	0.019	0.078	0.572	1.435	0.291	0.076	1.335	3.930
11	2.447	1.138	0.485	0.029	0.039	0.220	1.726	3.085	0.517	0.066	1.174	3.722
12	1.956	0.887	0.351	0.022	0.070	0.457	3.052	4.768	0.780	0.065	1.069	3.317
13	1.805	0.696	0.188	0.024	0.112	0.725	4.610	6.326	1.325	0.065	0.986	2.872
14	1.690	0.475	0.137	0.019	0.168	1.127	6.348	8.401	1.869	0.074	0.848	2.271
15	1.333	0.323	0.081	0.013	0.241	1.468	7.661	9.801	2.454	0.067	0.720	1.760
16	1.128	0.283	0.061	0.012	0.302	1.850	8.454	10.537	3.148	0.069	0.775	1.927
17	1.418	0.447	0.091	0.011	0.343	2.099	8.708	10.611	3.333	0.129	1.219	3.194
18	2.554	0.833	0.181	0.013	0.374	1.812	7.832	9.690	3.081	0.196	2.250	5.259
19	4.958	1.404	0.271	0.008	0.237	1.210	6.038	8.302	2.385	0.323	3.829	7.906
20	5.198	1.837	0.532	0.014	0.130	0.588	4.319	6.678	1.697	0.298	3.333	7.091
21	3.921	1.248	0.497	0.025	0.067	0.277	2.817	4.833	1.223	0.166	2.357	4.945
22	2.487	0.696	0.161	0.008	0.028	0.131	1.388	2.613	0.373	0.030	1.294	2.812
23	0.852	0.212	0.016	0.001	0.001	0.014	0.181	0.584	0.047	0.003	0.485	0.921
24	0.120	0.032	0.001	0.000	0.000	0.000	0.011	0.069	0.001	0.000	0.089	0.130

Average Normalized Wind Output Sample Wind Site 2

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.755	0.563	0.577	0.454	0.406	0.444	0.313	0.300	0.429	0.456	0.657	0.760
2	0.769	0.573	0.586	0.421	0.390	0.446	0.315	0.296	0.415	0.482	0.657	0.770
3	0.761	0.589	0.580	0.408	0.360	0.413	0.301	0.282	0.420	0.490	0.661	0.774
4	0.755	0.597	0.570	0.423	0.342	0.390	0.277	0.258	0.421	0.487	0.664	0.768
5	0.767	0.598	0.563	0.426	0.348	0.359	0.269	0.255	0.412	0.501	0.660	0.756
6	0.769	0.595	0.534	0.434	0.363	0.333	0.243	0.289	0.436	0.493	0.649	0.752
7	0.771	0.595	0.527	0.430	0.368	0.310	0.248	0.291	0.438	0.482	0.646	0.773
8	0.774	0.593	0.524	0.420	0.369	0.286	0.235	0.263	0.434	0.496	0.647	0.789
9	0.773	0.603	0.524	0.371	0.364	0.297	0.203	0.243	0.407	0.505	0.656	0.800
10	0.787	0.612	0.515	0.355	0.372	0.308	0.213	0.247	0.362	0.500	0.669	0.810
11	0.785	0.609	0.510	0.373	0.390	0.345	0.260	0.281	0.382	0.480	0.664	0.804
12	0.762	0.617	0.559	0.405	0.414	0.382	0.309	0.325	0.427	0.498	0.666	0.787
13	0.748	0.633	0.585	0.450	0.439	0.415	0.340	0.346	0.461	0.531	0.668	0.767
14	0.755	0.639	0.598	0.476	0.468	0.456	0.381	0.362	0.485	0.552	0.661	0.768
15	0.753	0.640	0.600	0.474	0.465	0.487	0.392	0.369	0.504	0.559	0.671	0.759
16	0.729	0.642	0.599	0.474	0.482	0.506	0.419	0.385	0.506	0.550	0.683	0.748
17	0.719	0.648	0.585	0.457	0.492	0.506	0.403	0.376	0.483	0.531	0.683	0.735
18	0.715	0.652	0.588	0.456	0.498	0.502	0.363	0.356	0.445	0.523	0.677	0.745
19	0.730	0.640	0.583	0.430	0.493	0.482	0.342	0.313	0.437	0.508	0.677	0.745
20	0.733	0.653	0.582	0.424	0.443	0.486	0.304	0.345	0.430	0.504	0.676	0.733
21	0.750	0.633	0.595	0.448	0.422	0.457	0.285	0.354	0.439	0.510	0.673	0.732
22	0.748	0.613	0.587	0.461	0.409	0.426	0.296	0.304	0.456	0.494	0.666	0.740
23	0.745	0.594	0.560	0.445	0.407	0.419	0.316	0.312	0.467	0.464	0.661	0.729
24	0.760	0.567	0.555	0.427	0.408	0.426	0.305	0.318	0.447	0.445	0.665	0.733

Solar output is high during summer peak hours

+ Coincidence of high renewable output and high system LOLE results in a higher ELCC

- System LOLE is concentrated in summer afternoon hours
- Solar PV has high output on summer afternoons, resulting in high ELCC

System LOLE

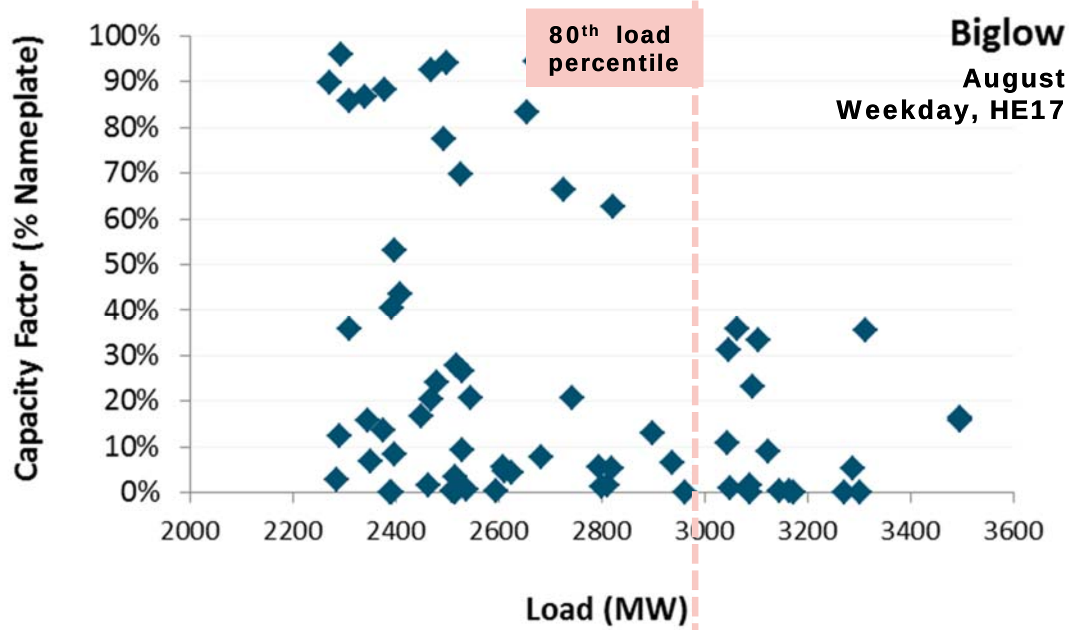
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.006	0.004	0.000	0.000	0.000	0.000	0.001	0.018	0.000	0.000	0.006	0.016
2	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.002	0.000	0.000	0.001	0.003
3	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.001	0.002
4	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.002
5	0.003	0.003	0.003	0.001	0.000	0.000	0.000	0.001	0.001	0.000	0.004	0.007
6	0.076	0.075	0.044	0.014	0.000	0.000	0.001	0.006	0.009	0.011	0.111	0.119
7	0.410	0.304	0.170	0.008	0.001	0.001	0.005	0.022	0.038	0.026	0.297	0.719
8	1.083	0.687	0.404	0.041	0.004	0.005	0.033	0.115	0.142	0.112	0.546	2.088
9	2.949	1.780	0.822	0.035	0.009	0.028	0.138	0.524	0.190	0.100	1.233	4.238
10	2.665	1.420	0.673	0.035	0.019	0.078	0.572	1.435	0.291	0.076	1.335	3.930
11	2.447	1.138	0.485	0.029	0.039	0.220	1.726	3.085	0.517	0.066	1.174	3.722
12	1.956	0.887	0.351	0.022	0.070	0.457	3.052	4.768	0.780	0.065	1.069	3.317
13	1.805	0.696	0.188	0.024	0.112	0.725	4.610	6.326	1.325	0.065	0.986	2.872
14	1.690	0.475	0.137	0.019	0.168	1.127	6.348	8.401	1.869	0.074	0.848	2.271
15	1.333	0.323	0.081	0.013	0.241	1.468	7.661	9.801	2.454	0.067	0.720	1.760
16	1.128	0.283	0.061	0.012	0.302	1.850	8.454	10.537	3.148	0.069	0.775	1.927
17	1.418	0.447	0.091	0.011	0.343	2.099	8.708	10.611	3.333	0.129	1.219	3.194
18	2.554	0.833	0.181	0.013	0.374	1.812	7.832	9.690	3.081	0.196	2.250	5.259
19	4.958	1.404	0.271	0.008	0.237	1.210	6.038	8.302	2.385	0.323	3.829	7.906
20	5.198	1.837	0.532	0.014	0.130	0.588	4.319	6.678	1.697	0.298	3.333	7.091
21	3.921	1.248	0.497	0.025	0.067	0.277	2.817	4.833	1.223	0.166	2.357	4.945
22	2.487	0.696	0.161	0.008	0.028	0.131	1.388	2.613	0.373	0.030	1.294	2.812
23	0.852	0.212	0.016	0.001	0.001	0.014	0.181	0.584	0.047	0.003	0.485	0.921
24	0.120	0.032	0.001	0.000	0.000	0.000	0.011	0.069	0.001	0.000	0.089	0.130

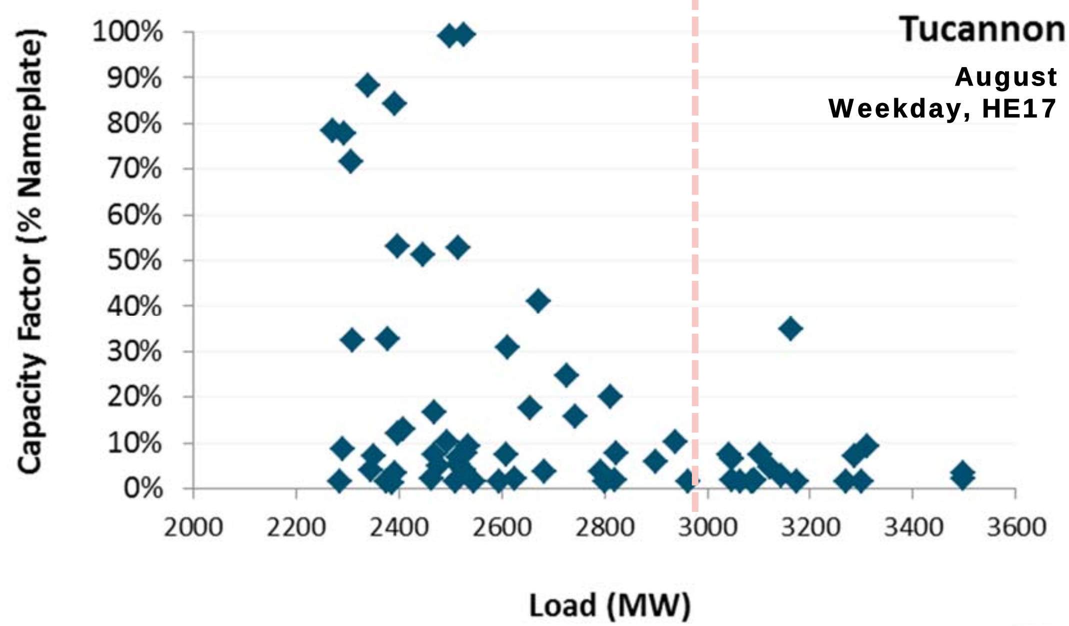
Average Normalized Solar Output Sample Site

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
3	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
4	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
5	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
6	0.000	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
7	0.000	0.000	0.000	0.009	0.087	0.118	0.091	0.016	0.000	0.000	0.000	0.000
8	0.000	0.000	0.018	0.170	0.261	0.257	0.272	0.203	0.141	0.013	0.000	0.000
9	0.003	0.077	0.211	0.344	0.438	0.423	0.467	0.432	0.415	0.271	0.076	0.003
10	0.280	0.416	0.401	0.478	0.578	0.568	0.629	0.608	0.584	0.509	0.349	0.280
11	0.425	0.551	0.487	0.602	0.664	0.644	0.723	0.707	0.685	0.617	0.430	0.441
12	0.383	0.593	0.557	0.660	0.701	0.707	0.773	0.766	0.756	0.669	0.426	0.443
13	0.385	0.586	0.568	0.678	0.722	0.735	0.791	0.809	0.768	0.678	0.423	0.472
14	0.382	0.571	0.539	0.699	0.708	0.734	0.788	0.807	0.772	0.669	0.367	0.467
15	0.358	0.541	0.526	0.658	0.660	0.686	0.753	0.770	0.739	0.615	0.306	0.449
16	0.331	0.475	0.487	0.587	0.587	0.628	0.696	0.710	0.672	0.571	0.247	0.393
17	0.238	0.387	0.402	0.493	0.526	0.546	0.604	0.636	0.561	0.415	0.124	0.218
18	0.059	0.208	0.257	0.358	0.404	0.440	0.464	0.479	0.374	0.154	0.006	0.001
19	0.000	0.005	0.074	0.180	0.232	0.271	0.297	0.269	0.120	0.001	0.000	0.000
20	0.000	0.000	0.000	0.021	0.072	0.113	0.113	0.056	0.001	0.000	0.000	0.000
21	0.000	0.000	0.000	0.000	0.001	0.004	0.003	0.000	0.000	0.000	0.000	0.000
22	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
24	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Gorge wind is negatively correlated with load during summer peak hours

+ **Correlation between load and renewable output may exist even within each month-hour-day type**
  - E.g. decrease in wind output in high load hours, as both are correlated to high temperatures
+ **To capture these correlations, fractions of gross load are binned separately**
  - 80th load percentile used
+ **Additional data on renewable output would improve accuracy of ELCC estimates**





Preliminary results – do not cite

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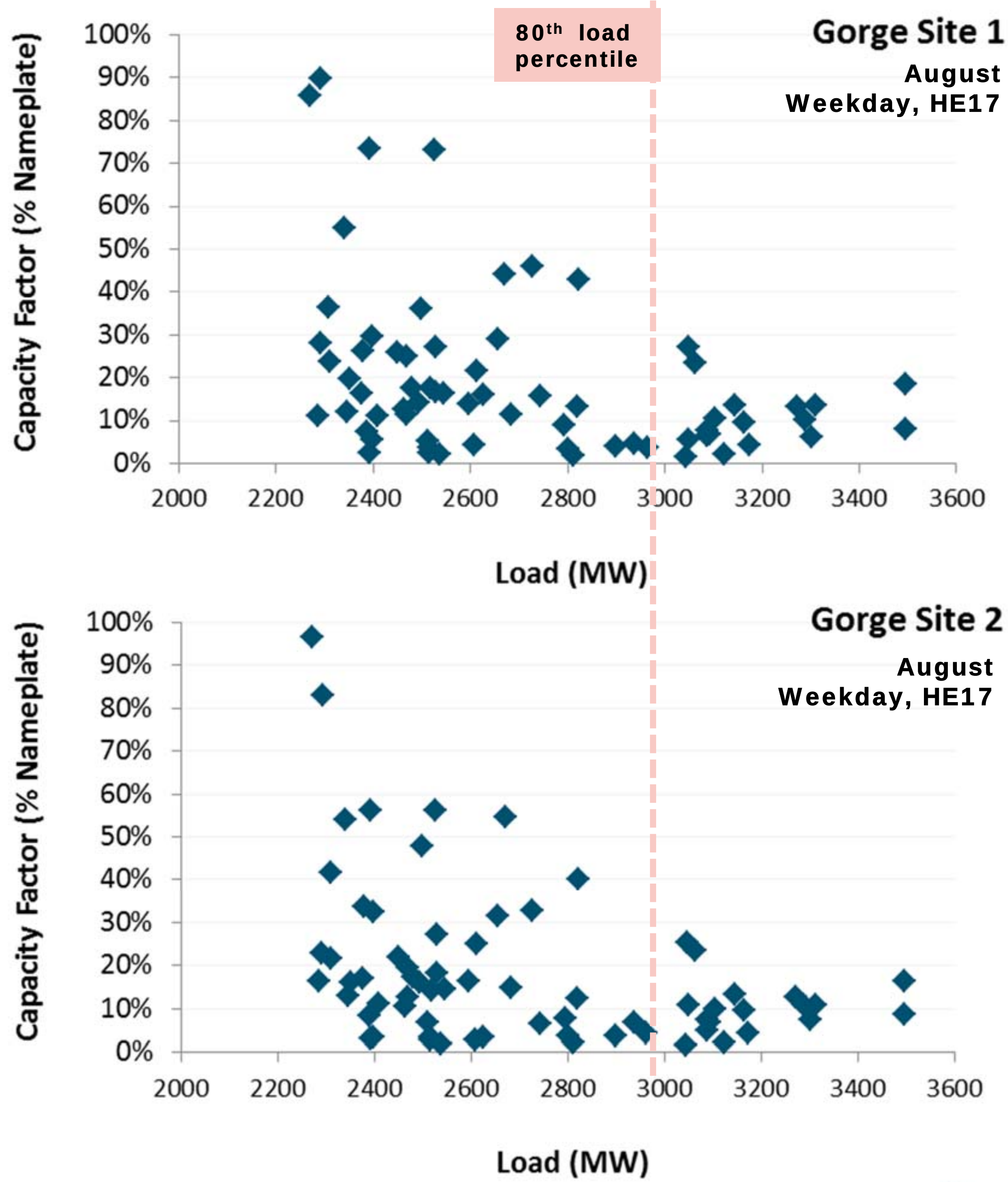


Preliminary results – do not cite

Preliminary ELCC for PGE's current renewable portfolio is 11.4%

	Winter	Summer	Annual
Nameplate rating MW	861	861	861
Portfolio ELCC (MW)	130	92	98
Portfolio ELCC (% of nameplate MW)	15.1%	10.7%	11.4%

Preliminary results – do not cite

+ **PGE portfolio currently has 861 MW of renewables**
  - Most is wind capacity
  - Total energy penetration equal to 12.6% of 2021 load
+ **ELCC value calculated for the entire existing portfolio**
  - Incorporates correlations and diversity among resources
  - No attribution of portfolio value to individual resources

Preliminary marginal ELCC of incremental resources

- **Marginal ELCC measures the additional ELCC provided by adding new resources to the portfolio**
- **Sample portfolio includes two Gorge sites and PV**
  - The Gorge sites add little diversity to the existing portfolio and have relatively low ELCCs
  - Incremental PV resource has higher ELCC due to its high summer capacity factors

Resource	Nameplate Rating (MW)	Annual ELCC
Incremental Wind Sites	665 MW	68 MW (10%)
Incremental Solar Sites	142 MW	66 MW (46%)
Total Incremental Portfolio	807 MW	138 MW (17%)

Preliminary results – do not cite

Preliminary marginal ELCC of incremental resources by season

- Gorge wind resources have higher ELCC in winter than in the summer
- Solar PV has high summer value due to coincidence of output with peak needs, but very low winter value due to nighttime peak loads
- Portfolio effects result in similar total incremental ELCC for all three tests

Resource	Nameplate Rating (MW)	Winter ELCC	Summer ELCC
Incremental Wind Sites	665 MW	129 MW (19%)	61 MW (9%)
Incremental Solar Sites	142 MW	14 MW (10%)	77 MW (55%)
Total Incremental Portfolio	807 MW	147 MW (18%)	140 MW (17%)

Preliminary results – do not cite

Energy+Environmental Economics

Flexibility Assessment Using E3's Renewable Energy Flexibility Model

Elaine Hart, Managing Consultant

Background

+ **Introduction of variable renewables has shifted the capacity planning paradigm**

+ **PGE has been directed by the Oregon PUC to provide an “Evaluation of new analytical tools for optimizing flexible resource mix to integrate load and variable resources”**

+ **The new planning problem consists of two related questions:**
    1. How many MW of <u>dispatchable</u> resources are needed to (a) meet load, and (b) meet flexibility requirements
    2. What is the optimal mix of new resources, given the characteristics of the existing fleet of conventional and renewable resources?

Flexibility Planning Challenges

1. Downward ramping capability

Thermal & hydro resources operating to serve loads at night must be ramped downward and potentially shut down to make room for an influx of solar energy after the sun rises.

2. Minimum generation flexibility

Overgeneration may occur during hours with high renewable production even if thermal resources and imports are reduced to their minimum levels. A system with more flexibility to reduce thermal generation will incur less overgeneration.

3. Upward ramping capability

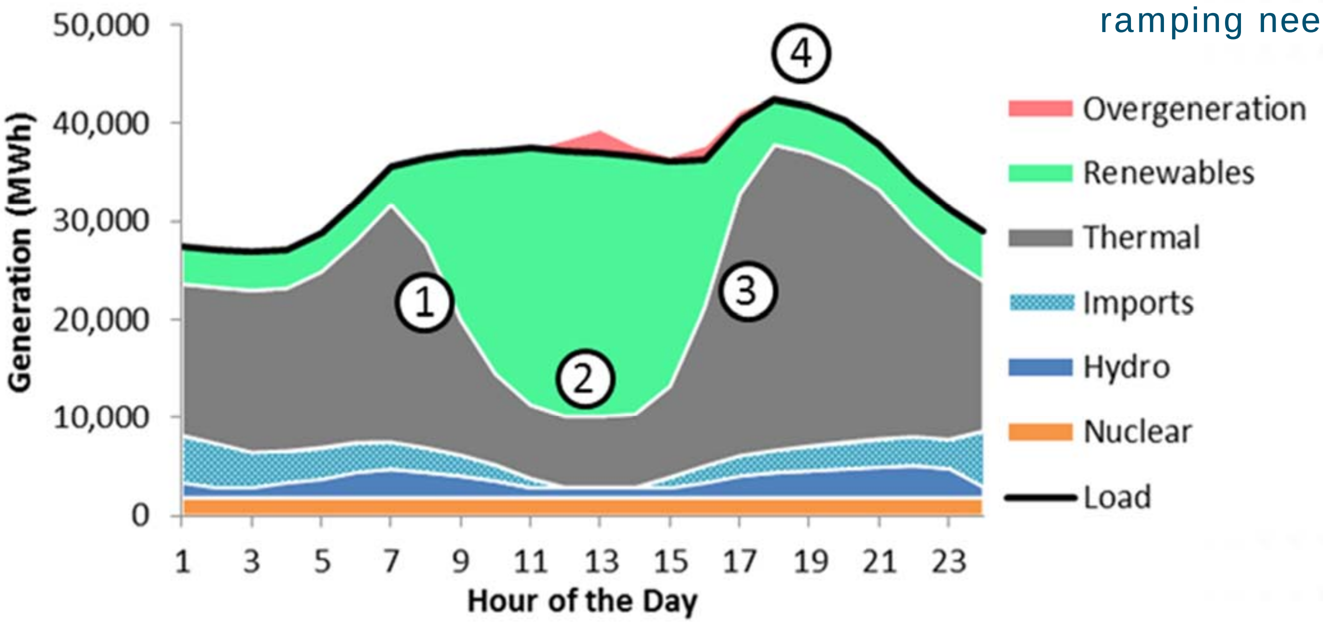
Thermal & hydro resources must ramp up quickly and new units may be required to start up to meet a high net peak demand that occurs shortly after sundown.

