Emerging Best Practices for Modeling Energy Storage in Integrated Resource Plans

April 6, 2022

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Northwest Energy Systems Symposium

PNNL is operated by Battelle for the U.S. Department of Energy

Acknowledgment

The work described in this presentation is made possible through funding provided by the U.S. Department of Energy's Office of Electricity, through the Energy Storage Program under the direction of Dr. Imre Gyuk.

I also wish to acknowledge the support of my colleagues and co-authors on these reports, Alan Cooke and Rebecca O'Neil.

Agenda

- Initial Paper: Energy Storage in Integrated Resource Plans
  - Barriers to Storage in IRPs
  - Study Findings
- Current Work: Emerging Best Practices for Modeling Storage in IRPs
  - The IRP Process
  - Northern Indiana Public Service Company
  - Public Service Co. of New Mexico
  - Puget Sound Energy
  - California PUC
  - Portland General Electric
  - Summary: Points of Entry for Storage Modeling and Other Takeaways

Energy Storage in Integrated Resource Plans

Overview – Why Analyze IRPs?

- An integrated resource plan (IRP) is a tool by which utilities identify their future generation needs and select the optimal resource portfolio for meeting them
  - Prepared for review/approval by state regulators
  - Traditionally associated with vertically integrated states, but some market-facing states have started re-introducing them (California, Michigan)

- IRPs provide insight into how utilities are adapting to changing technologies and policies

- For this report, we reviewed 21 utility IRPs from around the country, prepared from 2016-2018

Key IRP Assumptions Create Barriers for Storage

- Preparing an IRP is an incredibly complex exercise
  - Load and generation must be kept in constant balance
  - Dozens of generators, market interfaces, fuel costs, changing load patterns (DG, EVs, etc.)
  - For each interval, solving the load/generation equation requires consideration of many complex variables
  - A 20-year plan looking at hourly intervals must solve for 175,200 data points

- As a result, resource plans make several simplifying planning assumptions
  - Hourly planning resolution
  - Substitution of reserve margins for ancillary services
  - Focus on generation only (no distribution planning, limited transmission planning)

- Energy storage is a flexible and scalable resource; these assumptions cause it to be undervalued
  - Hourly planning resolution: Flexible, intra-hour benefits omitted
  - Reserve margins: Ancillary service benefits omitted
  - Generation focus: Transmission, distribution benefits omitted