4. Peaking capability

The system will need enough resources to meet the highest peak loads with sufficient reliability.

5. Sub-hourly flexibility (not shown in chart)

Flexible capacity needed to meet sub-hourly ramping needs.



There are a number of potential flexibility constraints that can become binding at various times and on various systems.

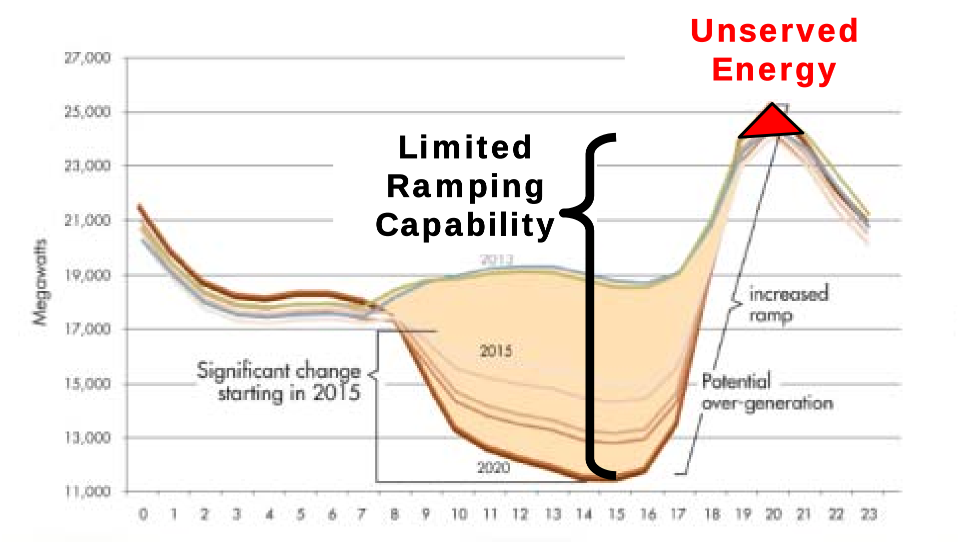
Many Resource Characteristics Can Be Important for Flexibility

Characteristic	How it helps with system flexibility
Upward ramping capability on multiple time scales: • 1 minute, 5 minutes, 20 minutes, 1 hour, 3 hours, 5 hours	Helps meet upward ramping demands
Downward ramping capability on multiple time scales: • 1 minute, 5 minutes, 20 minutes, 1 hour, 3 hours, 5 hours	Helps meet downward ramping demands
Minimum generation levels	Lower minimum generation levels can help meet upward ramping needs while avoiding overgeneration
Start time	Faster start times help meet upward ramping demands
Shut-down time	Faster shut-down times help avoid overgeneration
Minimum run times	Shorter minimum run times help avoid overgeneration
Minimum down times	Shorter minimum down times can help meet upward ramping needs
Number of starts	If starts are limited under air permits, units are less available to meet ramping needs

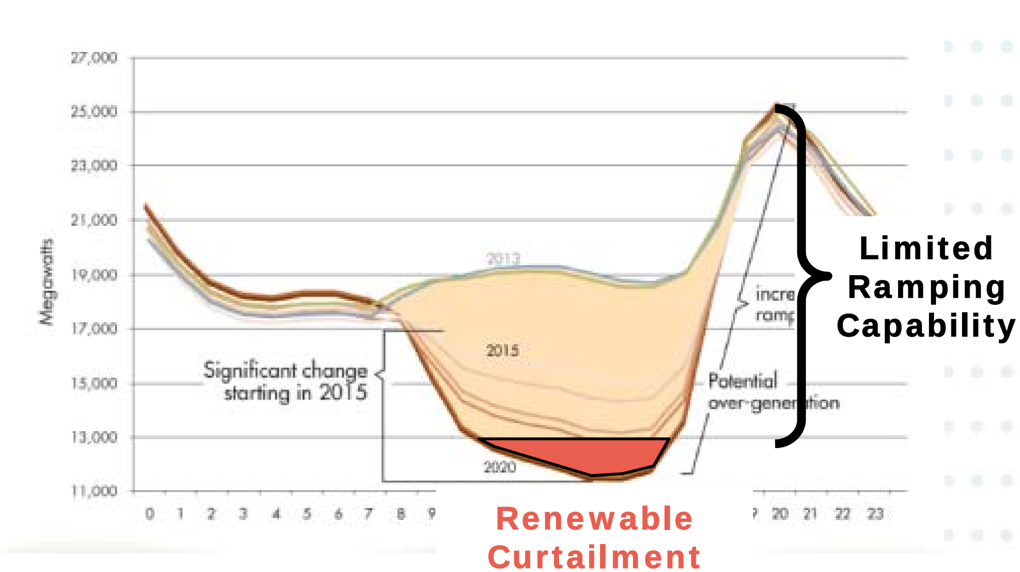
Flexibility and Economics

- **Renewable integration can be framed as an economic operating decision**
- **Flexibility violations in upward and downward directions are substitutes for one another**
  - Upward ramping shortages can be solved using renewable curtailment

Strategy to Minimize Downward Violations

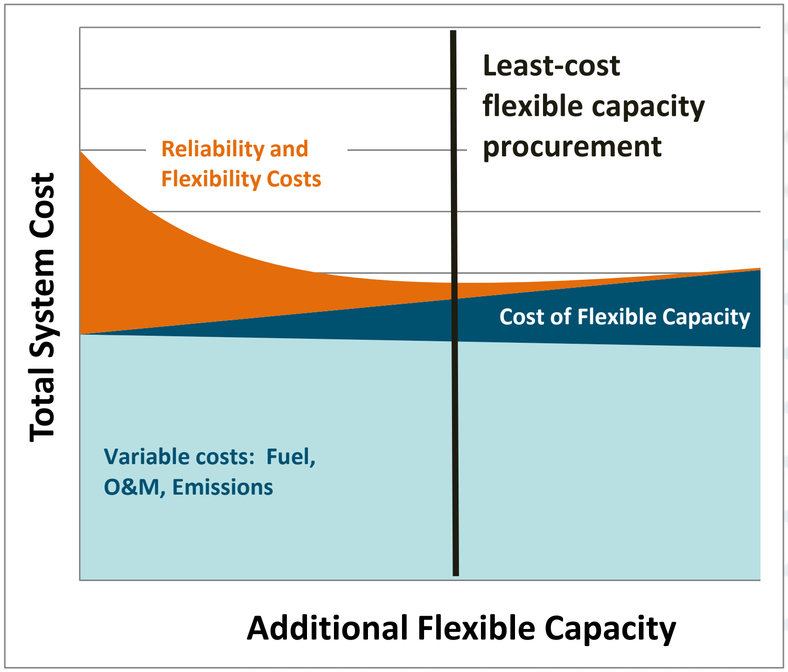


Strategy to Minimize Upward Violations



Cost-Effective Flexibility Investment

- **Curtailment can be difficult if relied on as a long-term grid flexibility solution**
  - Must compensate curtailed generator
    - Requires systems in place to calculate generator lost revenue
  - Must replace renewable energy
    - Replacement energy may itself be subject to curtailment
- **Investment in flexibility reduces frequency and duration of flexibility violation events**
  - Reduces dispatch cost
  - Improves compliance with NERC operating standards
  - Improves compliance with policy



Analysis question:
When does investment in grid flexibility become cost-effective relative to default solution of renewable curtailment?

Scope of this project

+ **Estimate expected flexibility violations**
  - REFLEX: Adapted production simulation methodology designed to assess system flexibility
+ **Identify and assess candidate portfolios of flexibility solutions**
  - Renewable portfolio diversity
  - Energy storage
  - Peaking thermal resources

Energy+Environmental Economics

REFLEX METHODOLOGY

Renewable Energy Flexibility (REFLEX) Model

+ **REFLEX answers critical questions about flexibility need through adapted production simulation**
  - **Captures wide distribution of operating conditions** through Monte Carlo draws of operating days
  - **Illuminates the significance of the operational challenges** by calculating the likelihood, magnitude, duration & cost of flexibility violations
  - **Assesses the benefits and costs** of investment to avoid flexibility violations

Available as standalone model or add-on to Plexos for Power Systems

REFLEX Has Features of Reliability and Production Simulation Models

LOLP Model

- Reliability/Resource Adequacy
- E.g., RECAP, GE-MARS, SERVM
- Determines quantity of resources needed to meet load reliably by calculating metrics such as loss-of-load probability (LOLP)
- Must consider a broad range of ***stochastic*** variables such as load, wind, solar, hydro and generator outages in order to get robust probabilities

Production Simulation

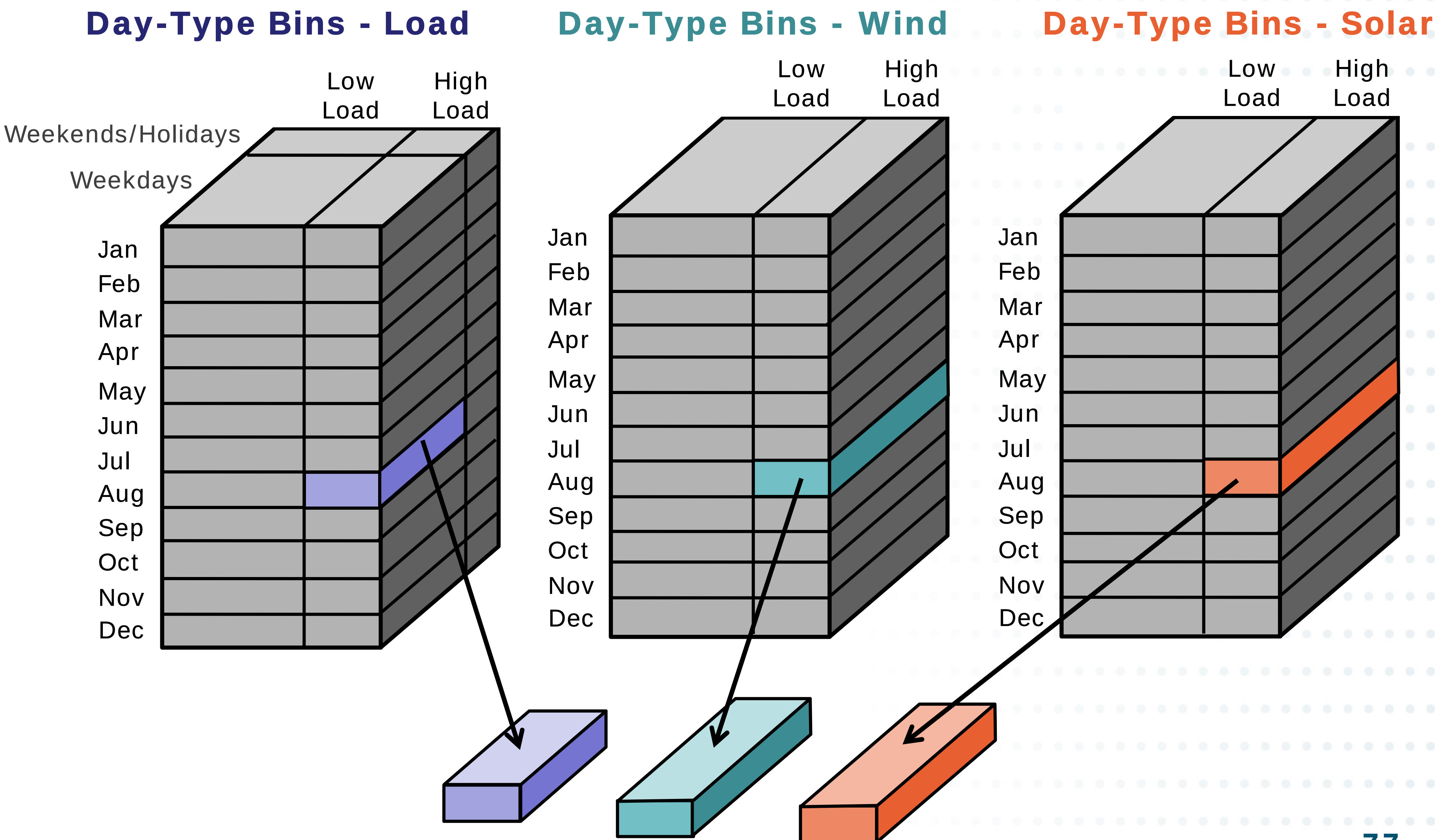
- Production simulation
- E.g., GridView, PLEXOS
- Calculates least-cost dispatch subject to generation and transmission constraints
- Used to estimate operational requirements and transmission flows
- Computation time typically allows only a single, ***deterministic*** case

REFLEX addresses the long-term uncertainties of an LOLP model with the operational detail of production simulation

Flexibility Metrics

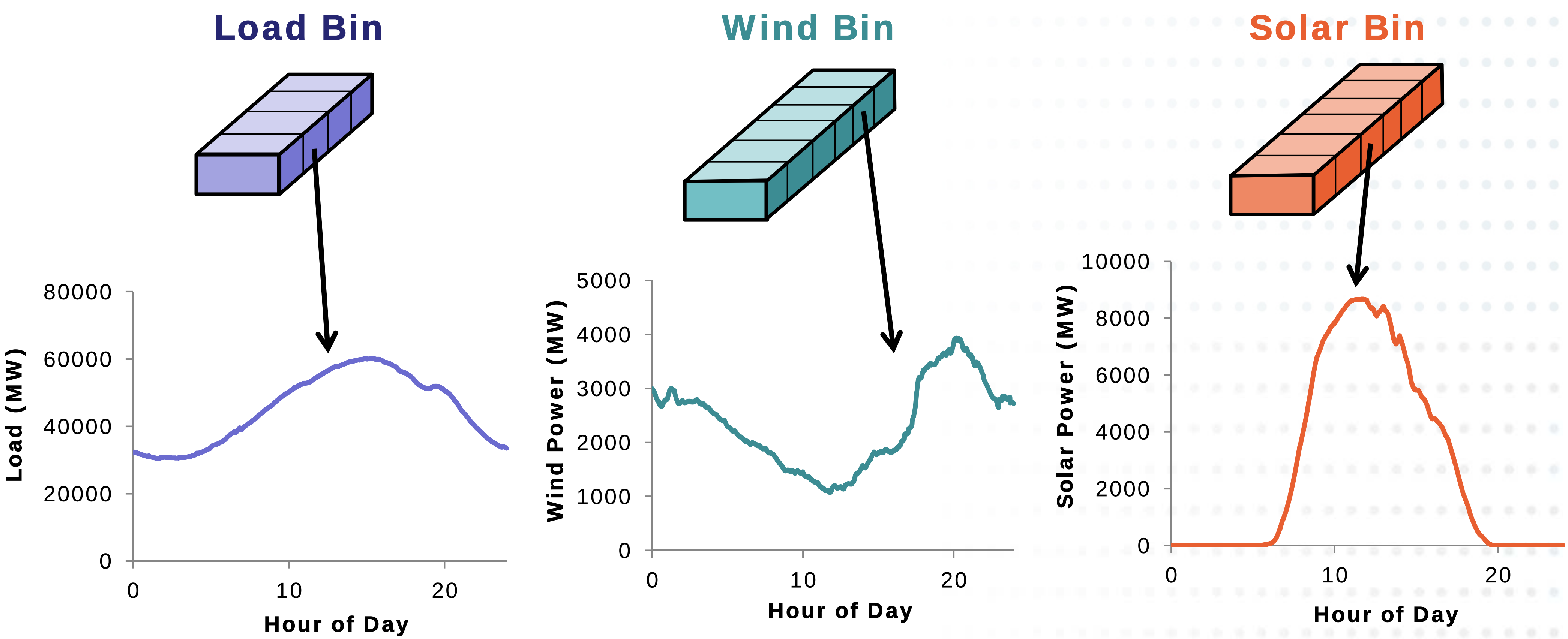
+ **Flexibility violations occur when the power system cannot meet all changes in net load over all time scales**
+ **REFLEX reports two categories of flexibility violations:**
  - EUE: Expected Unserved Energy
  - EOG: Expected Overgeneration, aka renewable curtailment
    - Hourly and within-hour timescales
+ **Economic parameters are also required:**
  - VUE: Value of Unserved Energy
    - **$2,000–50,000**/MWh based on value of lost load
  - VOG: Value of Overgeneration
    - **$30-150**/MWh based on replacement cost of renewable energy
+ **REFLEX also reports production costs & CO2 emissions**

Stochastic Sampling of Load, Wind, and Solar



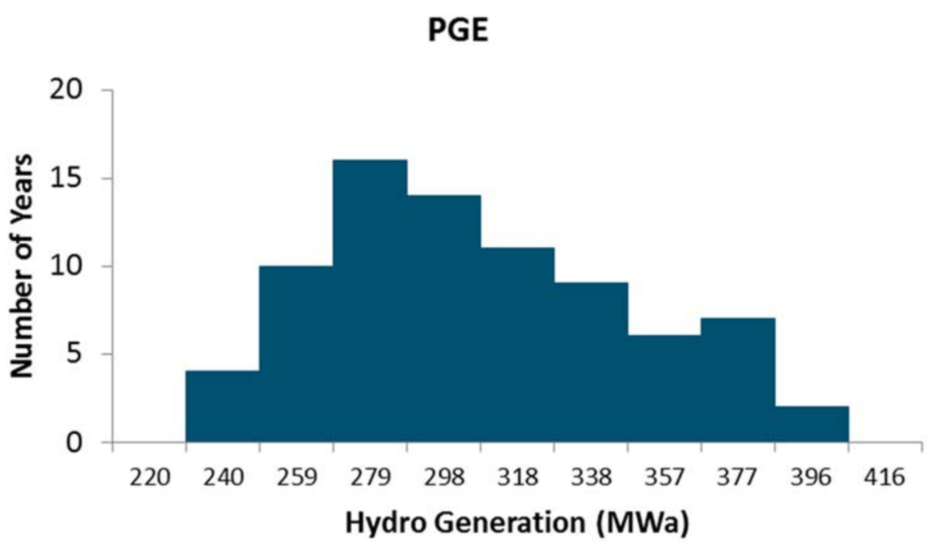
Example Draw: High Load Weekday in August

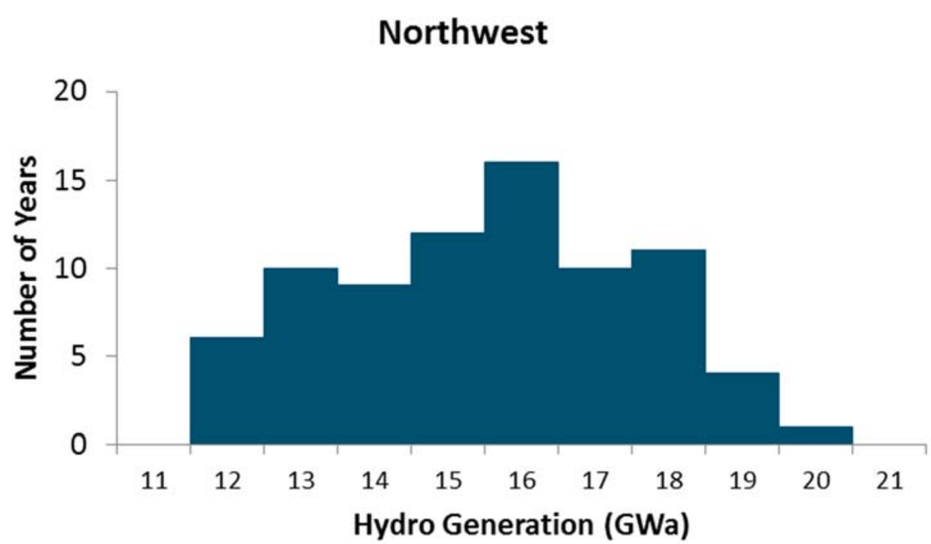
- **Within each bin, choose each (load, wind, and solar) daily profile randomly, and independent of other daily profiles**
  - 24 hour spin-up and spin-down periods included in the optimization



Stochastic Sampling of Hydro Conditions

- Traditional production simulation analysis typically relies on a single year of hydro conditions
- REFLEX samples energy budgets from a wide range of historical hydro conditions (1928-2008)
  - Northwest Power and Conservation Council (NWPCC) simulated monthly output data by plant for 1928-2008 hydro conditions
  - NWPCC data used to supplement PGE data to characterize full range of historical hydro conditions





Source: Northwest Power Council

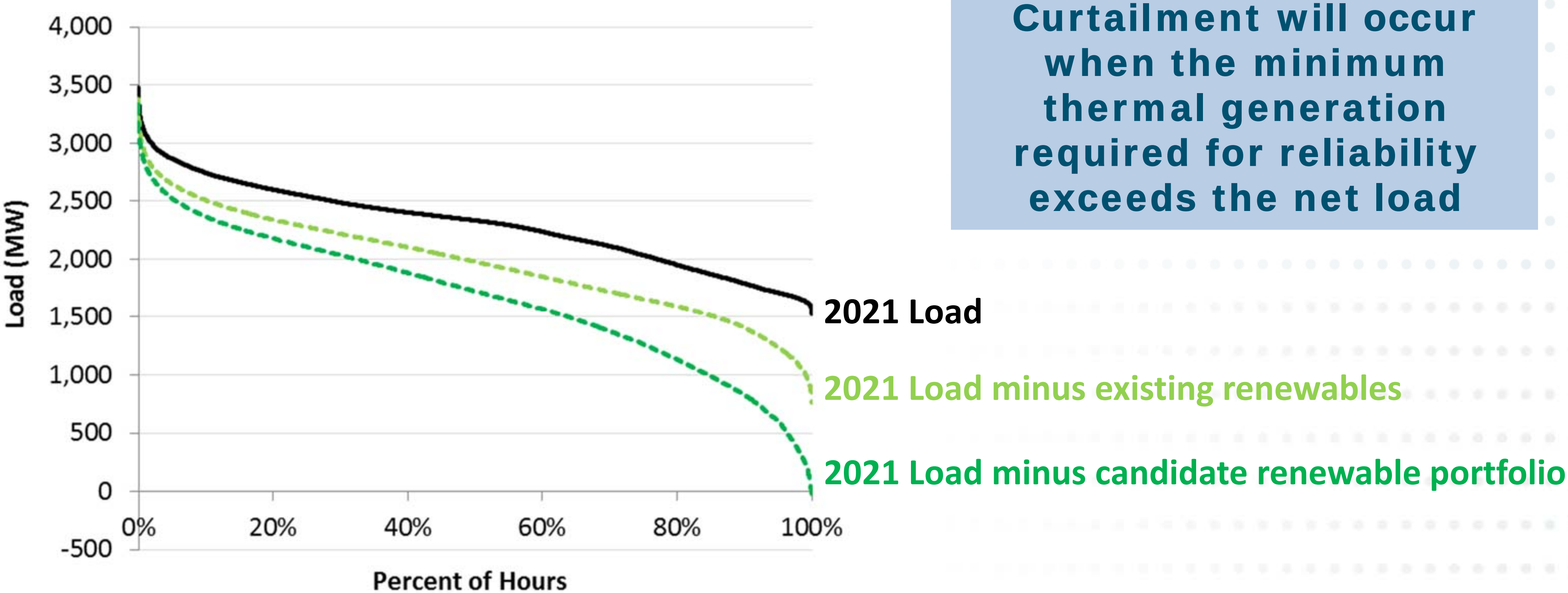
Energy+Environmental Economics

FLEXIBILITY CHALLENGES IN THE PGE SYSTEM

Minimum Generation Challenges

+ Low net load conditions

- May increase cycling of thermal plants
- May require renewable curtailment to ensure system reliability



Curtailment will occur when the minimum thermal generation required for reliability exceeds the net load

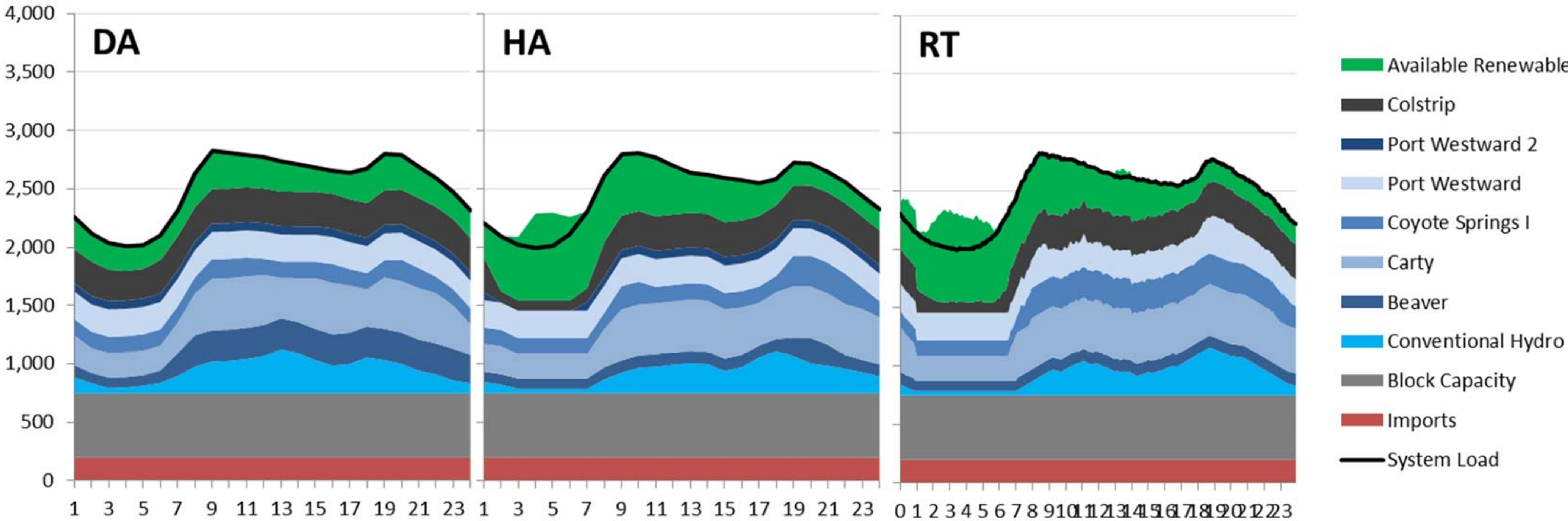
Ramping Challenges

+ **Continued wind development increases the tails of ramping distributions**
  - Existing renewables increase magnitude of most extreme ramp events by factor of 1.3 – 1.5 relative to no renewables
  - Candidate portfolios increase magnitude of extreme ramp events by factor of ~2.5 relative to no renewables

Hourly Ramp Percentiles (MW)	0.1%	1.0%	10.0%	90.0%	99.0%	99.9%
2021 Load Ramps	-487	-239	-141	145	310	373
2021 Net Load Ramps - Existing Renewables	-723	-291	-156	156	333	479
2021 Net Load Ramps - Candidate Renewable Portfolio	-1,274	-425	-176	176	390	915

Example scheduling and dispatch – Existing renewables

- REFLEX models real-time (5-minute) dispatch and day-ahead and hour-ahead unit commitment based on imperfect forecasts
- Example dispatch shown below meets all 2021 capacity needs with entirely inflexible "Block Capacity" resource
- Early morning day-ahead wind forecast error drives curtailment
- Real-time fluctuations managed primarily with gas



Curtailment patterns at higher wind & solar penetrations

Average renewable curtailment by month-hour in 2021

Hour of Day

Existing Renewables

Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	55	75	93	110	116	86	36	8	1	-	-	-	-	-	-	-	0	-	-	-	-	-	2	24
2	23	47	68	73	63	46	19	4	0	-	-	-	-	-	0	0	-	0	-	-	-	-	1	10
3	82	110	116	113	98	62	28	8	3	-	-	-	-	0	1	1	0	1	0	-	-	-	8	34
4	123	148	163	152	108	49	16	8	1	0	-	0	0	1	2	3	2	1	0	1	-	-	8	73
5	121	158	157	155	137	82	27	7	4	1	-	-	-	2	-	0	1	1	-	0	-	-	5	43
6	129	178	207	222	198	151	68	17	4	1	-	-	-	-	-	-	-	-	[illegible]	[illegible]	[illegible]	[illegible]	6	50
7	74	132	166	181	185	158	102	35	10	3	0	-	-	-	-	-	-	-	[illegible]	[illegible]	[illegible]	[illegible]	6	53
8	51	79	108	126	123	97	72	40	12	0	-	-	-	-	-	-	-	-	[illegible]	[illegible]	[illegible]	[illegible]	2	22
9	63	82	112	130	133	101	40	25	11	3	1	0	1	1	0	1	1	-	[illegible]	[illegible]	[illegible]	0	20	65
10	109	131	155	170	137	77	21	7	3	1	-	-	-	-	-	0	-	-	-	[illegible]	[illegible]	3	12	48
11	61	76	95	102	81	56	31	9	2	0	-	-	1	1	1	2	2	0	-	-	[illegible]	-	2	21
12	32	66	92	102	100	79	43	14	2	-	-	-	-	-	0	1	1	-	-	-	[illegible]	-	0	4

Candidate Portfolio

Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	[illegible]	[illegible]	22	23	24
1	207	261	284	306	300	262	179	90	55	37	31	23	23	24	27	29	31	21	4	3	4	8	36	113
2	87	127	157	150	142	137	97	48	27	14	15	15	22	25	24	22	10	7	[illegible]	[illegible]	[illegible]	[illegible]	12	48
3	247	283	281	274	263	214	120	56	32	30	26	28	26	28	29	31	25	19	[illegible]	[illegible]	[illegible]	[illegible]	79	161
4	303	373	406	402	365	268	140	97	89	76	79	93	107	112	114	113	91	77	[illegible]	[illegible]	[illegible]	[illegible]	110	214
5	236	265	263	270	260	221	147	83	69	65	33	23	24	31	17	23	24	27	27	38	36	37	78	155
6	254	301	308	320	300	272	186	93	61	48	37	34	32	27	22	24	26	24	22	23	24	28	53	131
7	89	115	136	147	149	123	81	33	14	4	[illegible]	-	-	-	-	0	1	1	2	6	12	18	34	96
8	91	114	137	149	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	3	4	3	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	1	6	24	55
9	127	140	154	170	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	31	26	23	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	4	18	40	96	153
10	178	207	238	260	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	2	3	4	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	5	8	19	41	81
11	145	176	198	197	173	142	108	66	47	34	16	19	24	20	21	21	17	9	1	5	7	22	47	82
12	118	175	209	224	233	207	155	81	32	18	15	11	14	18	23	23	20	12	6	9	12	14	23	34

Exacerbates nighttime curtailment

Introduces daytime curtailment

Completed Work and Next Steps

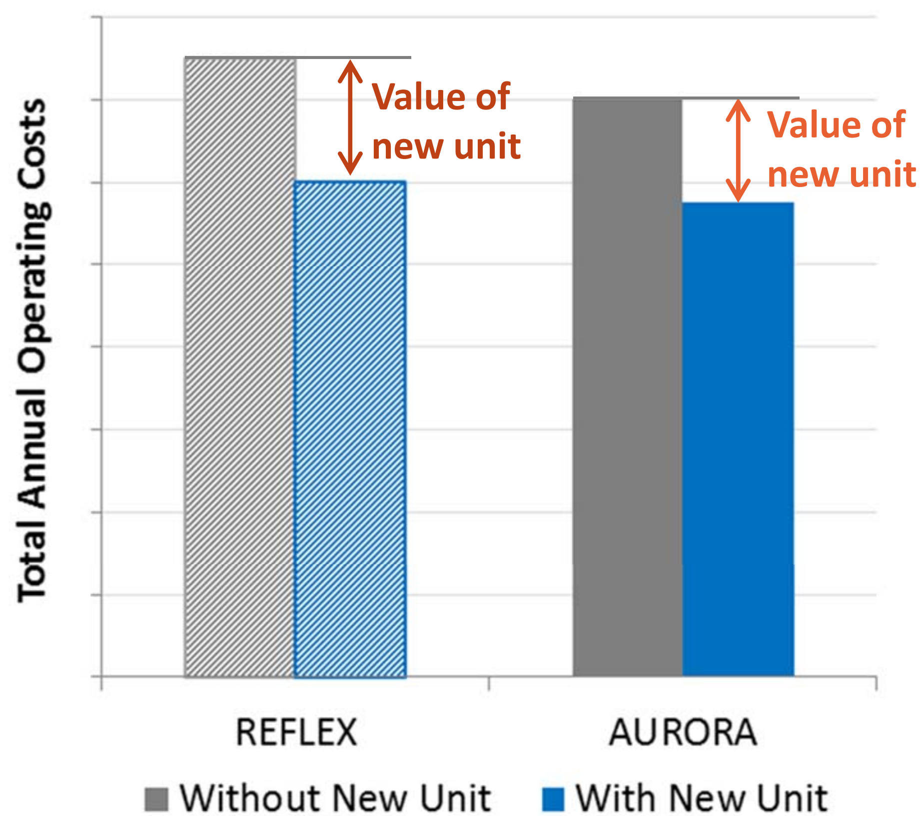
+ **Develop REFLEX cases for several renewable portfolios**
  - ✓ PGE loads and resources
  - ✓ PGE hydro conditions
  - ✓ Colstrip dispatch behavior
  - ✓ On-peak/off-peak import treatment
+ **Quantify flexibility challenges**
  - ✓ Simulate dispatch and quantify curtailment with inflexible “Block Capacity”
+ **Assess flexibility solutions**
  - ❑ Simulate dispatch and quantify curtailment with candidate resources

Incorporation into PGE IRP process

- **Metrics from REFLEX can be used to supplement outputs from AURORA**
  - Example: REFLEX models constraints related to starts and stops that are not well resolved by planning models
  - A unit that can quickly and cheaply start and stop might provide additional value not captured by AURORA
- **E3 will test candidate resources in REFLEX in parallel to PGE's AURORA modeling**

Example (not to scale below):

Value adder in AURORA =
[Unit value in REFLEX w/ all constraints] –
[Unit value in REFLEX w/o flexibility constraints]



Thank You!

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UM 1719 – Capacity Contribution of VER

- August 17th workshop with Commissioners that will include presentations from three noted experts in renewable capacity contribution studies.
  - Andrew Mills – Lawrence Berkeley National Laboratory
    - Findings from "An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes" which discusses Load Serving Entity's approaches towards capacity planning and the differences in valuation of solar capacity among several utilities.
  - Michael Milligan – National Renewable Energy Laboratory
    - Summarizing the findings from the NERC report "Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning" for which Mr. Milligan was the team lead.
  - John Fazio – Northwest Power & Conservation Council
    - Focus on findings from his work with the Northwest Power and Conservation Council Power Committee, with an emphasis on methods for estimating capacity of wind generation. Mr. Fazio may also address BPA's approach to estimating wind capacity.
- The rest of the schedule will be established after the August 17th workshop.
- http://apps.puc.state.or.us/edockets/docket.asp?DocketID=19443

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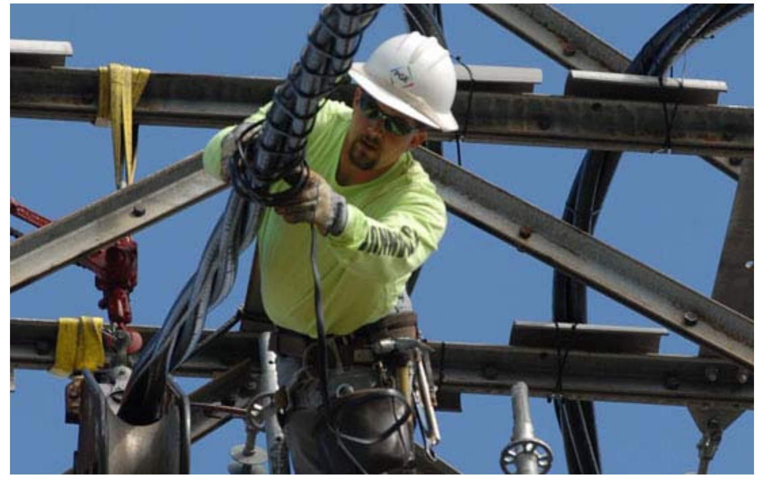

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Demand Response Update

Purpose of Today's Discussion

Start a dialogue about how PGE will consider Demand Response and Dynamic Pricing in the 2016 IRP:

- Discuss projects in the field
- Share pilots in development
- Share the results of the 2015 DR Potential Study

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Dynamic Pricing & Demand Response Efforts

Ongoing:

- Time of Use
- Demand Buyback
- Schedule 77 Load Curtailment
- Energy Partner^{SM} Automated Demand Response Pilot

New for 2015:

- Residential Dynamic Pricing Pilot
- Residential Direct Load Control Pilot

Completed:

- Flex Price^{SM} Critical Peak Pricing Pilot (Sch. 12)
- Transactive Node Water Heater Demand Response Pilot

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Pricing Pilot Overview

- Two-year Behavioral Demand Response and Dynamic Pricing pilot
- Winter and summer programs
- Pilot tests two approaches
  - New time-of-use (TOU) rates
  - Peak time rebates (PTR) event based incentives

	Control Group	Schedule 7 Informed	Day and Night TOU	Peak only TOU	Revised TOU
Without PTR (# of Cust)	X	X	X	X	X
With PTR (# of Cust)		X	X	X	X
Tentative Hours	No Change	No Change	Day: 6am-10pm Night: 10pm-6am	High:7am-10am / 3pm-8pm Low: All other time	High:7am-10am / 3pm-8pm Mid: 10am-3pm Off: 8pm to 7am

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2015 Smart Thermostat Pilot Overview

- Uses residential, programmable, communicating ("smart") thermostats for automated demand response under a **bring-your-own-thermostat** structure

- Participants receive an incentive payment for each event season

- Two-year pilot will enroll up to 5,000 customers

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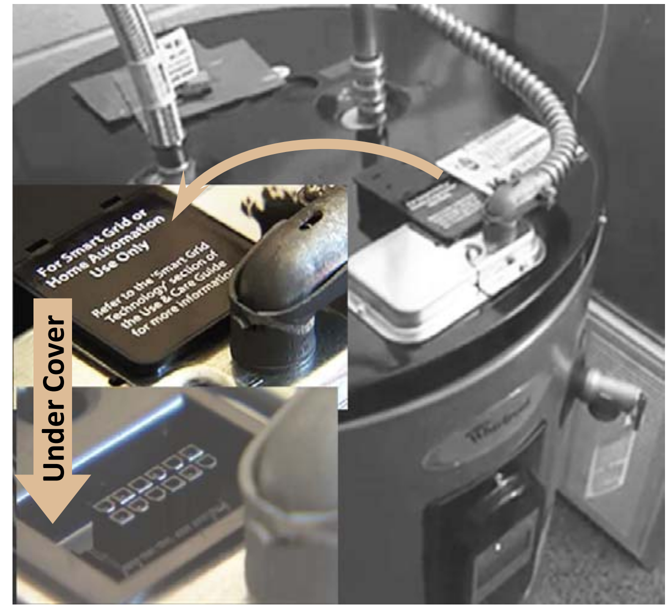
Smart Water Heater Pilot

- Investigates the market readiness and potential value of CEA-2045 enabled “smart” water heaters.

- BPA funded three-year project
  - 600 water heaters spread across multiple NW utilities
  - 2017-2020

- Can help unlock opportunities for use of standardized “socket” on several energy-using devices.



Questions

August 13, 2015 Slide 95

Portland General Electric's Demand Response Potential

August 2015 Stakeholder Presentation

PREPARED FOR

Portland General Electric

PREPARED BY

Ryan Hledik
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August 2015

THE Brattle GROUP

Acknowledgements

We would like to acknowledge the contributions of Ingrid Rohmund, Dave Costenaro, Sharon Yoshida, and Bridget Kester of Applied Energy Group. They led the market data collection and program cost development in this study.

We would also like to thank the PGE team including Josh Keeling, the project manager, and Joe Keller, Jimmy Lindsay, Mihir Desu, Conrad Eustis, and Rick Durst for their responsiveness to our questions and for their valuable insights.

Opinions expressed in this presentation, as well as any errors or omissions, are the authors' alone. The examples, facts, results, and requirements summarized in this report represent our interpretations. Nothing herein is intended to provide a legal opinion.

In this presentation...

We estimate the peak reduction capability that could be achieved through the deployment of demand response (DR) programs in PGE's service territory

We also assess the cost-effectiveness of each DR option based on a comparison of program costs to avoided resource costs

The findings will help guide the integrated resource planning (IRP) team's assumptions about future DR impacts

The study analyzes “maximum achievable potential”

Assumes enrollment rates reach levels of successful DR programs around the country

Several factors suggest that PGE’s customer base could reach these levels of participation

- Success with energy efficiency programs
- Environmentally conscious customer base
- Rising adoption of energy management products (e.g., smart thermostats)
- Growing summer peak demand

Since PGE is starting from a point of relatively limited experience with DR, it will likely take time to reach these levels of participation

- This has been the experience with the Energy Partner program

28 different options are analyzed

	Residential	Small C&I (<30 kW)	Medium C&I (30 to 200 kW)	Large C&I (> 200 kW)	Agricultural
Pricing Options					
Time-of-use (TOU)	X	X			X
Peak Time Rebate (PTR)	X	X			
PTR w/tech	X	X			
Critical Peak Pricing (CPP)	X	X	X	X	
CPP w/tech	X	X	X	X	
Conventional Non-pricing Options					
Direct load control (heating/cooling)	X	X			
Direct load control (water heating)	X	X			
Curtailable tariff			X	X	
Third-party DLC			X	X	X
Emerging DR Options					
Bring-your-own-thermostat (BYOT)	X				
Electric Vehicle (EV) charging load control	X				
Smart water heating	X				
Behavioral DR	X				

Not all customer segments are eligible for each DR option

Participation rates

Pricing options

- Based on review of market research studies and full-scale deployments
- Opt-in participation ranges from **13% to 28%**
- Opt-out participation ranges from **63% to 92%**
- Varies by rate option and customer class

Conventional non-pricing options

- Largely based on 75^{th} percentile of observed enrollment in full-scale programs
- Participation can range from **15% to 25%**
- Higher enrollment observed in Large C&I curtailable tariff (**40%**)

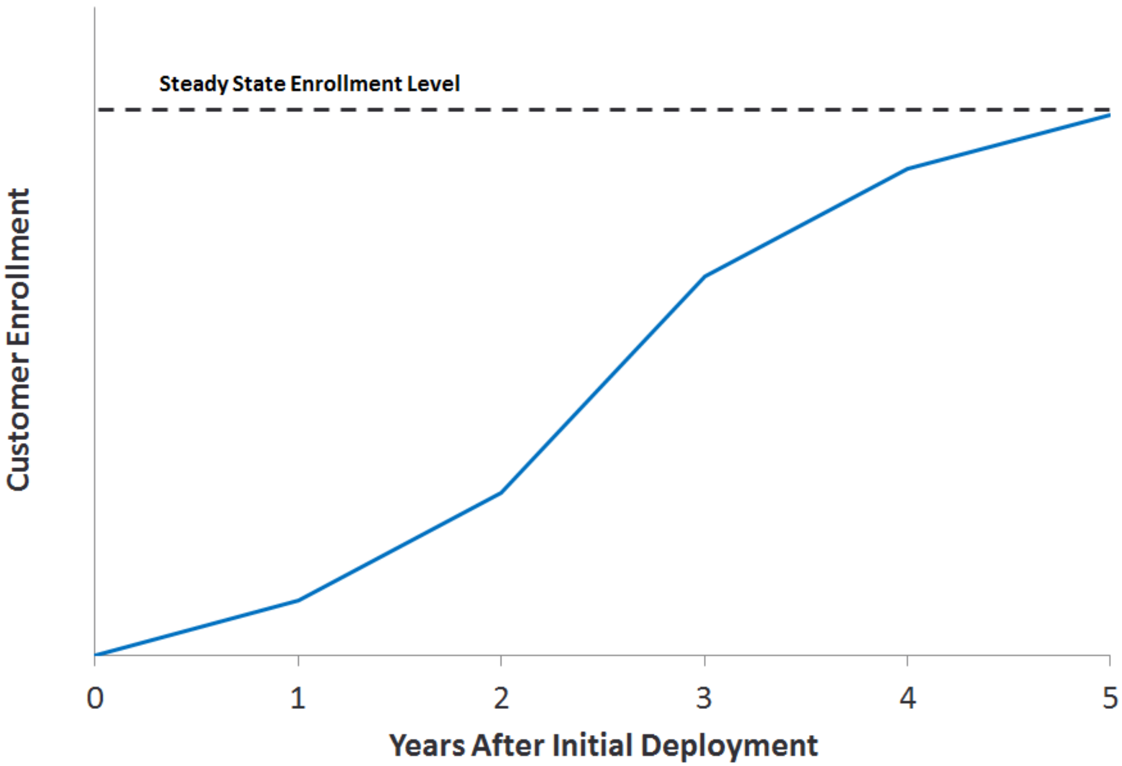
Emerging DR options

- Draws upon experience of pilot programs where available
- Intuition-based "what if" scenarios used where market data is not available

See Appendix A for additional detail

We account for a multi-year transition to the steady state enrollment levels

Illustration of S-Shaped Diffusion Curve



Comments

- Changes in participation are assumed to happen over a 5-year timeframe once the new programs are offered
- The ramp up to steady state participation follows an "S-shaped" diffusion curve, in which the rate of participation growth accelerates over the first half of the 5-year period, and then slows over the second half
- A similar (inverse) S-shaped diffusion curve is used to account for the rate at which customers opt-out of default rate options
- This reflects an aggressive ramp-up in participation for a utility with relatively limited DR experience like PGE

Load impacts per participant

Pricing options

- Based on impacts observed in 225 pricing tests in past 12 years
- Accounts for differences across rate design, season, and offering
- Response is a function of peak-to-off-peak price ratio
- Price ratios based on PGE designs: TOU is 2:1, CPP is 4:1, PTR is 8:1