Report Summary

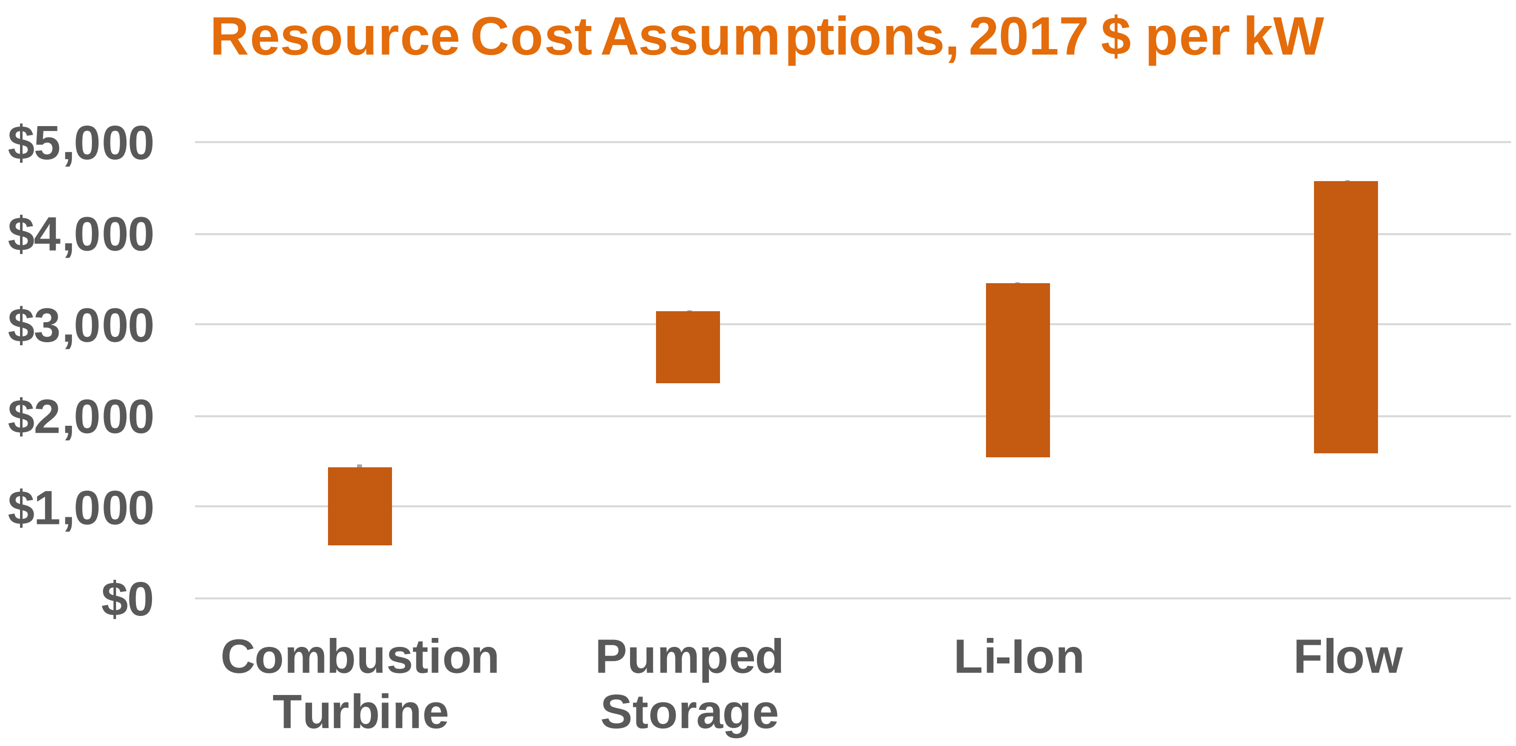
We examined how 21 U.S. utilities are treating energy storage in integrated resource planning.

High-level findings:

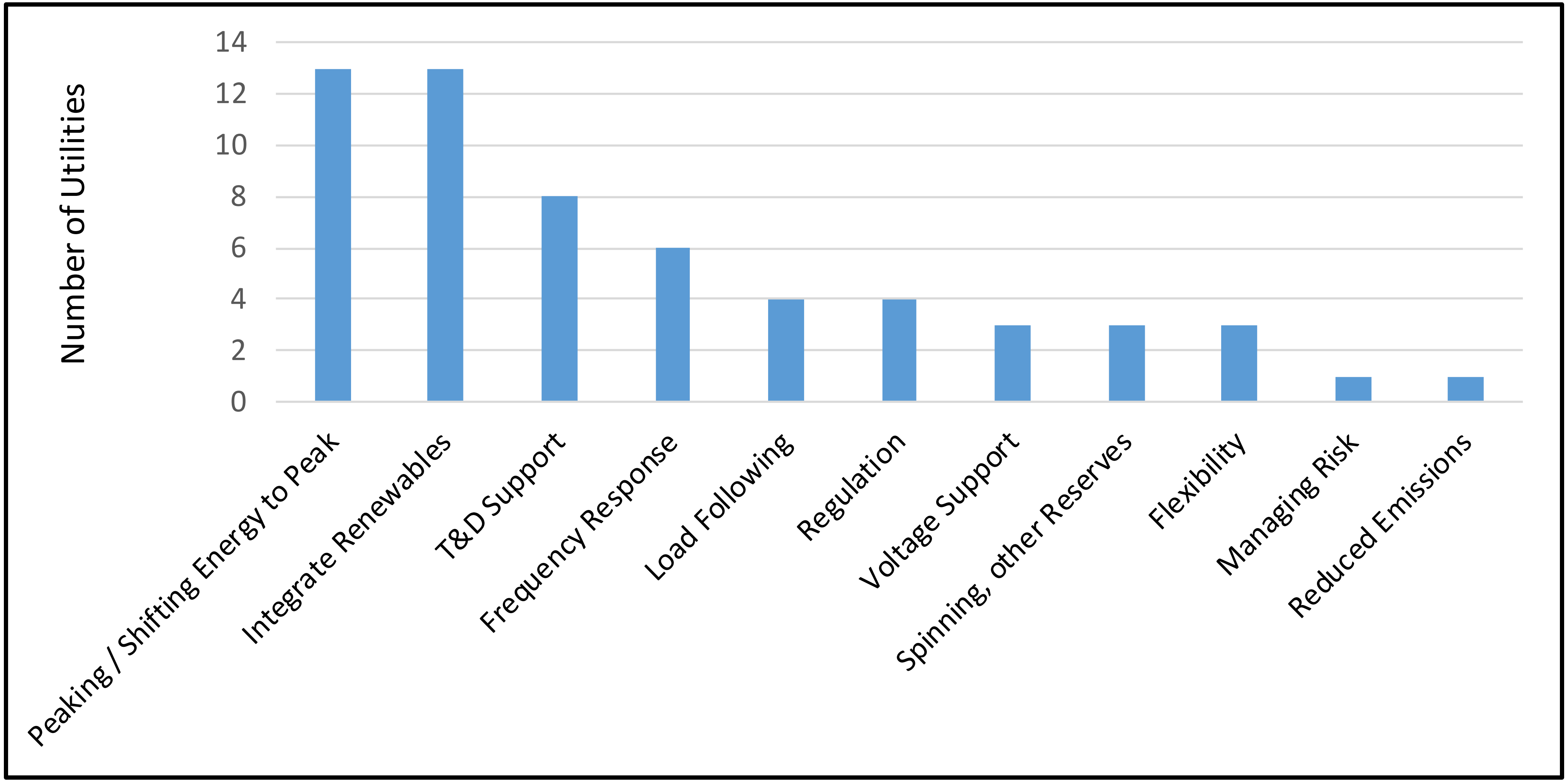
- **15 of the 21 IRPs included battery storage in their process. Of those:**
  - Eight plans did not select battery storage
  - Five plans selected batteries in their preferred portfolio
  - Two plans selected batteries in an alternate portfolio
- **10 of the 21 IRPs included pumped hydro storage in their process. Of those:**
  - Seven plans did not select pumped hydro
  - Two plans selected pumped hydro in the preferred portfolio (both expansions of existing facilities)
  - One plan selected a new pumped hydro project in an alternate portfolio (high emissions prices)