Conventional non-pricing options

- Based on review of 10 DR studies conducted in Pacific Northwest
- Supplemented with observed impacts from other U.S. DR programs

Emerging DR options

- Based on findings of pilots where applicable
- Calibrated to other DR options to ensure reasonable relative impacts across programs

See Appendix B for additional detail

Important adjustments are made to the benefit and cost assumptions in the cost-effectiveness analysis

Avoided costs are derated

- Avoided capacity costs are derated by between 19% and 47%
- Accounts for operational limitations of the DR programs
- For example, limitations on number of events per year or hours of the day when the program can be dispatched
- Derate factors are based on values established by California utilities and adjusted as needed to better represent programs analyzed for PGE

Incentives are reduced as a cost

- Only 50% of incentive payment is counted as a cost
- Roughly represents loss of comfort/service to customer (i.e. "hassle factor")
- We test sensitivity cases at 100% and 0%

See Appendix D for additional detail

Important caveats

- The load reduction potential and cost-effectiveness of each DR option are evaluated in isolation from the other options; the potential estimates are not additive and economics may change when the DR options are offered as part of a portfolio

- Our analysis is based on "typical" program designs with illustrative incentive payments. Rather than being the final word on the cost-effectiveness of these programs, our findings should be used as a starting point for further exploring how different program designs would change the economic attractiveness of the programs

- Unless otherwise noted, peak reduction potential estimates are reported for the year 2021, the first year in which PGE is projected to need new capacity and when the Boardman plant will retire

The remainder of this presentation is organized around 9 key findings

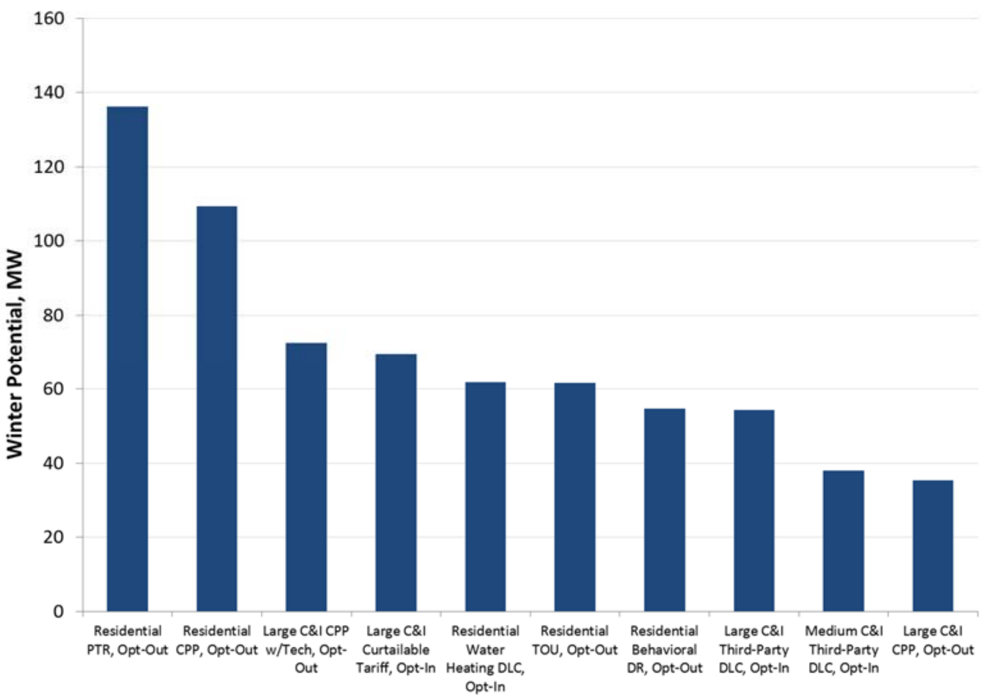
1. The most attractive DR opportunities are in the residential and large C&I customer segments
2. Residential pricing programs present a large and cost-effective opportunity to leverage the value of PGE's AMI investment
3. The incremental benefits of coupling enabling technology with pricing options are modest and perhaps best realized through a BYOT program
4. BYOT programs offer better economics than conventional DLC programs but lower potential in the short- to medium-term
5. Residential water heating load control is an attractive opportunity with a broad range of potential benefits
6. Small C&I DLC has a small amount of cost-effective potential
7. DR is highly cost-effective for large and medium C&I customers and the potential can be realized through a number of programs
8. Agricultural DR programs are small and uneconomic
9. The economics of some programs improve when accounting for their ability to provide ancillary services

Finding #1:

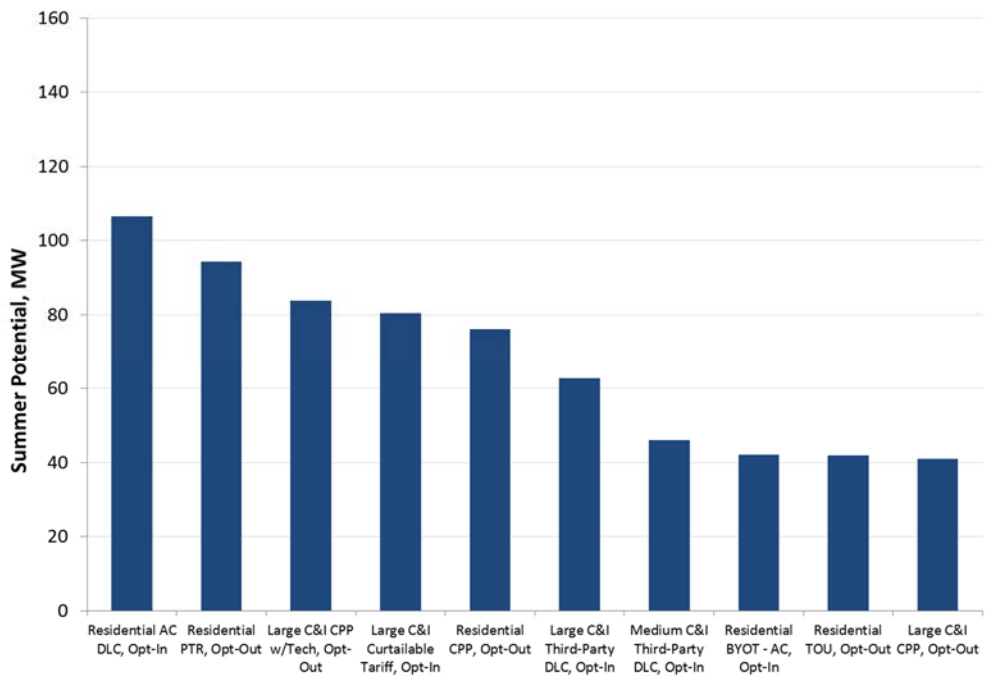
The most attractive DR opportunities are in the residential and large C&I customer segments

The top 10 measures in terms of potential

Winter Potential



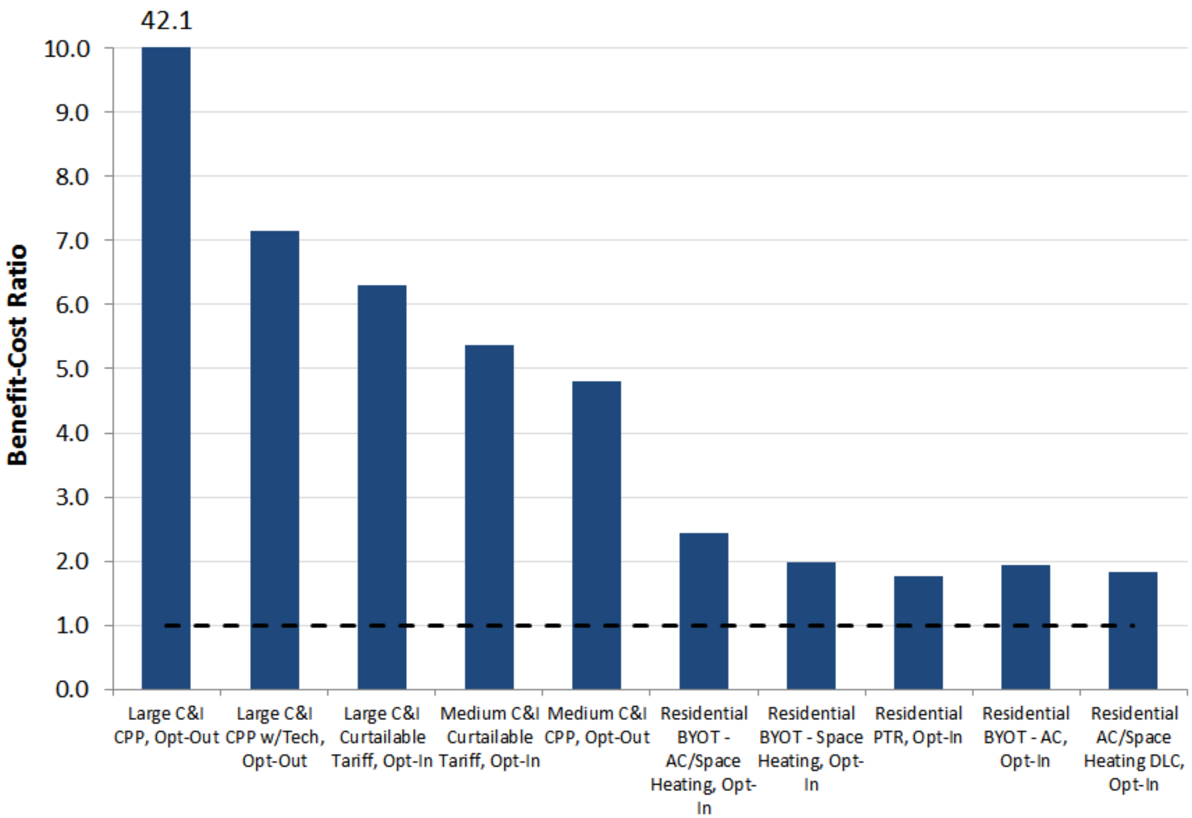
Summer Potential



- The largest programs are in the industrial and residential sectors
- Opt-out dynamic pricing generally provides the largest aggregate impacts due to high expected enrollment rates

The top 10 measures in terms of cost-effectiveness

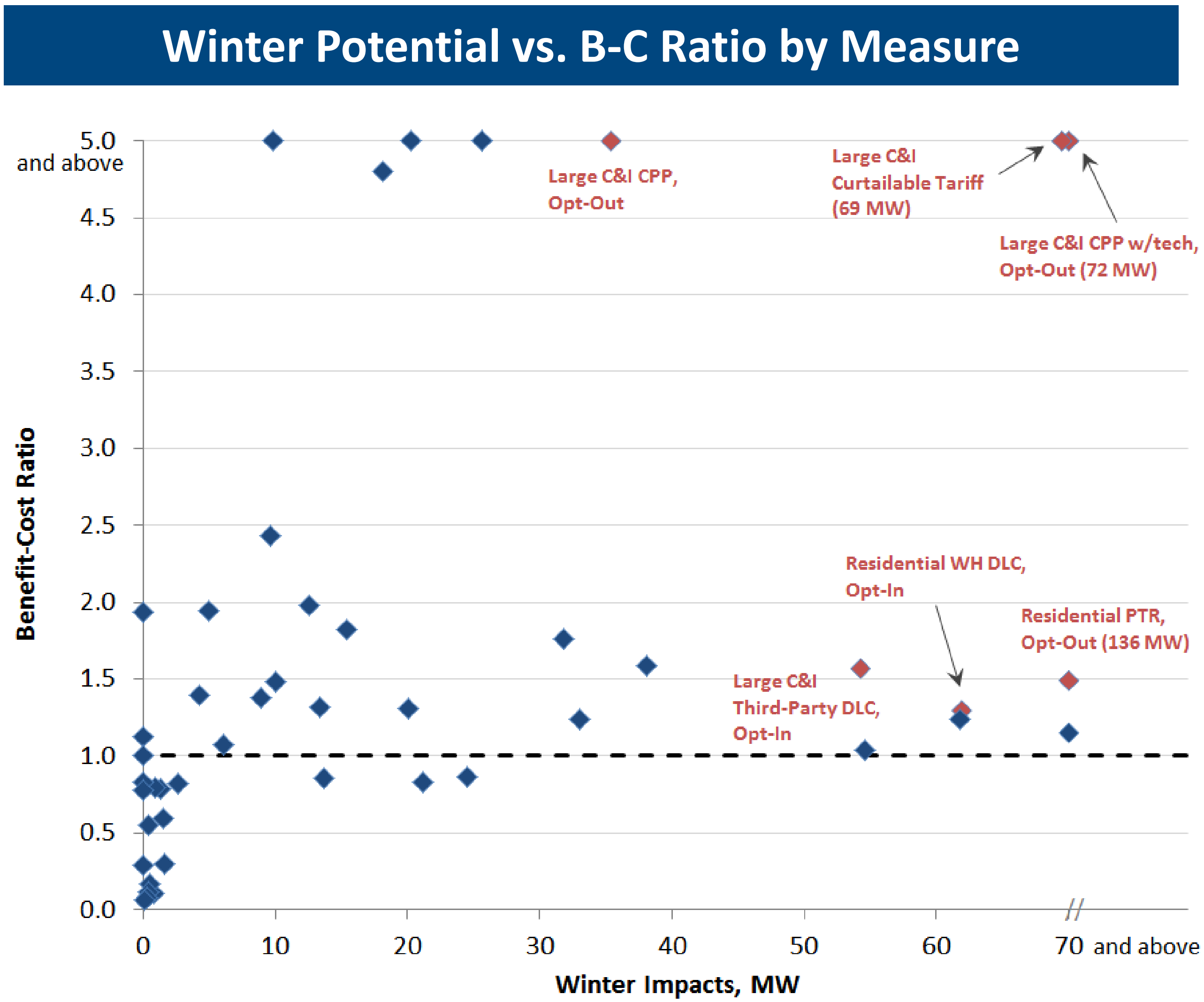
Benefit-Cost Ratios



Comments

- Several large C&I and residential programs are highly cost-effective
- The most cost-effective programs tend to be pricing programs and curtailable tariffs

The programs with the biggest "bang for the buck" are in the residential and large C&I classes



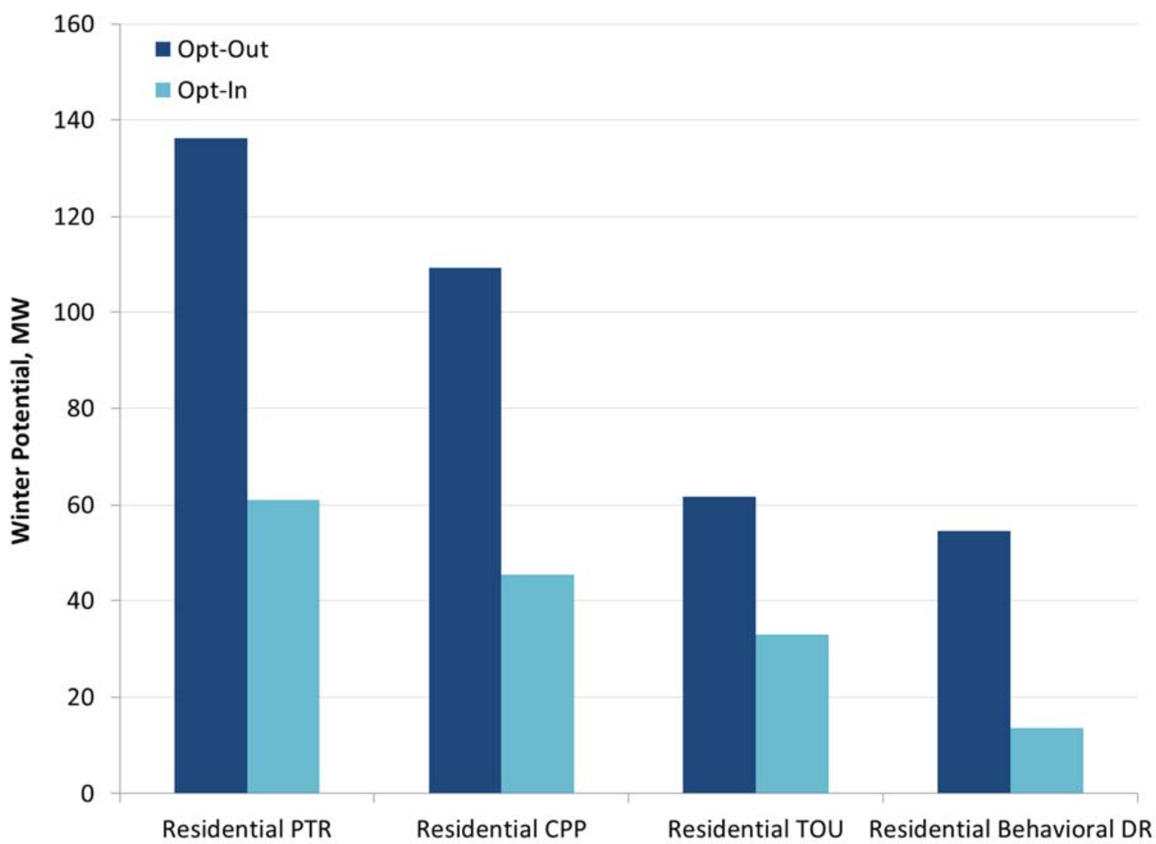
The highlighted programs provide large, highly cost-effective DR potential

Finding #2:

Residential pricing programs present a large and cost-effective opportunity to leverage the value of PGE's AMI investment

Residential pricing programs have significantly higher potential if deployed on an opt-out basis

Winter Potential – Residential Pricing & BDR



Comments

- Opt-out deployment leads to aggregate peak reduction capability that is between 90% and 300% higher than an opt-in deployment
- While PTR is likely to produce smaller per-customer impacts than CPP, the potential for higher enrollment leads to larger aggregate impacts
- Note that these impacts are in the absence of any enabling technology

Residential pricing programs are cost-effective

Cost-Effectiveness – Residential Pricing & BDR

Comments

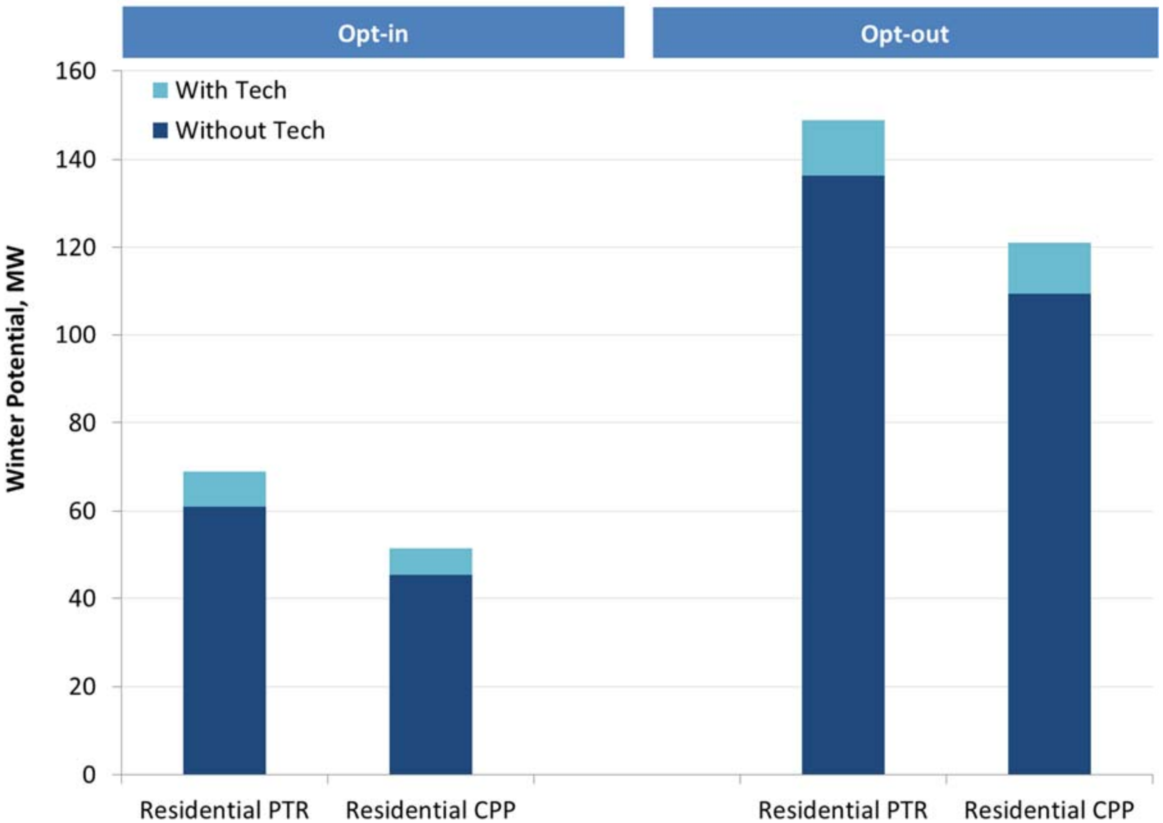
- For conventional pricing programs the opt-in offering has a slightly higher benefit-cost ratio than the opt-out offering due to marketing and education costs that are lower on a dollars-per-kW basis; however, opt-out offerings provide greater net benefits in absolute dollar terms
- Note that behavioral DR is assumed to be offered in the absence of any technology (event notification would be provided by text, email, etc.); enabling technology would change the economics of the program

Finding #3:

The incremental benefits of coupling enabling technology with residential pricing options are modest and perhaps best realized through a BYOT program

The provision of enabling technology modestly increases price response in the aggregate

Winter Potential – Residential Pricing with Tech

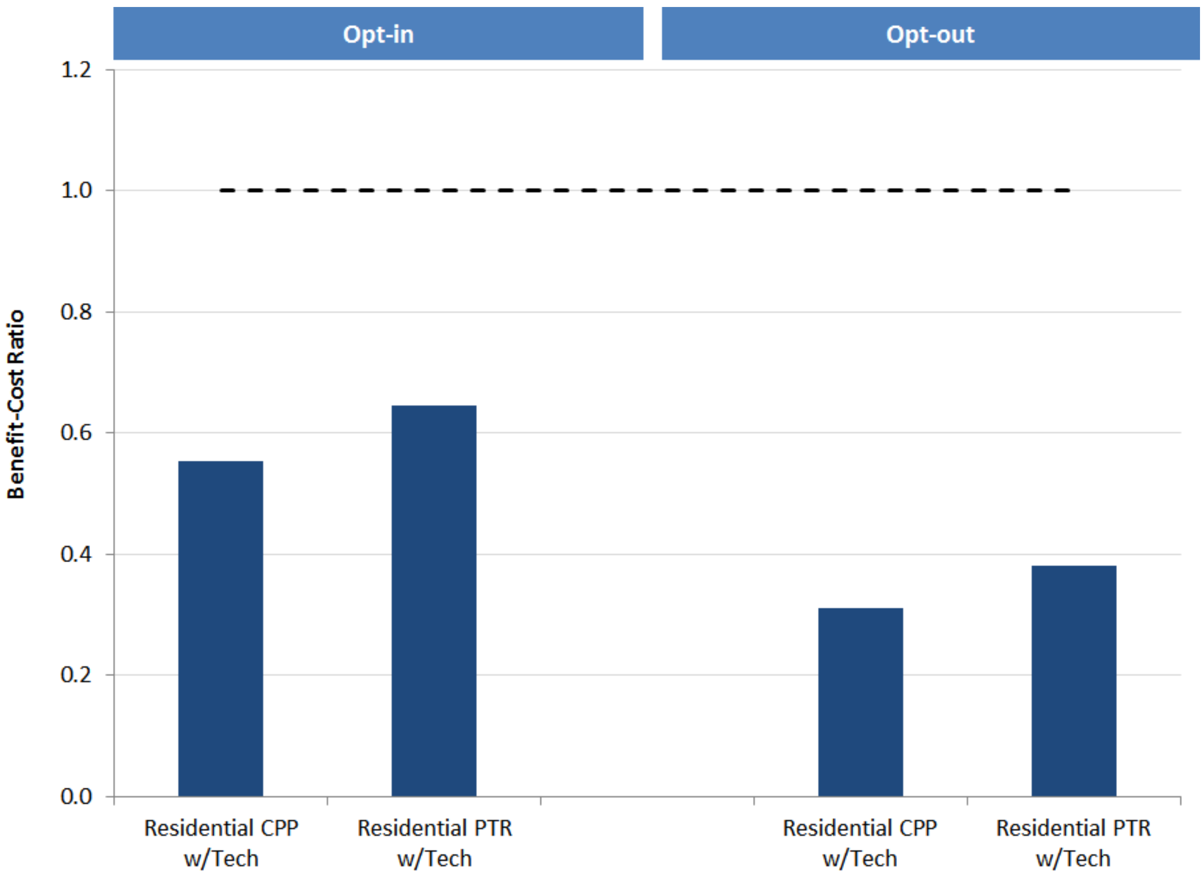


Comments

- The incremental impact of enabling technology provides a 90% boost over the impact of price alone among those equipped with the technology
- We have assumed that only customers with both electric heat and central A/C would be eligible for pricing with enabling technology, as these are the only segment for which it is likely to be cost-effective
- Since less than 10% of residential customers have both electric heat and central A/C, the aggregate impact of enabling technology is fairly limited

The cost-effectiveness of enabling technology coupled with price is questionable

Cost-effectiveness – Residential Pricing with Tech



Comments

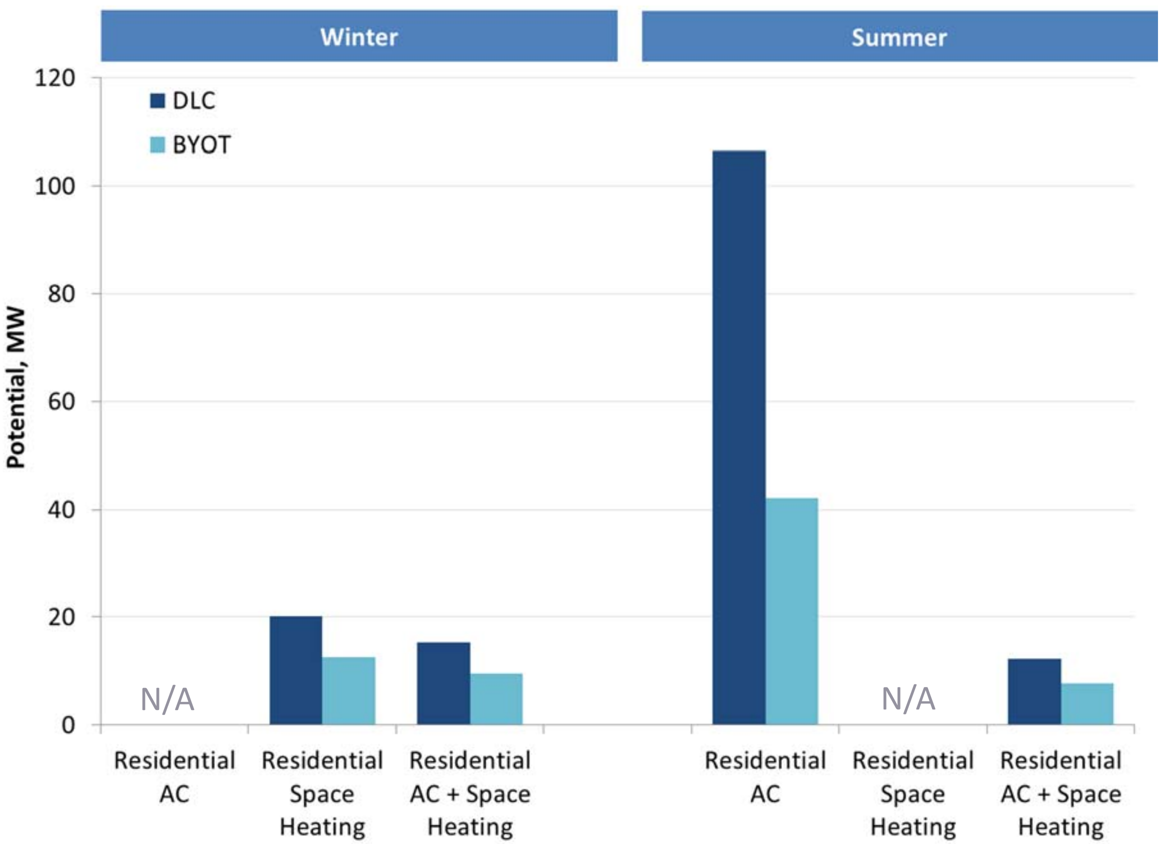
- Assuming there is already a plan to roll out dynamic pricing, the incremental impact of enabling technology, above and beyond the impact that would be achieved in the absence of the technology, is not enough to justify the cost, even in the absence of program administration costs (as shown at left)
- This is a different outcome from most other jurisdictions, where a summer peak and significant air-conditioning market penetration can justify the investment
- Where customers already own a smart thermostat a BYOT program coupled with a dynamic pricing program could make sense
- There may also be additional value in a “prices-to-devices” concept with real-time pricing and end-uses that provide automated response to changes in the price with short notification

Finding #4:

BYOT programs offer better economics than conventional DLC programs but lower potential in the short- to medium-term

Residential DLC is a potentially large summer resource

Seasonal Potential – Residential DLC

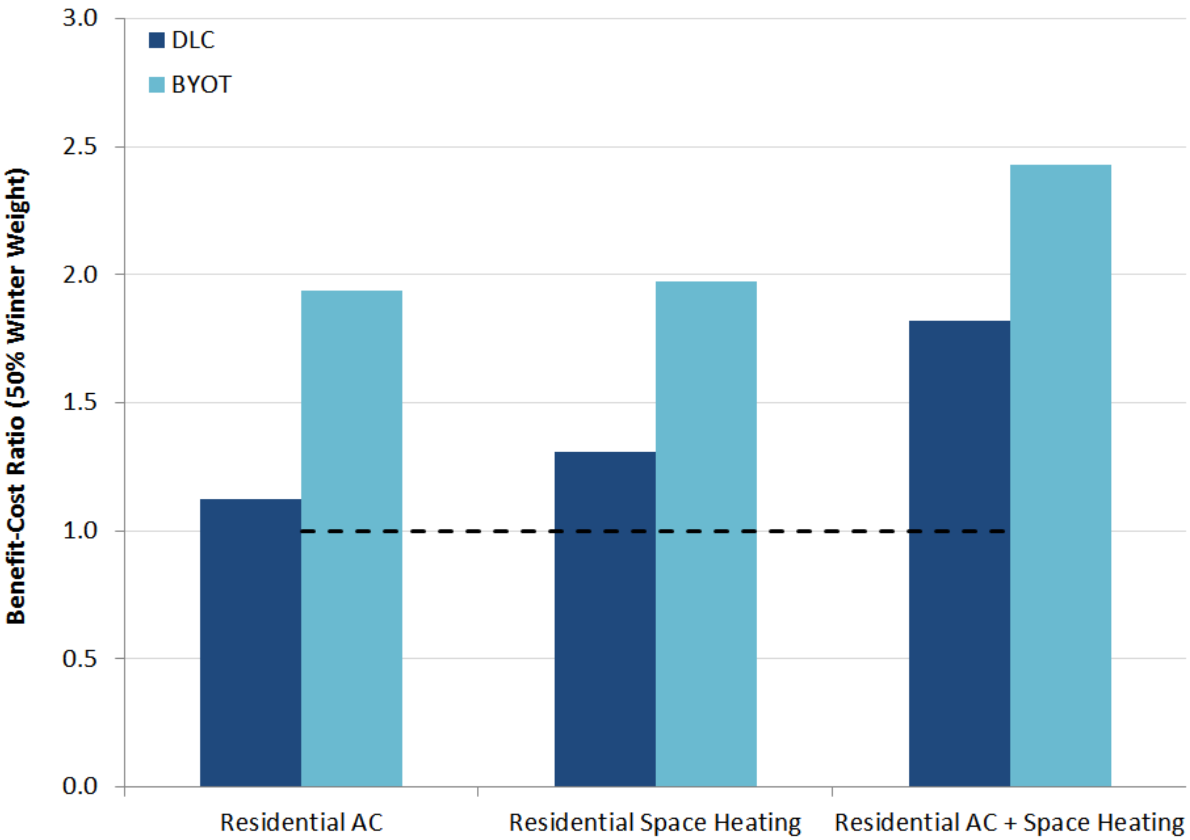


Comments

- DLC produces larger aggregate impacts than BYOT because more customers are eligible to participate
- A/C load control has by far the largest demand reduction potential

Under expected system peaking conditions, all DLC options are cost-effective

Cost-effectiveness – Residential DLC

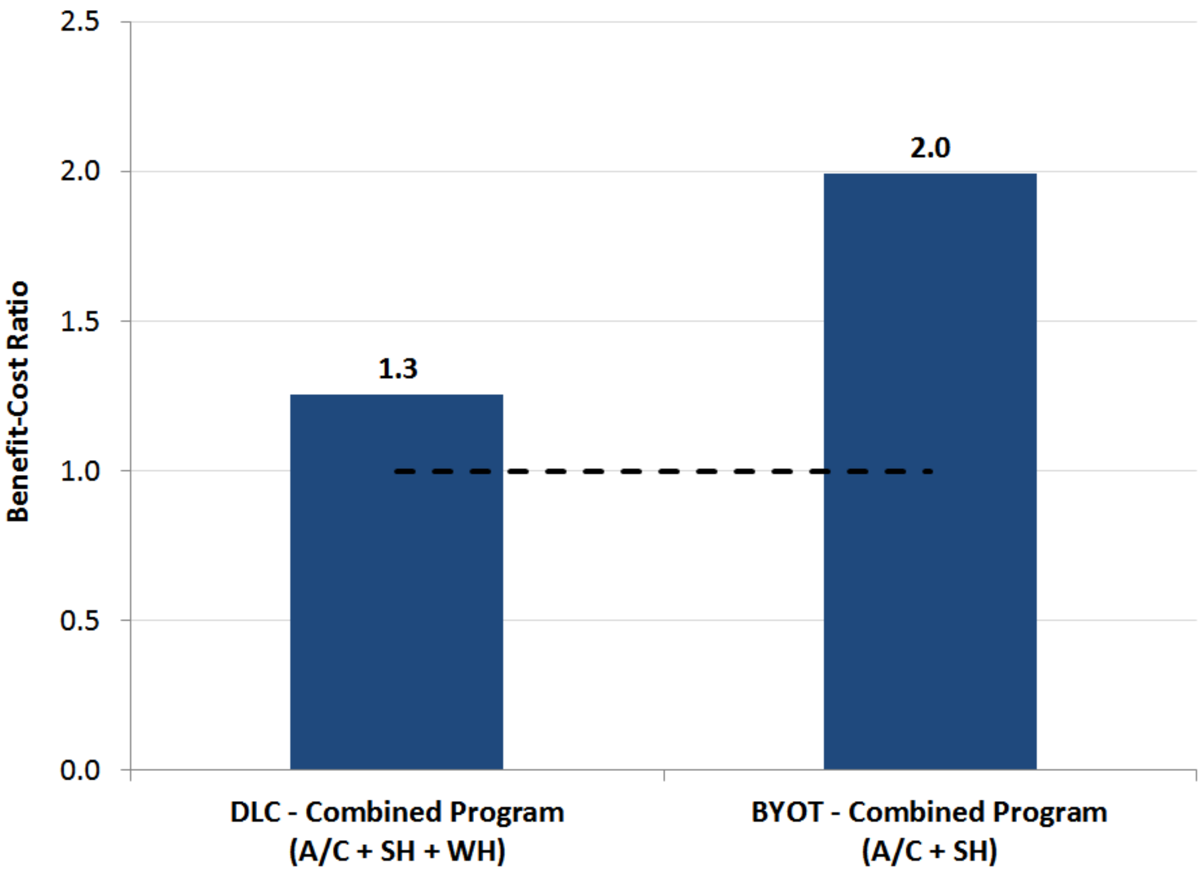


Comments

- BYOT programs offer better cost savings than conventional DLC because there is no associated equipment cost
- Conventional air-conditioning DLC will become increasingly cost-effective as summer peak capacity needs escalate in PGE’s service territory

When offered as a package targeting multiple end-uses, DLC passes the cost-effectiveness screen

Cost-effectiveness – Combined DLC Program



Comments

- Since the DLC program would likely be offered to target multiple end uses, it makes sense to consider the cost-effectiveness of the program in the aggregate
- Both the conventional DLC and BYOT programs are cost-effective in this case
- If electric vehicle home charging load control were added to the portfolio, the program would still be cost-effective, with a total benefit-cost ratio of around 1.2

Finding #5:

Residential water heating load control is an attractive opportunity with a broad range of potential benefits

Two types of water heating load control programs were modeled

Conventional water heating DLC

- Control technology retrofit on existing or new electric water heaters
- Equipment + installation = $300 per participant

"Smart" water heating DLC

- Assumes "DR-ready" electric water heaters gain growing market share
- Equipment + installation = $40 per participant (communications module)
- Incremental manufacturing cost for DR capability = $25 per participant

Water heating load control can provide benefits beyond reductions in the system peak

Benefits will vary depending on the load control strategy and the characteristics of the electric water heater

Ancillary services

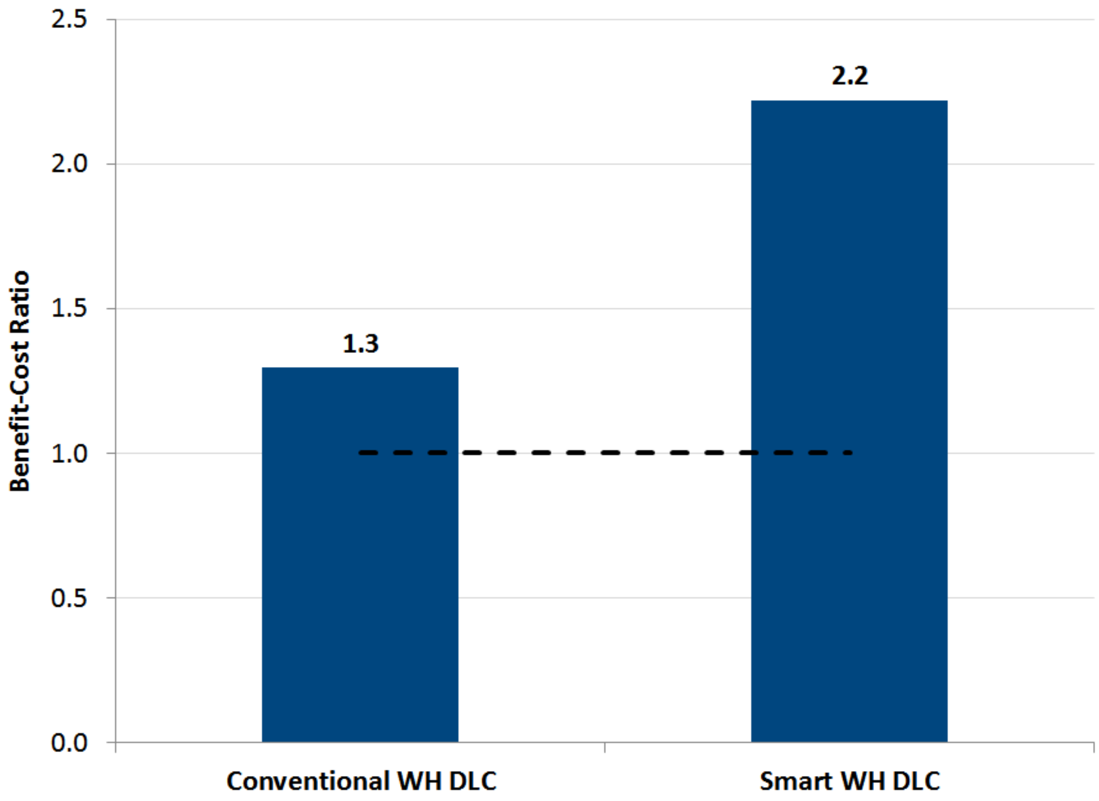
- If equipped with the appropriate control technology, electric resistance water heaters can provide significant increases and decreases in average load with very little notification, making them an ideal candidate to offer ancillary services
- The potential to increase load for short durations of time is higher than the load reduction capability reported on the previous slide by a factor of 4x to 8x

Thermal energy storage

- Large tanks equipped with a mixing valve can super-heat the water at night and then require little to no additional heating during the day
- This would be beneficial in a situation where the marginal cost of generating electricity is low or even negative at night (e.g., large amounts of nighttime wind generation coupled with inflexible base load capacity) or when energy prices are high during the day; it provides an energy arbitrage opportunity
- The potential to provide this type of energy price arbitrage is highly dependent on the size of the water heater and the number of hours over which the load shifting is occurring

Both forms of water heating load control are cost-effective based on avoided peak capacity costs

Cost-effectiveness – Water Heating Load Control



Comments

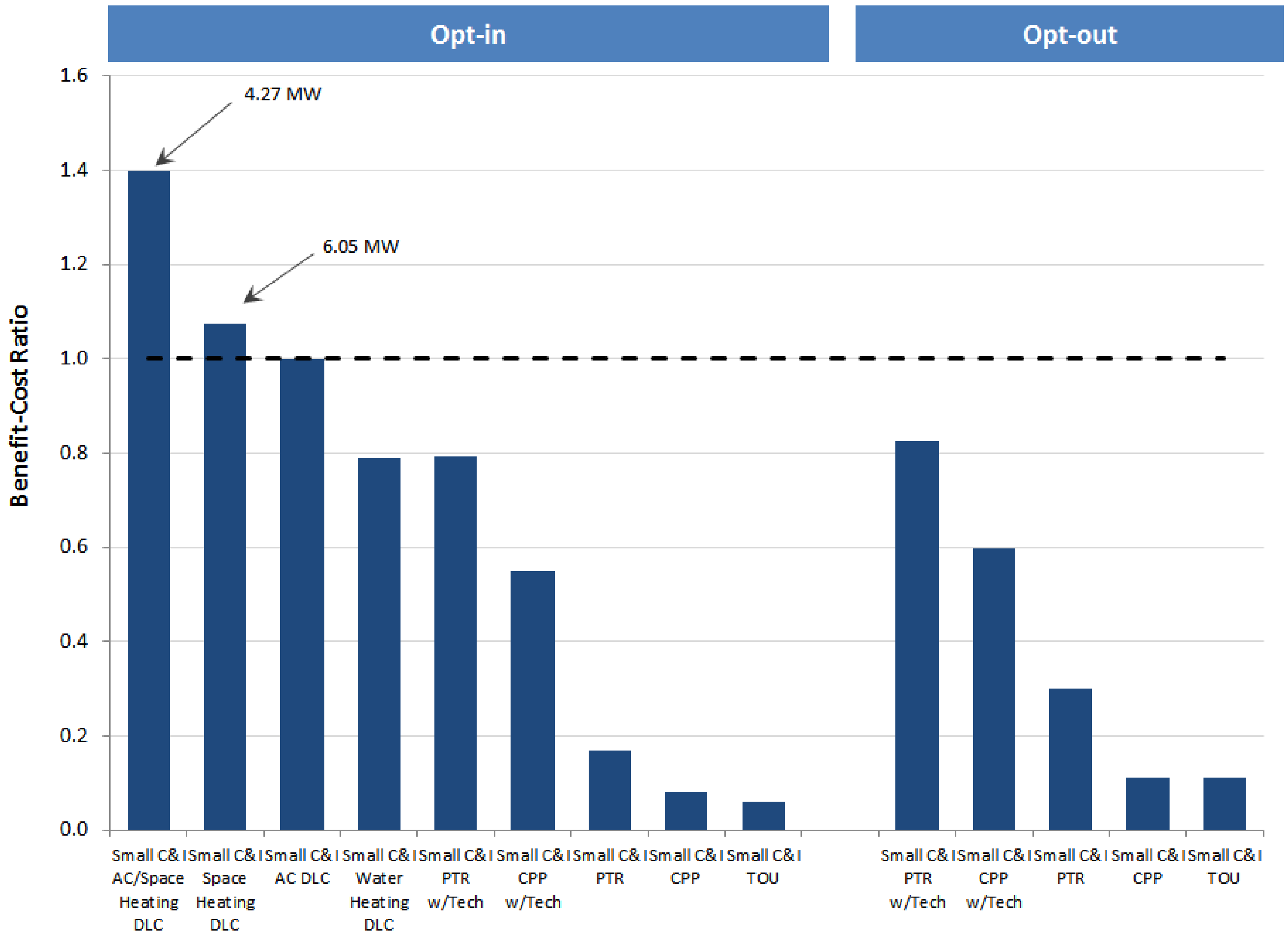
- DR-ready water heaters offer a number of cost saving opportunities relative to conventional DLC, primarily in the form of reduced equipment and installation costs
- "Smart" water heaters will also incorporate more sophisticated load control algorithms that provide harder-to-quantify benefits
- These algorithms could facilitate larger load reductions than a conventional on/off switch in the long run by anticipating the water heating needs of the owner and responding accordingly
- This technology could also reduce the risk of insufficient hot water supply following a DR event relative to the conventional technology
- Additional financial benefit could be realized through both programs by providing increases and decreases in average load with short notification in response to fluctuations in electricity supply

Finding #6:

Small C&I DLC has a small amount of cost-effective potential

Only space heating DLC is cost-effective for the small C&I segment and its potential is small