Finding: Utilities Are Relatively Uncertain About Battery Costs

Cost assumptions for technologically mature resources such as combustion turbines and pumped storage tended to cover a smaller range than assumptions for less mature resources, such as lithium-ion and flow batteries:



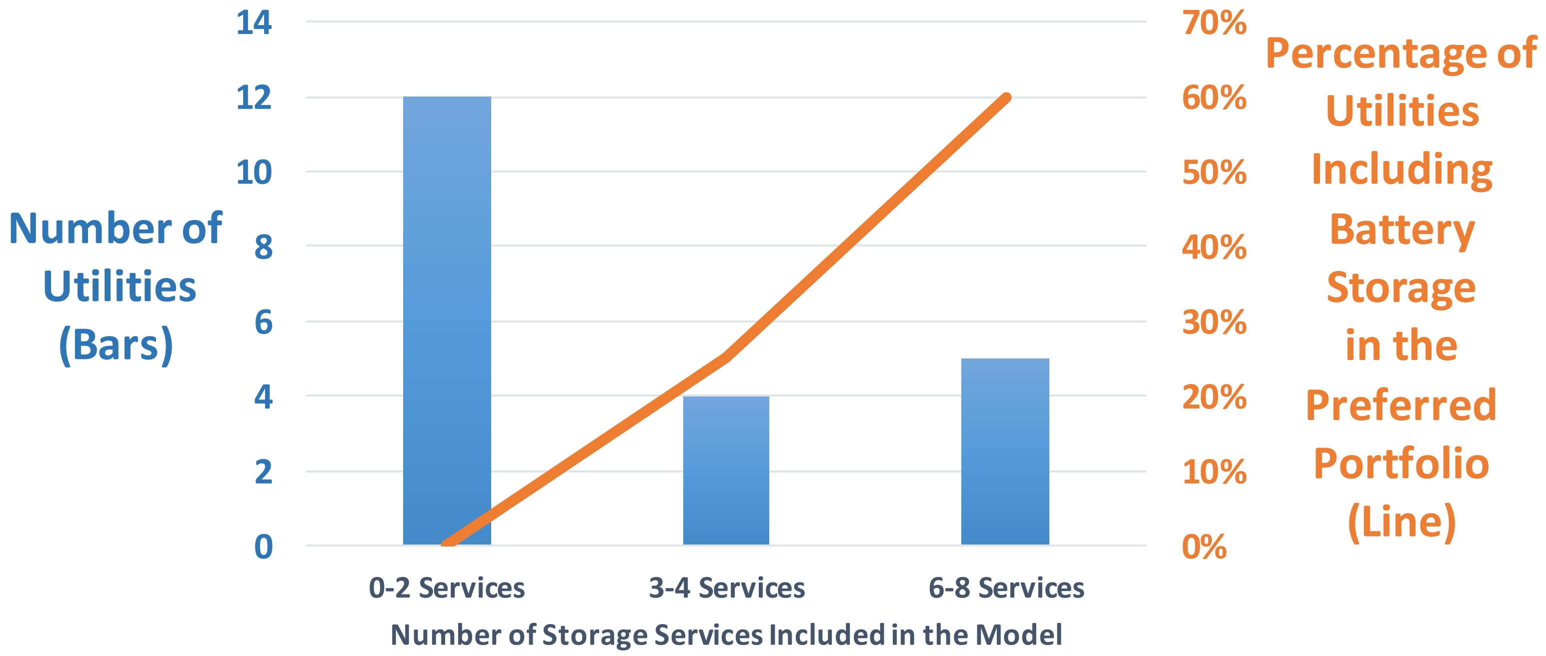
Storage Services Identified in IRPs



Finding: As More Services are Included, Likelihood of Selecting Storage Increases

As utilities account for more services provided by energy storage, the likelihood of storage being selected in the preferred portfolio increases:

Percentage of Utilities Including Battery Storage in the Preferred Portfolio, by Number of Services Modeled