Cost-effectiveness – All Small C&I DR Options



Comments

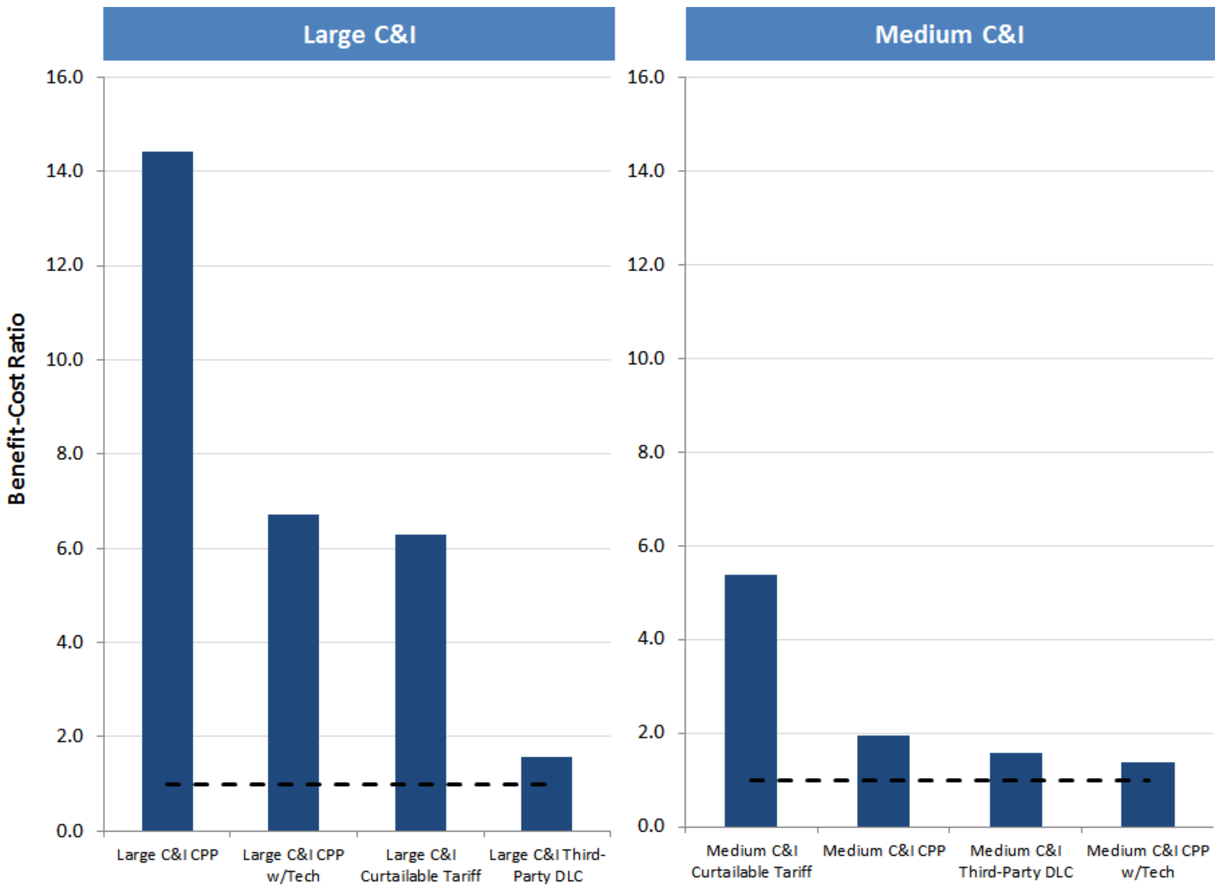
- Space heating DLC is cost-effective for the small C&I segment; winter potential is around 6 MW
- Small C&I customers tend to be unresponsive to time-varying rates unless equipped with enabling technology
- Generally, electricity costs are a small share of the operating budget for these customers and they lack sophisticated energy management systems

Finding #7:

DR is highly cost-effective for large and medium C&I customers and the potential can be realized through a variety of programs

All DR measures are cost-effective for medium and large C&I customers

Cost-effectiveness – Medium and Large C&I



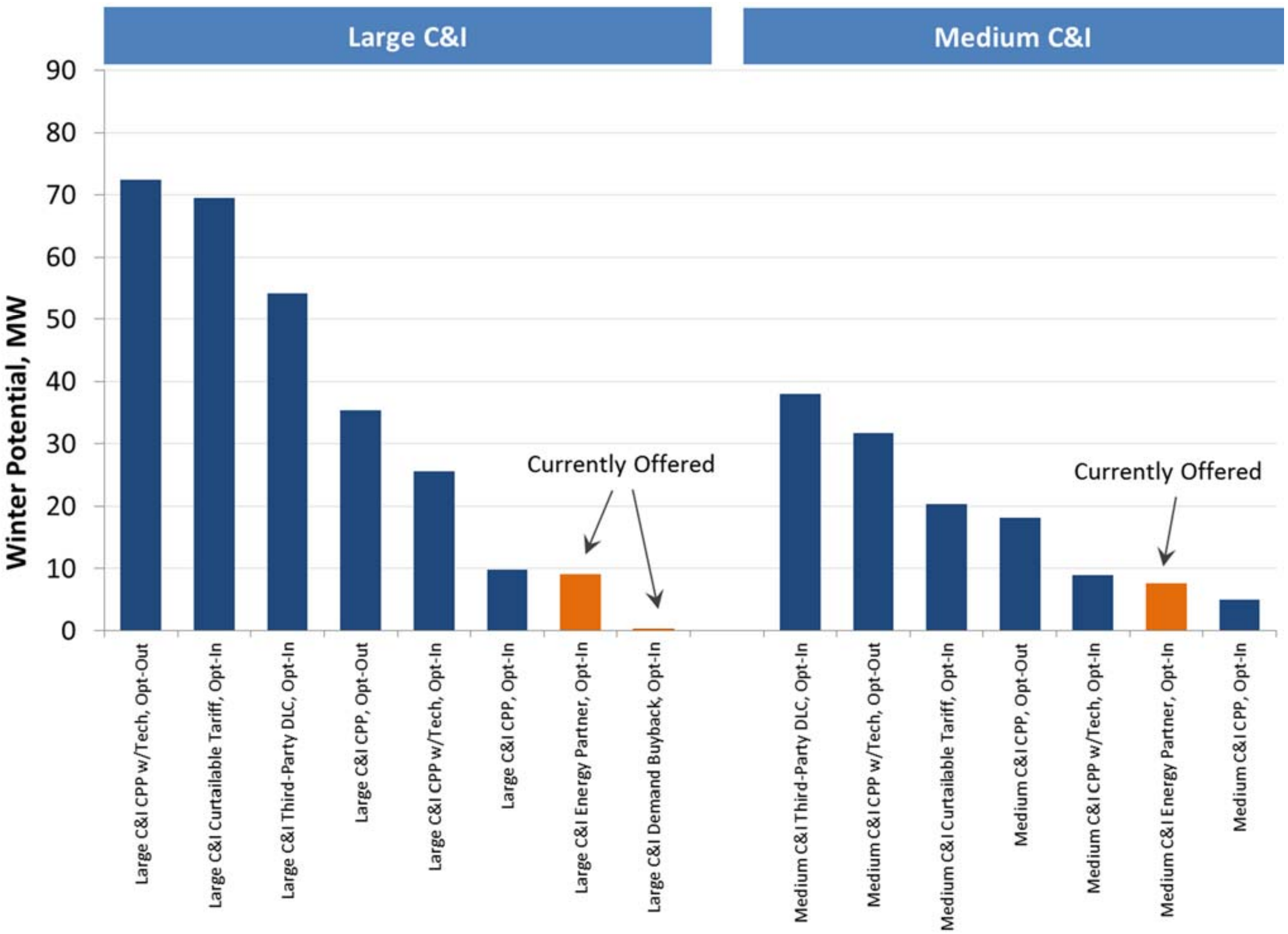
Note: Pricing impacts are shown for opt-in deployment; opt-out deployment is also cost-effective

Comments

- Customer acquisition costs tend to be lower on a dollars-per-kilowatt basis for these segments, leading to attractive economics for DR
- The large C&I segment accounts for the majority of the DR market in other regions of the U.S. for this reason

In addition to being highly cost-effective, several large/medium C&I programs have large potential

Winter Potential – Large and Medium C&I



Comments

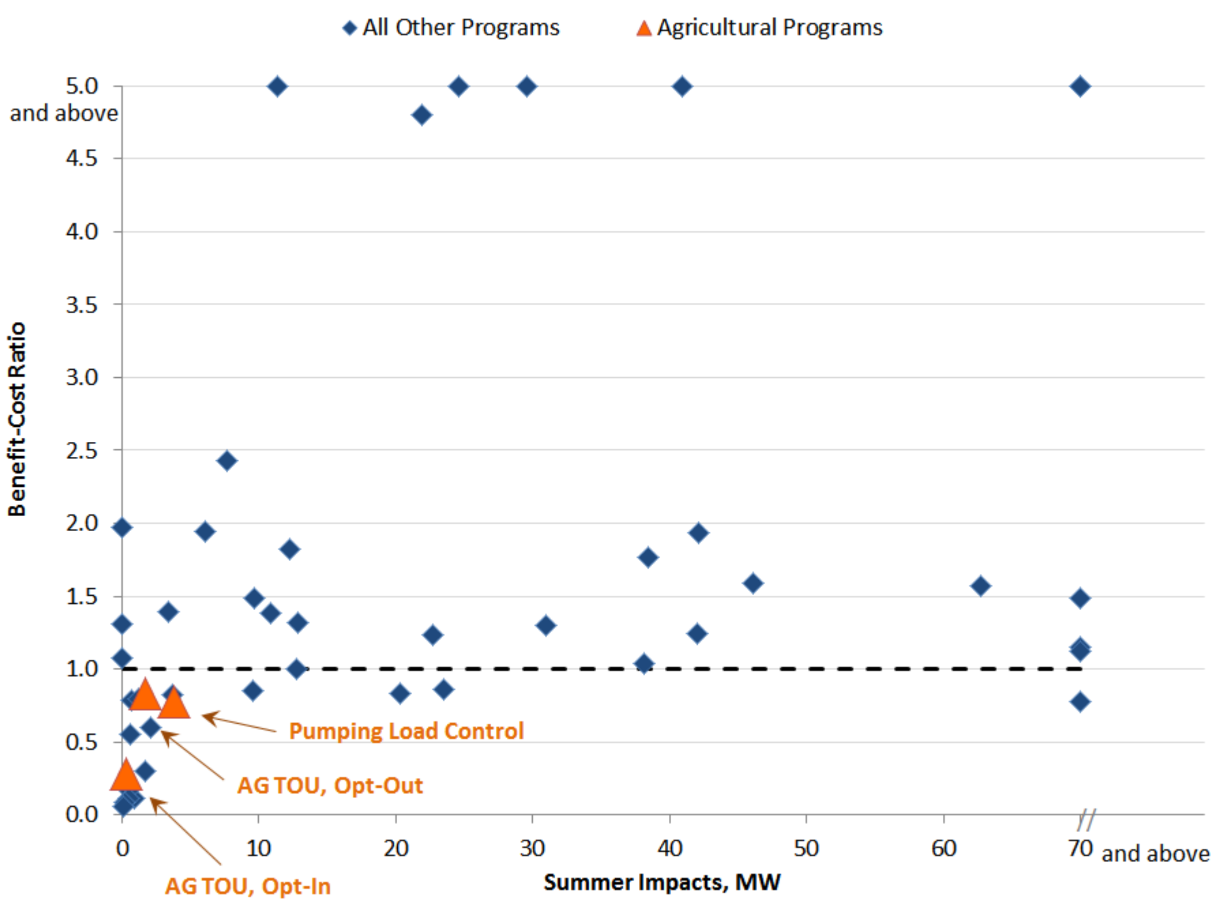
- There is significant untapped potential in a curtailable tariff and a third-party DLC program
- CPP provides similarly large peak impacts
- These programs could be considered the “low hanging fruit” of the available DR options; PGE’s initial program offerings to these customers are an indication that this value is recognized
- Impacts from PGE’s existing programs are currently below potential because it will take time for customers to become educated about the benefits of demand response, due to relatively little DR experience in the region

Finding #8:

Agricultural DR programs are small and uneconomic

Agricultural DR programs are small and uneconomic

Summer Potential vs. B-C Ratio, All Measures



Comments

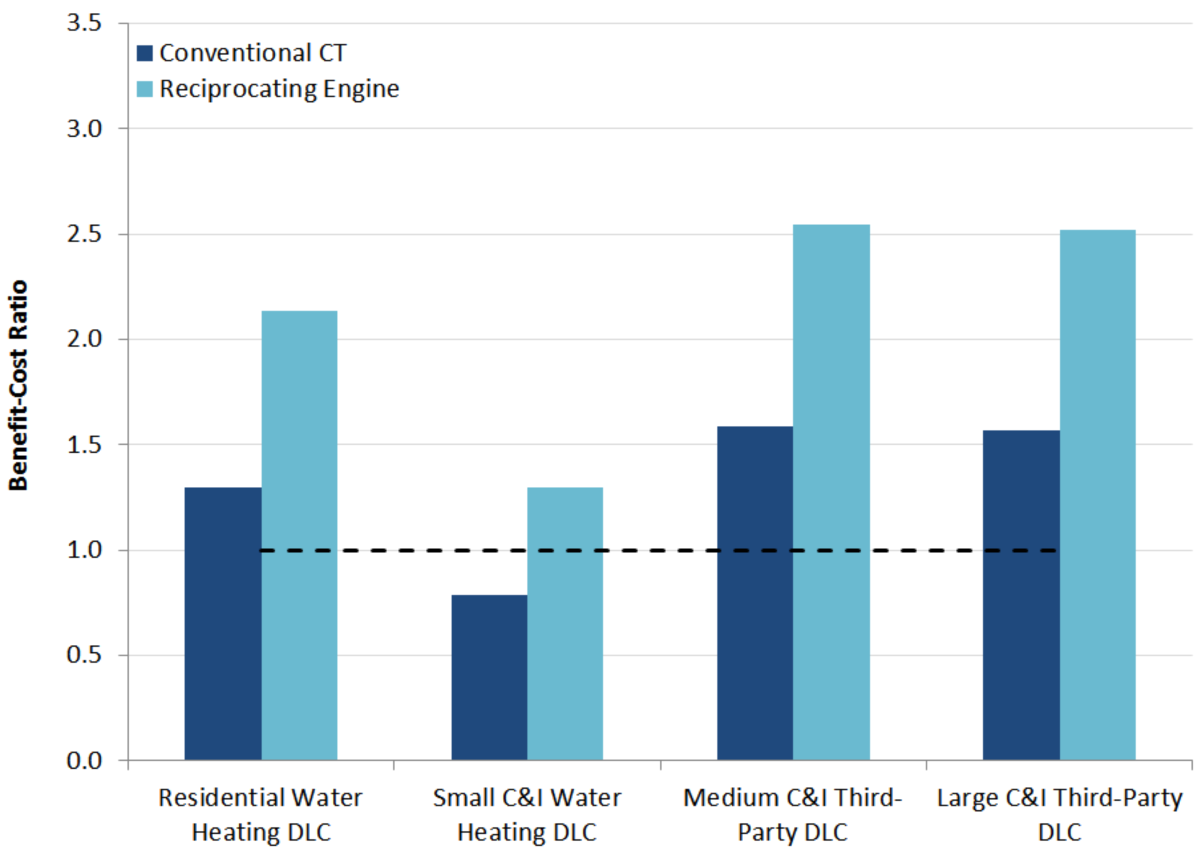
- PGE has little irrigation pumping load, making it an unattractive target for DR programs
- Relative to other options, programs focused on agricultural customers are small and not cost-effective
- Note that pumping load control could become slightly cost-effective if PGE were to become a more heavily summer peaking utility (but is still too small to be considered a top priority)

Finding #9:

The economics of some programs improve when accounting for their ability to provide ancillary services

“Fast” DR provides additional value

Cost-effectiveness for measures with “fast” load decrease <u>and</u> increase capability



Comments

- Mass market water heating load control and medium and large C&I load control could provide fast ramping capability in the form of load increases and decreases
- With a reciprocating engine as the basis for avoided costs, economics improve for all programs and small C&I water heating DLC becomes cost-effective
- It should be noted that this cost-effectiveness analysis is based on the full coincident peak reduction capability of the programs; in practice, they may not be able to provide a reduction of that magnitude at regular intervals as an ancillary service, and the economics could change accordingly

Key Considerations for the Future

Considerations

Run a dynamic pricing / behavioral DR pilot

- A new pilot could provide insight about relatively untested issues such as the impact of a PTR in PGE's service territory, persistence in behavioral DR impacts, and the relative difference in seasonal impacts of these programs (an under-researched issue in general)
- A pilot could also be designed to test a "prices-to-devices" concept involving real-time prices and automated response from specific end-uses, to address fluctuations in supply from renewable generation

Develop a water heating load control program

- There is a clear economic case for water heating load control and the potential benefits are diverse
- Piloting is needed to identify the optimal load control strategies and to further test the technical feasibility

Considerations (continued)

Continue to pursue opportunities in the large and medium C&I sectors

- The large C&I potential can be achieved through curtailable tariffs, third-party programs, and pricing options; which of these to pursue is largely a strategic question, as each have their advantages and disadvantages

Establish well-defined cost-effectiveness protocols

- There does not appear to be a well-established approach to analyzing the cost-effectiveness of DR programs in Oregon
- For example, the appropriate treatment of incentives as costs and the methodology for establishing derate factors to account for operational limitations of DR programs are two areas in need of further discussion

Considerations (continued)

Develop a long-term rates strategy enabled by PGE's AMI investment

- The strategy should address important considerations such as whether to offer new rates on an opt-in versus opt-out basis, the advantages and disadvantages of CPP versus PTR, whether a demand charge or increased customer charge is needed to address inequities in cost recovery, how to transition customers to the new rate options, etc.

Explore the distribution system value of DR

- Recent initiatives have highlighted that the distribution-level value of DR may be understated in current practices
- Additional analysis of distribution system constraints and the potential to deploy DR locally to address these constraints would be a useful research activity

Considerations (continued)

Develop a “supply curve” approach to integrating DR into the IRP modeling process

- DR options can be represented in resource planning models essentially as the equivalent of supply-side resources and dispatched against new generation options to determine the economically optimal amount of DR to add in the future; this can be an informative exercise in understanding how the economics of DR compare to other resources

Presenter information

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Mr. Hledik specializes in the economics of policies and technologies that are focused on the energy consumer. He assists clients confronting complex issues related to the recent slowdown in electricity sales growth and the evolution of utility customers from passive consumers to active managers of their energy needs.

Mr. Hledik has supported utilities, policymakers, law firms, technology firms, research organizations, and wholesale market operators in matters related to retail rate design, energy efficiency, demand response, distributed generation, and smart grid investments. He has worked with more than 50 clients across 30 states and seven countries.

A frequent presenter on the benefits of smarter energy management, Mr. Hledik has spoken at events throughout the United States, as well as in Brazil, Canada, Korea, Saudi Arabia, and Vietnam. He regularly publishes articles on complex retail electricity issues.

Mr. Hledik received his M.S. in Management Science and Engineering from Stanford University, with a concentration in Energy Economics and Policy. He received his B.S. in Applied Science from the University of Pennsylvania, with minors in Economics and Mathematics. Prior to joining The Brattle Group, Mr. Hledik was a research assistant with Stanford University's Energy Modeling Forum and a research analyst at Charles River Associates.

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Load Forecast

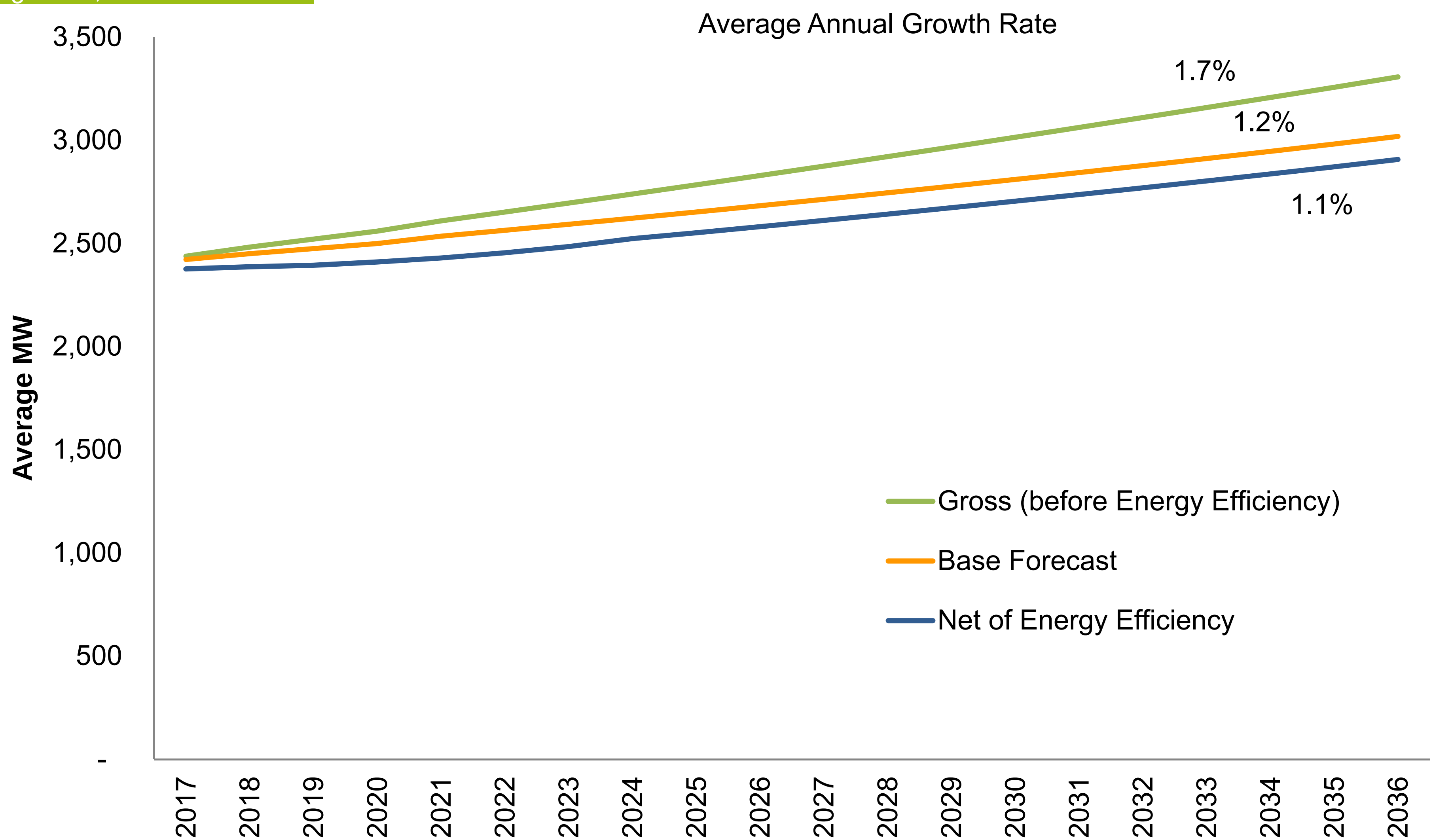
Technical Workshop – Highlights

- Topics
  - Overview of Modeling Initiatives
  - Long Term Energy Models
  - Peak Demand Model
  - Treatment of Programmatic Energy Efficiency

- Q&A Discussion Items
  - Impacts of Climate Change
    - Flexible models allow for scenario analysis
  - Impact of growing summer peaks on system planning
  - Treatment of Programmatic Energy Efficiency
    - How do others in the NW model energy efficiency ?

* Presentation materials are available on IRP site

Forecast Before and After Energy Efficiency



Source: PGE June 2015 Load Forecast.