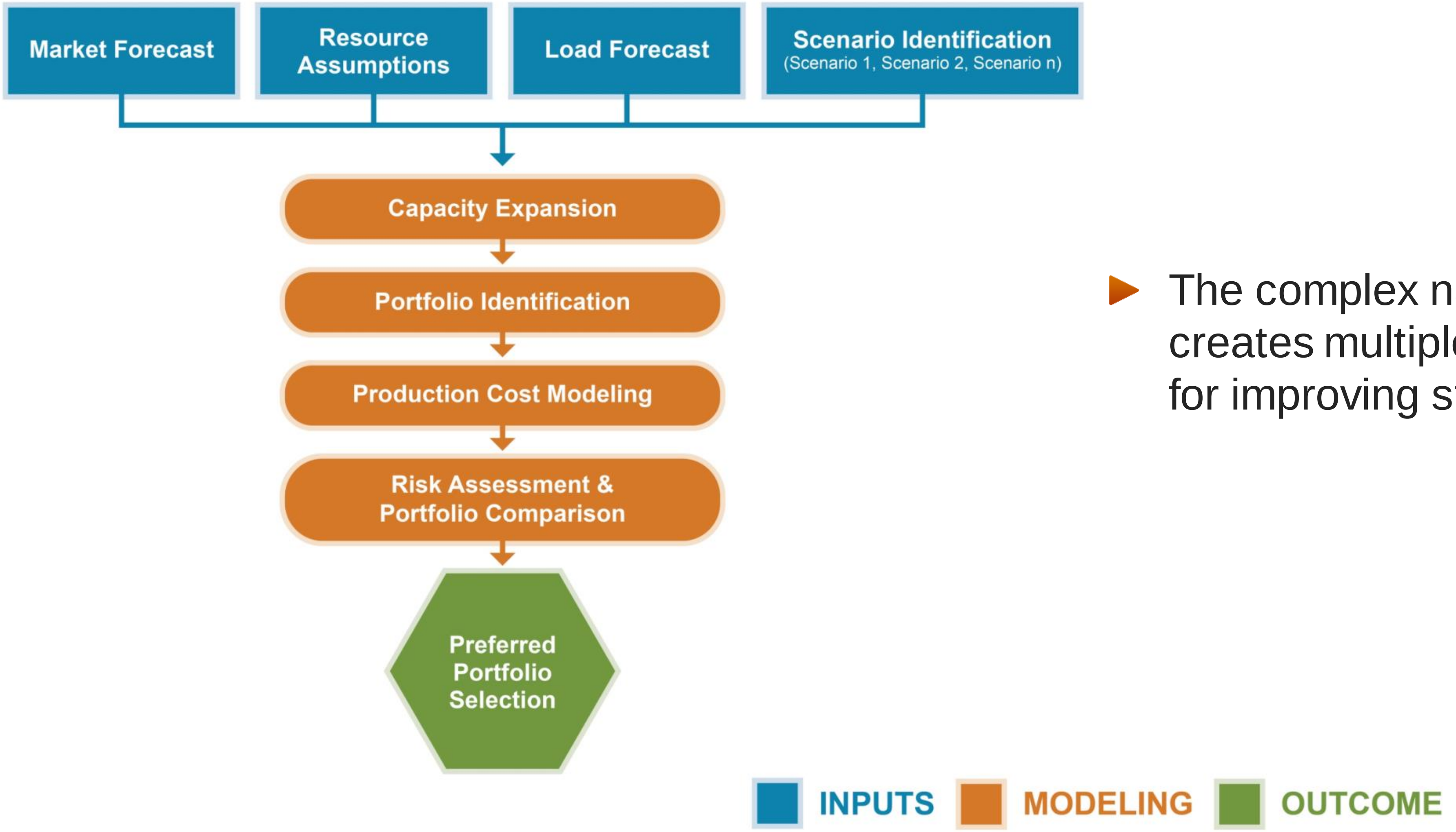


Key Takeaways

- Some IRPs identified multiple services that storage can provide, but it was clear the IRP did not analyze or capture these benefits
- Some of this is due to a lack of tools
  - Several utilities identified a lack of modeling tools capable of analyzing storage as a barrier
  - But some utilities were beginning to procure new tools and develop new processes for improving how they model storage
- Largely, our review noted a full accounting of the costs of storage, but not a full accounting of the benefits

Emerging Planning Models

The IRP Process



- The complex nature of an IRP creates multiple points of entry for improving storage modeling

Project Objectives

Inform utilities, regulators, and other stakeholders interested in improving the representation of energy storage in IRP models by:

- Identifying the mechanisms that leading utilities are developing to model energy storage;
- Describing how those mechanisms are deployed in the IRP process; and
- Evaluating the relative complexity and impact of those mechanisms.

As used here, complexity is a subjective term based on the cost and disruption associated with deploying each mechanism relative to the other mechanisms.

Northern Indiana Public Service Co. (2018) – More Accurate Cost & Performance Assumptions

After stakeholders criticized the utility's lack of transparency in formulating cost assumptions for its 2016 IRP, NIPSCO changed its practice for the 2018 IRP:

- Conducted an all-source request for proposals at the beginning of the 2018 IRP process
- NIPSCO received 90 bids representing nine resource types (including nine standalone storage bids and 12 storage hybrid bids); the results were used to inform the utility's cost assumptions

Results of NIPSCO's Initial Cost Survey

2017 $/kW	Solar PV – Utility Scale	Solar PV – DG	Onshore Wind	Offshore wind	Li-Ion battery (4-hr)	Biomass	CHP	Microturbines
Average	1,673	2,466	1,719	5,728	2,110	5,475	3,182	5,001
Median	1,453	2,466	1,677	6,454	2,160	6,522	2,213	5,001
Min	1,155	2,400	1,425	3,430	1,317	2,500	1,350	4,943
Max	2,370	2,532	1,977	7,300	3,114	7,300	5,984	5,059