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Load Forecast Action Item (LC 56)

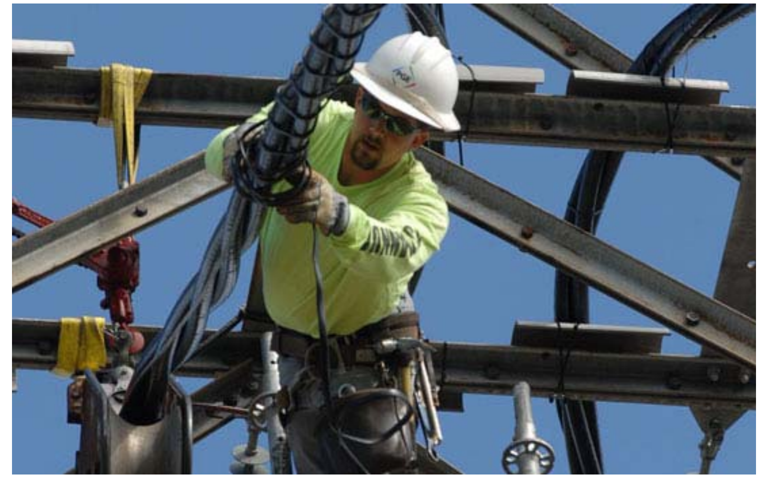
- Order No. 14-415: "…require PGE to convene a series of workshops with interested parties to examine PGE's load forecast methodology in detail."

  - **Public Meeting #1** **(4/2/2015)**
    - PGE load forecasters presented the underlying fundamentals of PGE load growth including sector level model drivers, input assumptions and preliminary forecast output.
    - Third party industry expert (Itron) presented findings from review of PGE's forecast method and models including a detailed discussion of fundamental drivers and methodological approach.
    - PGE held additional meeting for discussion between OPUC Staff, third party reviewer and internal subject matter experts for additional technical review and Q&A following public meeting presentations.

  - **Technical Workshop #1** **(7/15/2015)**
    - PGE hosted a technical workshop focusing solely on presenting load forecasting methodology and allowing a forum for stakeholder participation and feedback. This workshop was well attended, with 14 non-PGE attendees.
    - Subject areas covered included PGE energy forecast method and long term regression models, peak demand forecast and treatment of energy efficiency.

  - **Public Meeting #2** **(7/16/2015)**
    - PGE's most recent load forecast, which will be used for scenario analysis, was presented to stakeholders.

  - **Public Meeting #3** **(8/13/2015)**
    - PGE to present a summary of discussion items from Technical Workshop #1 and review drivers of high and low load scenarios to be included in IRP portfolio analysis.



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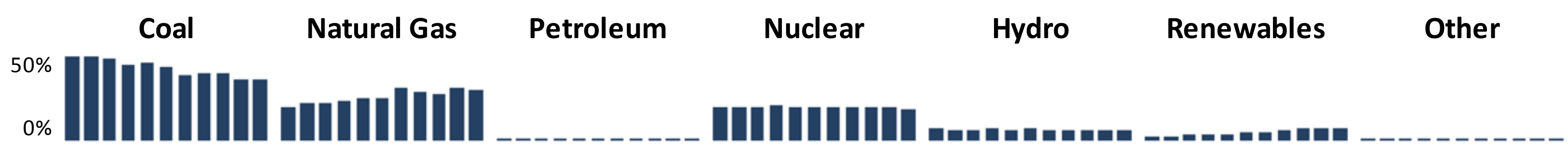
Natural Gas Forecast

Summary

August 13, 2015 Slide 145

- Historically, natural gas has been one of North America's most volatile commodities

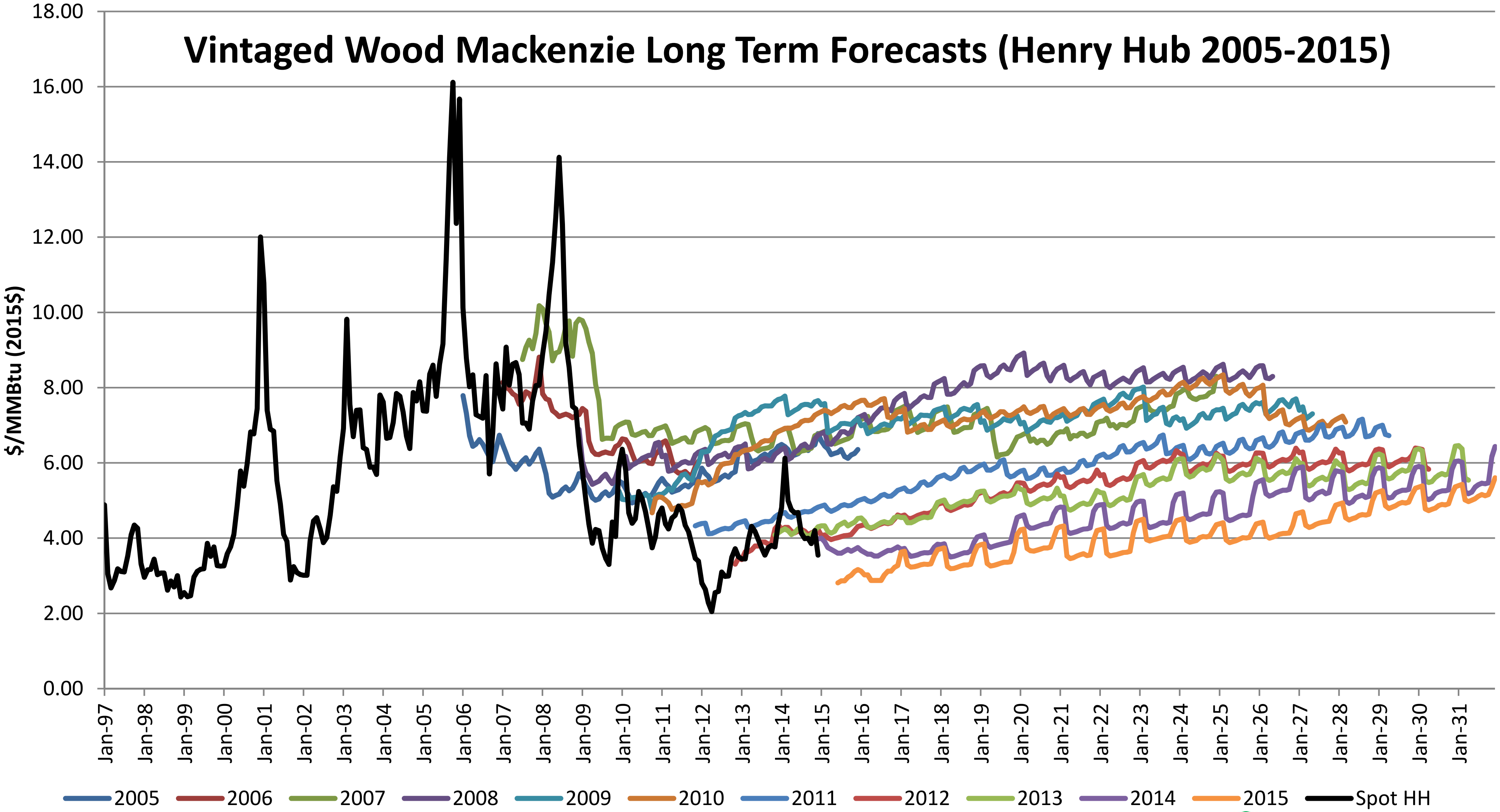
- Shale revolution dramatically increased recoverable supply, lowered prices and diminished expected volatility
- Improvements in extraction process have continued to lower prices
- Electricity generation fueled by natural gas has increased from 20% of total US generation in 2006 to 31% in 2015



- Robust conversation on the environmental impact of hydraulic fracturing continues
  - Hydraulic fracturing banned in New York June 2015
  - Evidence of methane leakage prompted EPA regulation

Historical Forecasts

August 13, 2015 Slide 146



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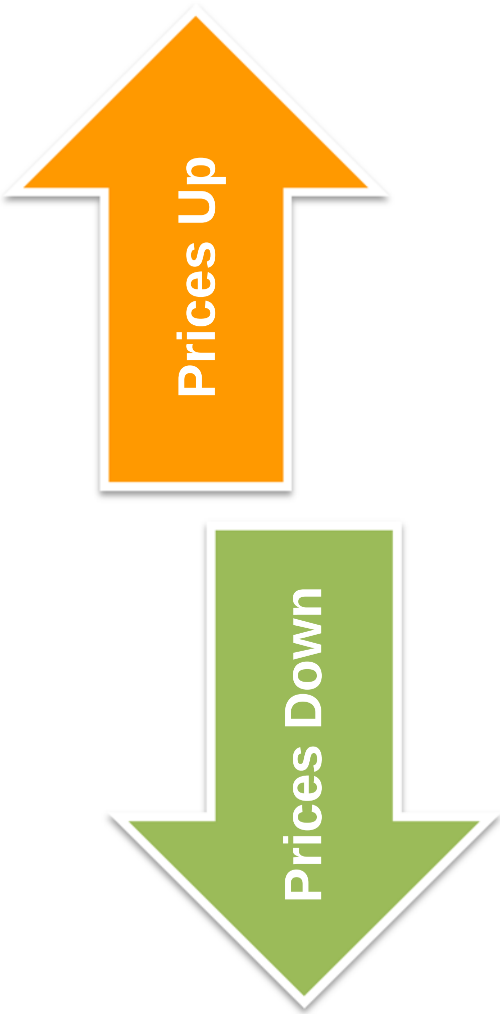
Supply and Demand Updates



- LNG Exports
- Electricity Generation Demand – Carbon Regulation
- Drilling and Recovery Regulation
- Low Oil Prices – Domestic Supply Contraction
- Methanol and Fertilizer Manufacturing
- Mexican Exports

- Expanded Supply
- Increased Extraction Efficiency
- Low Oil Prices – US LNG Demand Down

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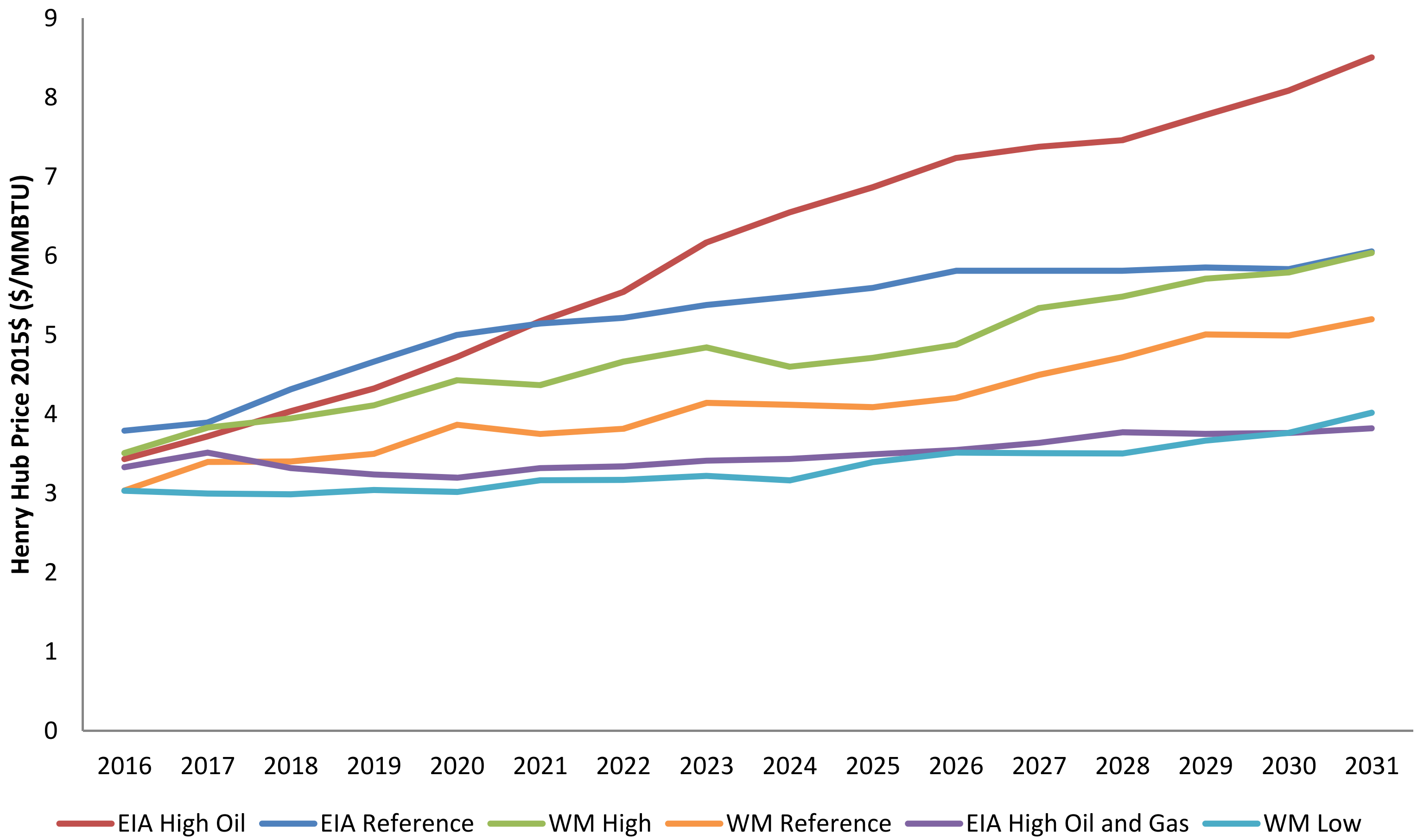
Gas Forecast Sensitivities



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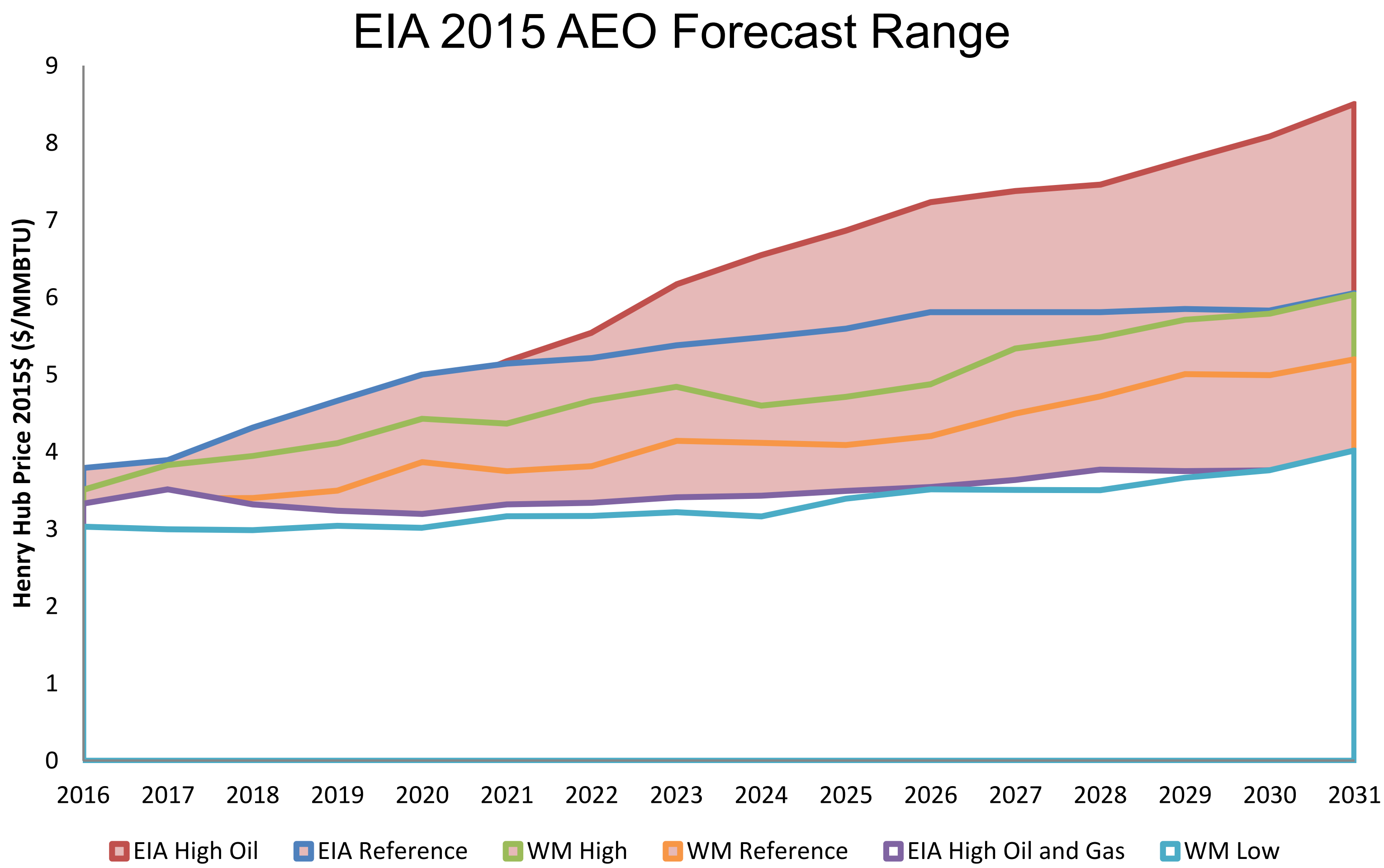
Gas Forecast Sensitivities



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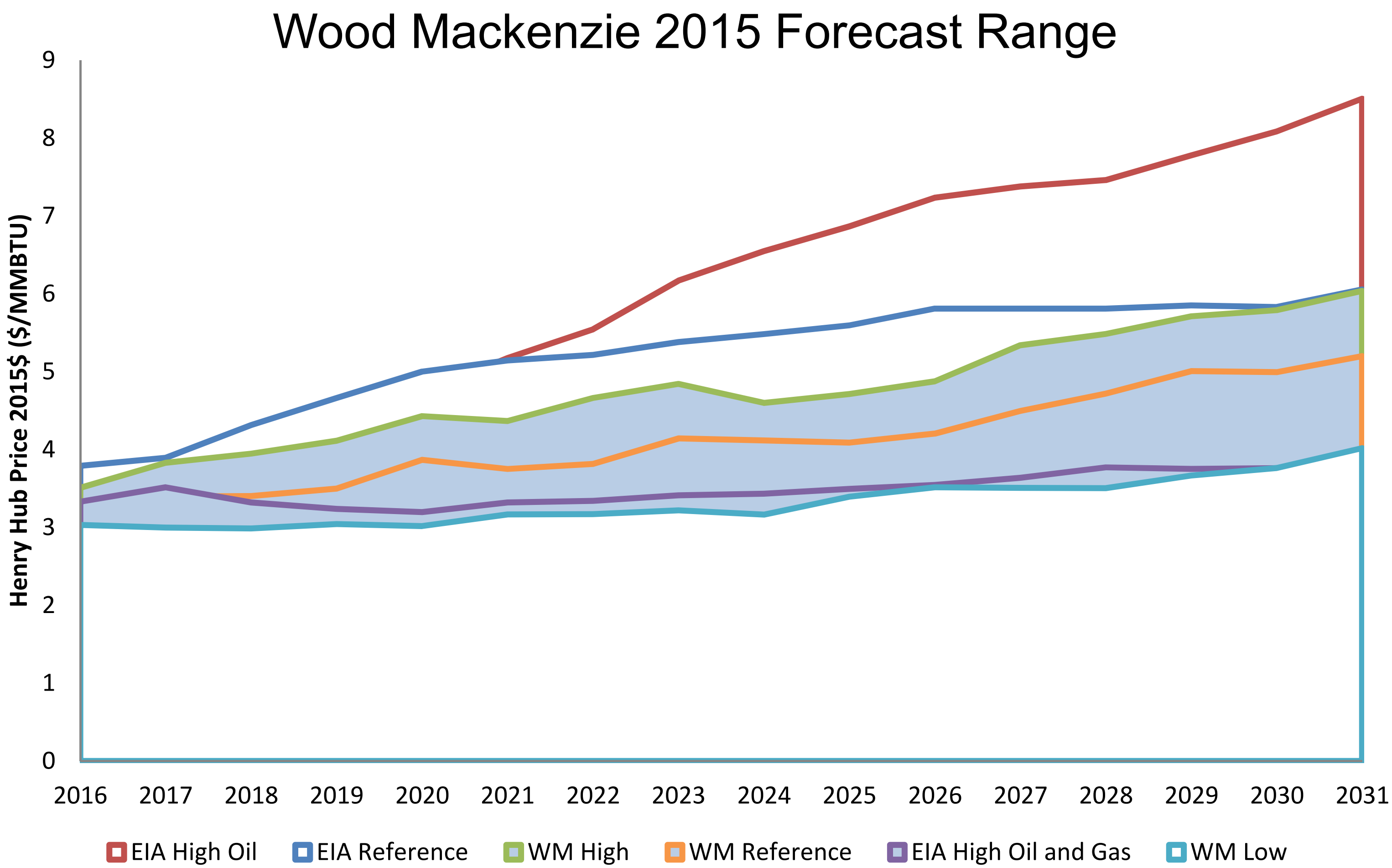
Gas Forecast Sensitivities

August 13, 2015 Slide 155



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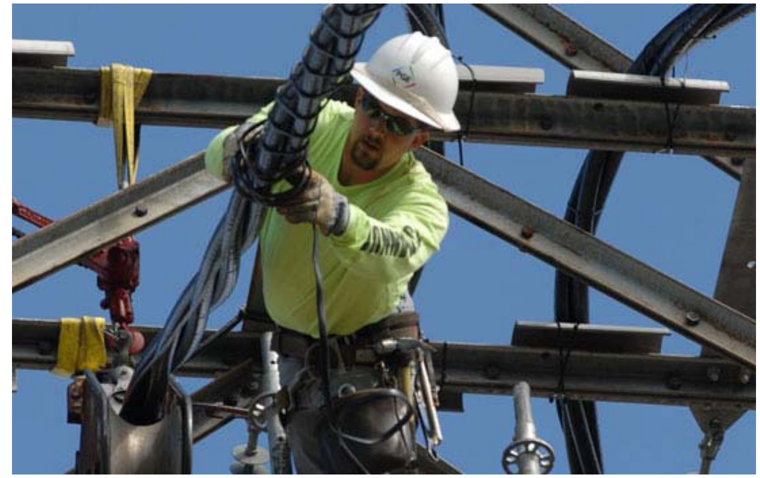
Summary and Recap

- Natural gas growth in US power sector anticipated following Clean Power Plan.
- LNG exports anticipated to increase US gas demand by over 25%.
- Dramatic expansion in supply and continued lowering of breakeven price keeps prices low despite increased demand.
- Pipeline infrastructure limitation keep NW natural gas prices lower than Henry Hub, especially at AECO.



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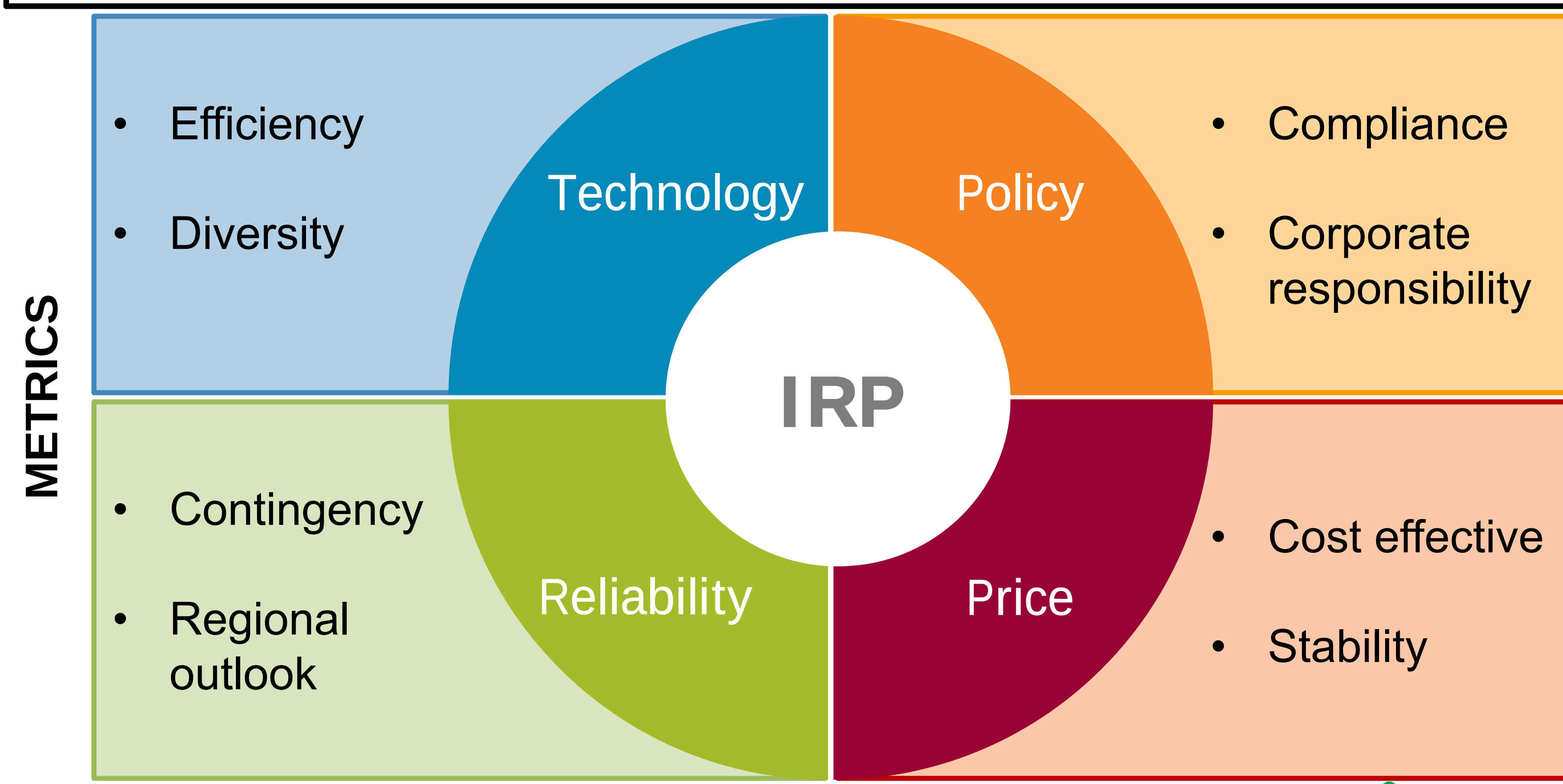
Portfolios and Futures

Portfolios and Futures: Objective

Balance cost and risk to provide opportunity to obtain the best resource portfolio in a constantly changing environment



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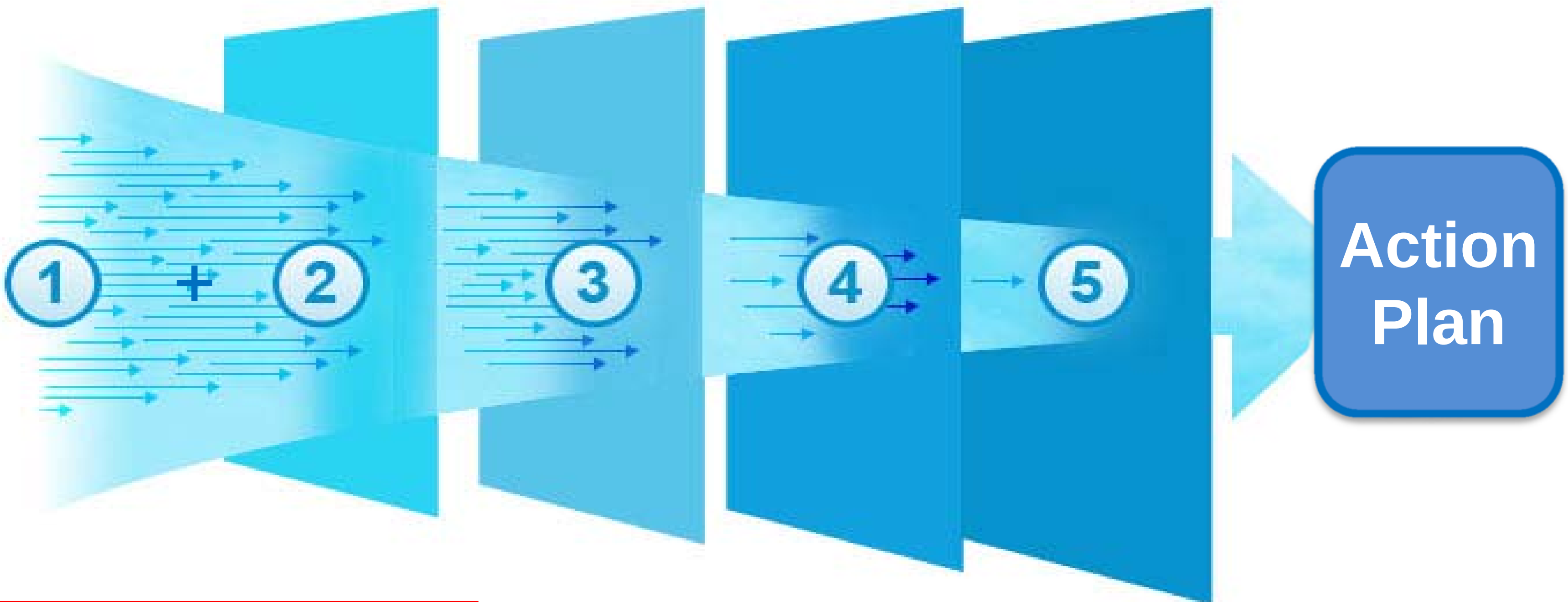
Portfolios and Futures: IRP analytical process



1. Futures

Potential uncertainties affecting the resource plan

2. Portfolios

The broad world of resource alternatives

3. Modeling

AURORAxmp production cost simulation model

4. Scoring

Assess objectives (cost and risk); quantitative and qualitative

5. Results

Selection of the preferred portfolio

Portfolios and Futures: IRP Guidelines

Reference	Select IRP Requirements – Futures
07-002 (1b)	Load requirements
(1b, 4g)	Fuel prices
(1b)	Hydroelectric generation
(1b)	Electricity prices
(1b)	Forced outage rates
(1b, 4g)	Cost of compliance with GHG regulation
(4b)	High and low load growth scenarios (and stochastic load risk)
08-339 (8a)	Base-case scenario reflecting most likely regulation (CO_2, NO_x, SO_x, Hg)
(8a)	CO_2 compliance scenarios from current level to credible “upper reaches”
(8b)	Range of possible NO_x, SO_x, and Hg regulatory futures, if material
(8c)	Trigger point analysis resulting in “substantially different” preferred portfolio

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Portfolios and Futures: Potential risk factors

Policy

Carbon
- 111(d)
- CO_2

Renewable
- RPS
- Tax Credits

Technology

Resources
- EE/DR
- Wind/Solar
- Hydro
- Gas
- Distributed

Capital
- Wind/Solar
- Gas
- Distributed

Reliability

Load
- Forecast
- ESS

Reserves*
- PRM

Price

Power
- Market

Fuel**
- Wind/Solar
- Hydro
- Gas
- Coal

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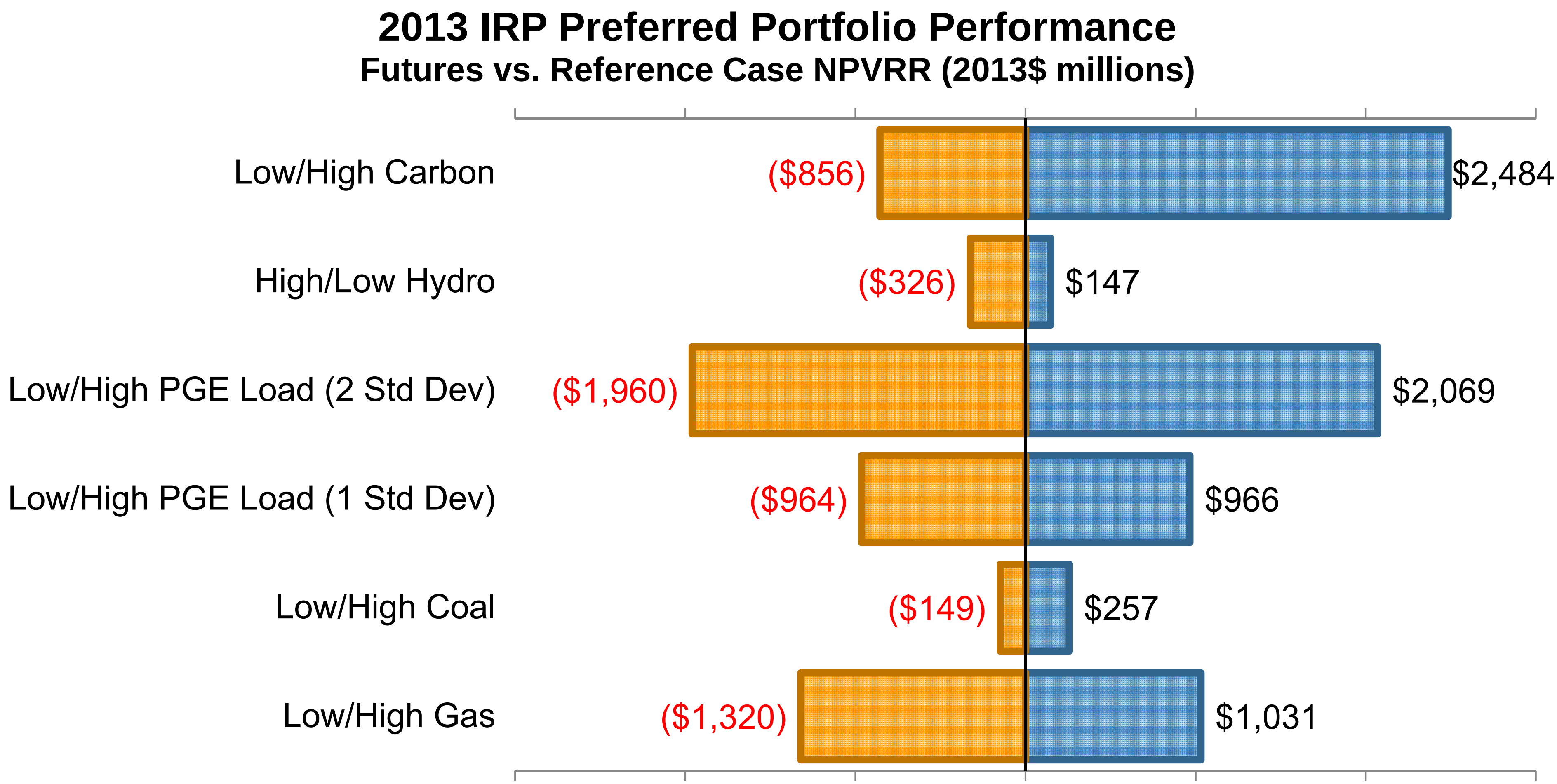
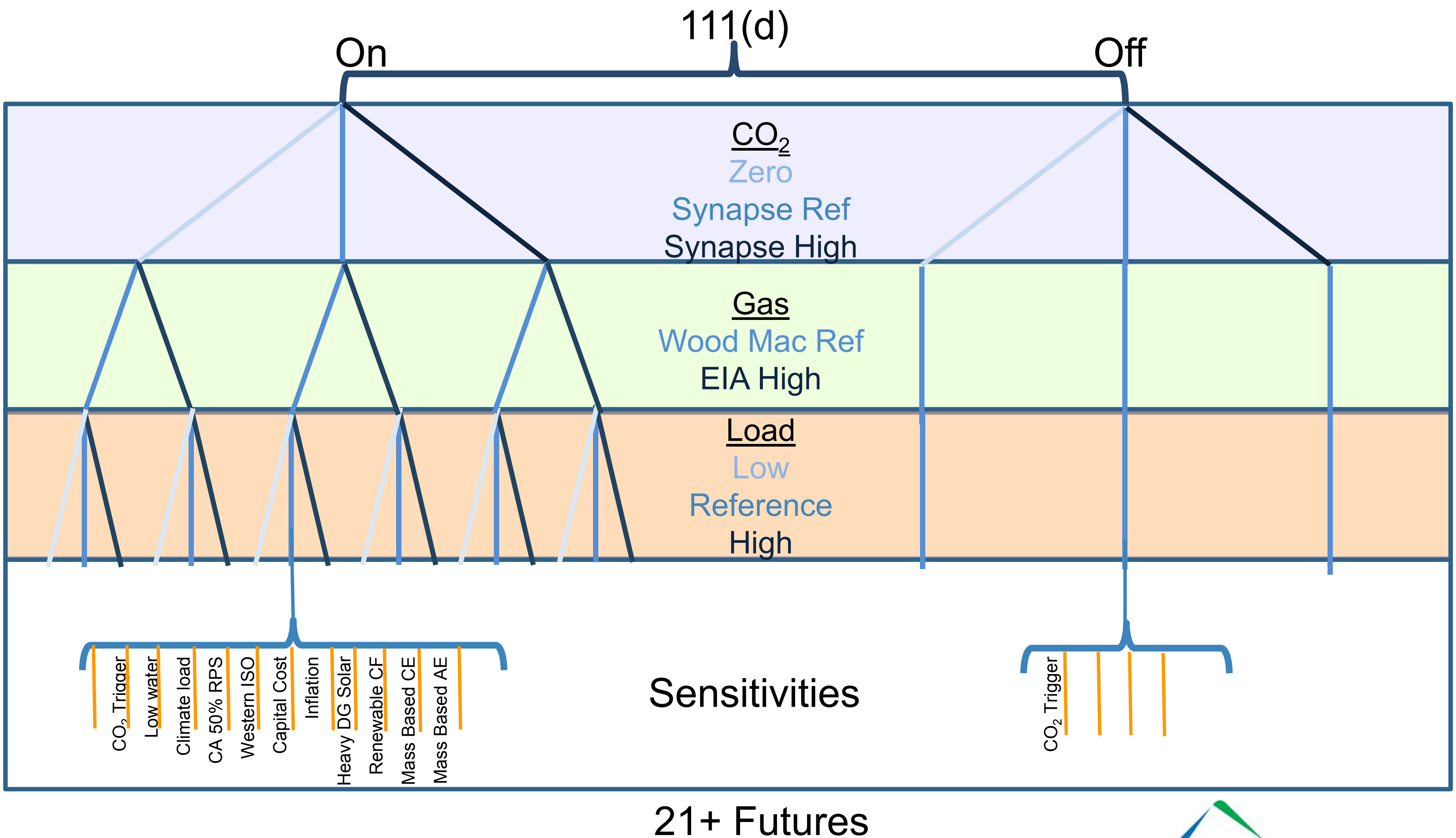
Portfolios and Futures: 2013 IRP impacts

August 13, 2015 Slide 162



Portfolios and Futures: Potential Futures



Portfolios and Futures: Futures feedback

- Use the feedback form on the PGE IRP website
- www.PortlandGeneral.com/IRP

Portfolios and Futures: IRP Guidelines

Reference	Select IRP Requirements – Resource Alternatives
07-002 (1a)	All known resources for meeting the utility's load
(1a, 4h)	Resource fuel types, technologies, lead times, in-service dates, durations and locations
(4c)	Existing and future transmission associated with resource portfolios tested
(5)	Costs for incremental fuel transportation and electric transmission
(5)	Fuel transportation and electric transmission facilities as resource options
(6c)	Determine amount of conservation resources w/o regard to funding limits; Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition
(7)	Evaluate demand response resources

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Portfolios and Futures: Resource alternatives

Central

- Hydro
- Wind
- Solar
- Geothermal
- Biomass
- Gas

Distributed

- Solar
- CHP
- DSG

Demand

- Energy Efficiency
- Demand Response
- CVR

Integration

- Storage
- Smart Grid

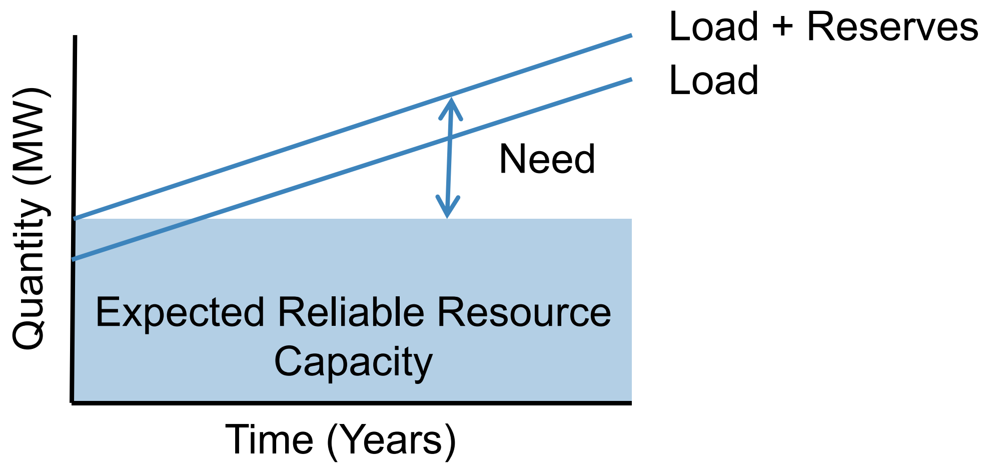
Other

- Market Position
- Existing Resource

Portfolios and Futures: Portfolio design

August 13, 2015 Slide 167

- Preliminary portfolio design to target capacity need
- Capacity need defined by load, contingency reserves (spin/non-spin), planning reserves, and reliable resource capacity



- Studying:
  - planning reserve margin
  - Variable resource contribution to capacity for existing and incremental resources
- Need varies across year
  - portfolios to target summer and winter need

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Portfolios and Futures: Portfolio examples

- Given resource alternatives from Slide 40 and seasonal targets = many possible combinations
- Two examples to meet approximately 800 MW winter need:

Resource	Capacity		
	Nominal MW	Reliable %	Reliable MW
Need			800
Market	200	100	200
CCCT-H	400	100	400
SCCT-F	220	100	220
Total	820		820

Resource	Capacity		
	Nominal MW	Reliable %	Reliable MW
Need			800
Market	200	100	200
Wind	400	5	20
Recip	110	100	110
SCCT-F	440	100	440
Total	1,150		770

- Portfolios will be evaluated across Futures to assess costs and risks

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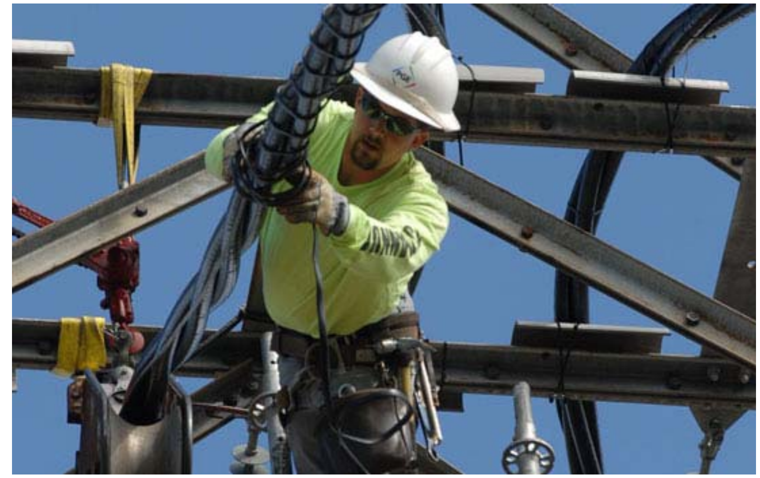

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Appendix

2016 IRP: Feedback Status

Topic	Feedback Received	Resolution	Completed
General	Passing the mic was cumbersome.	For stakeholder questions, provide a stationary microphone at a podium or mics at each table.	4/13/2015
Process	Why is schedule different on handout?	Update schedule slides to account for automation. Plan to revise and post updated slide deck to website and include summary update in ‘thank you’ email.	4/9/2015
Process	Is schedule firm or can the November 18th date be adjusted? (Power Council has important meeting on November 18)	Moved IRP meeting to November 20th.	4/9/2015
Process	Can the October 23rd date be adjusted? (CUB has important meeting on October 23)	Moved IRP meeting to October 21st.	4/9/2015
Environmental Policy	Why will climate data set be a scenario instead of a base case?	PGE to consider suggestion after vetting data.	
Environmental Policy	Does PGE place any type of weather weighting on load forecast?	PGE uses 15-year average weather, with rolling updates	7/15/2015

2016 IRP: Feedback Status

August 13, 2015 Slide 171

Topic	Feedback Received	Resolution	Completed
Load Forecast Methodology	For future discussion, how is the ETO forecast in later years developed?	PGE to addressed questions about EE during 7/15/2015 load forecast technical workshop and 7/16/2015 public meeting.	7/15/2015 and 7/16/2015
Load Forecast Methodology	Comment on in-fill vs. suburban sprawl – suggestion to be cautious about moving to more standard household variables	PGE to take note.	4/8/2015
Load Forecast Methodology	Request to show load growth with and without EE.	PGE shared chart showing load growth with and without in Public Meeting #3 presentation.	8/13/2015
Load Forecast Methodology	What % of PGE service territory is within the urban growth boundary?	90% of the UGB is within PGE Service Territory UGB is 822.7 sq. mi. PGE SVC Territory is 7532.2 sq. mi. Overlap is 741.6 sq. mi.	4/8/2015
Environmental Policy	Will temperature data drive (1) increased cooling demand and (2) an acceleration of cooling device purchases?	PGE to follow-up internally with load forecast staff.	Est. 8/13/2015 (with scenarios and climate change weather discussion)

2016 IRP: Feedback Status

Topic	Feedback Received	Resolution	Completed
DG Study	What is the data source for sage grouse?	Sage grouse habitat based on the WECC Geospatial data viewer: http://184.169.179.203/flexviewers/WECC3/index.html	8/13/2015
DG Study	What QF rate was used?	The Long-term Variable Solar QF rate from PGE was used as the QF rate.	8/13/2015
DG Study	Request made to distribute DG reports before Draft IRP issued, if possible	Distributed Solar Study (by CPR) posted to www.portlandgeneral.com/irp	8/13/2015
DG Study	Request made to distribute DG reports before Draft IRP issued, if possible	Solar Generation Market Research (by B&V) being finalized and will be posted when complete.	
Supply Side Assumptions	Wind: What is driving overnight capital?	PGE to provide more detailed answer after further review.	
Supply Side Assumptions	Reciprocating engines: why did net capacity change (98 MW to 110 MW)?	PGE to provide more detailed answer after further review.	

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