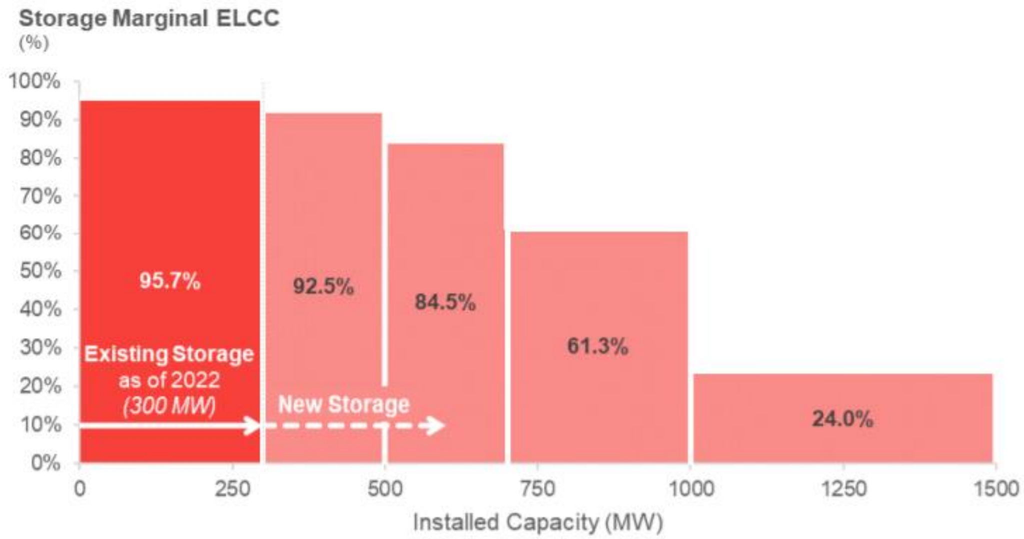
Average bids received in response to the RFP:

- Solar + storage: $1,183 / kW
- Standalone storage: $1,349/ kW

Public Service Co. of New Mexico (2021) – Reserve Margins and Effective Load Carrying Capability

Driven by resource adequacy challenges experienced throughout the West in August 2020 (CAISO as well as PNM's own experience), PNM determined that longstanding assumptions about market depth were no longer viable.

- PNM experienced an outage at a large thermal generator in August, and was unable to procure replacement power in the market
- Growing reliance on renewable generation and an emerging duck curve in the state exacerbate those pressures
- To maintain its loss of load (energy) standard of 0.2 days per year, PNM calculated that it would need to increase its planning reserve margin from 13% to 18%
- To help determine how energy storage could contribute to the increased reserve margin, PNM also calculated how energy storage's effective load carrying capability (ELCC) would decline as its presence grew on the grid:



PNM 2021 IRP, pg. 117

Puget Sound Energy (2017/2021) – Bolt-on Flexibility Analysis

In its 2017 and 2021 IRPs, Puget Sound Energy developed two ways to use an external model to calculate flexibility benefits and incorporate those benefits into the IRP:

2017: Portfolio Re-Optimization

- Re-runs each portfolio through a sub-hourly model (PLEXOS) nine times, adding a different flexible resource each time
- Any reductions in portfolio costs are levelized and attributed to the resource
- The portfolio is then re-run through the capacity expansion model with the new values

Capacity Expansion → Portfolio Identification → Production Cost Modeling → Risk Assessment & Portfolio Comparison

Flexibility Analysis → (between Production Cost Modeling and Risk Assessment & Portfolio Comparison)

Outcome: 75 MW by 2037 became 50 MW by 2023 & 75 MW by 2027

2021: Informed Portfolio Development

- Prior to modeling each scenario, PSE performs the flexibility analysis using its existing portfolio
- Flexibility benefits identified through this process are used in the resource cost assumptions in each portfolio's development

Flexibility Analysis → (before Capacity Expansion)

Capacity Expansion → Portfolio Identification → Production Cost Modeling → Risk Assessment & Portfolio Comparison

Outcome: 450 MW by 2045

California PUC (2020) – Expanded Forecasting and Modeling

California's recently re-instituted IRP process is unique in that state regulators – who normally review and respond to IRPs – lead the development of a unified, statewide reference system plan

- Process utilizes a 10-year horizon and with the objective of meeting a CPUC-established emissions target (subject to legislative guidelines)
- Load-serving utilities are then required to prepare individual plans identifying their obligations under the reference system plan and their plan for achieving them

During the second biennial planning cycle (2019-2020), the CPUC made two modeling enhancements related to storage:

- Allowed storage resources to provide additional services (spin & non-spin reserve) in the loss of load probability model (SERVM) used to test the reliability of different portfolios
- Commissioned a third-party energy storage potential study

California PUC (2020) – Expanded Modeling

Ancillary service markets are much shallower than energy and capacity markets. Allowing storage to provide additional services unlocks additional value and potential

Average hourly values of ancillary services in CAISO, 2020

Hour Ending	Regulation Down	Regulation Up	Spinning Reserve	Non-Spinning Reserve
1	$6.88	$5.22	$1.90	$0.10
2	$5.19	$3.98	$1.47	$0.12
3	$5.93	$3.79	$1.29	$0.11
4	$4.98	$3.65	$1.17	$0.11
5	$5.30	$3.75	$1.33	$0.11
6	$4.96	$4.64	$2.27	$0.12
7	$6.31	$9.15	$5.12	$0.13
8	$10.00	$7.52	$2.94	$0.12
9	$14.18	$6.61	$1.52	$0.14
10	$14.65	$5.94	$1.19	$0.13
11	$16.57	$6.66	$1.12	$0.11
12	$17.61	$7.44	$1.37	$0.11
13	$16.64	$6.65	$1.57	$0.13
14	$17.12	$7.92	$2.03	$0.17
15	$15.85	$8.78	$2.69	$0.51
16	$11.75	$8.93	$3.82	$1.06
17	$10.48	$12.04	$7.50	$2.66
18	$7.91	$22.74	$18.64	$11.09
19	$5.93	$35.06	$31.39	$23.66
20	$5.42	$29.90	$26.37	$16.98
21	$5.64	$13.52	$9.96	$4.10
22	$4.73	$8.74	$5.09	$1.43
23	$6.00	$6.41	$3.07	$0.39
24	$6.70	$5.87	$2.03	$0.12

Hour's most valuable service

Hour's second-most valuable service

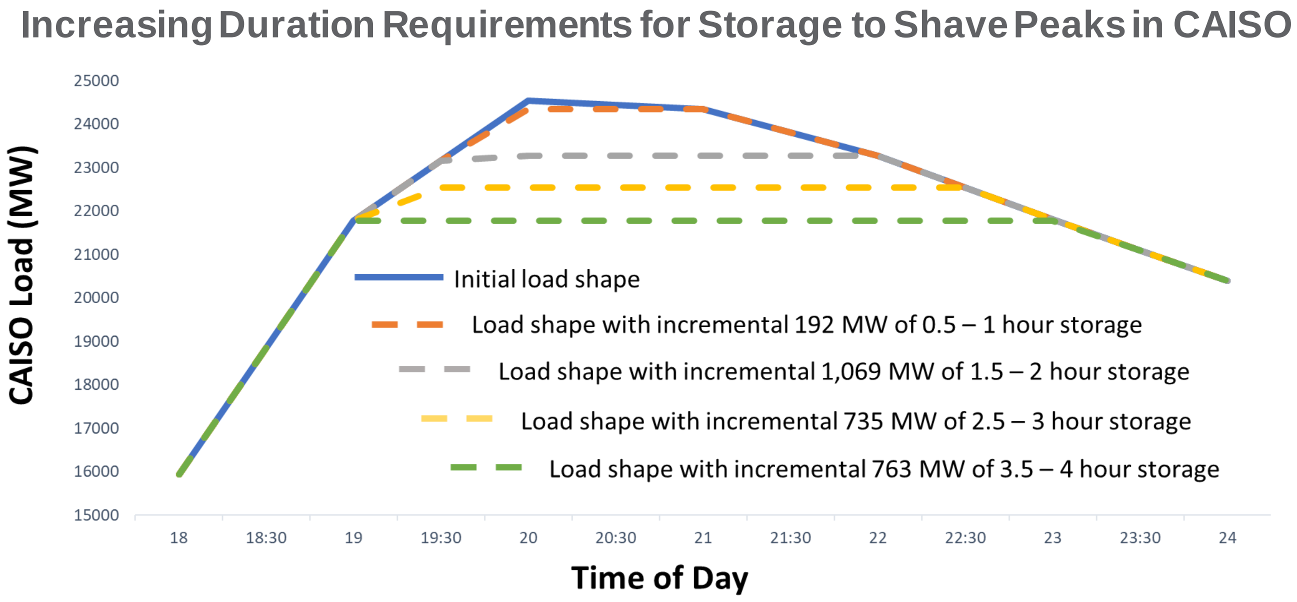
Hour's third-most valuable service

Hour's least valuable service

California PUC (2020) – Expanded Forecasting

As energy storage contributes to peak needs, there are points of inflection at which duration requirements increase for incremental investments

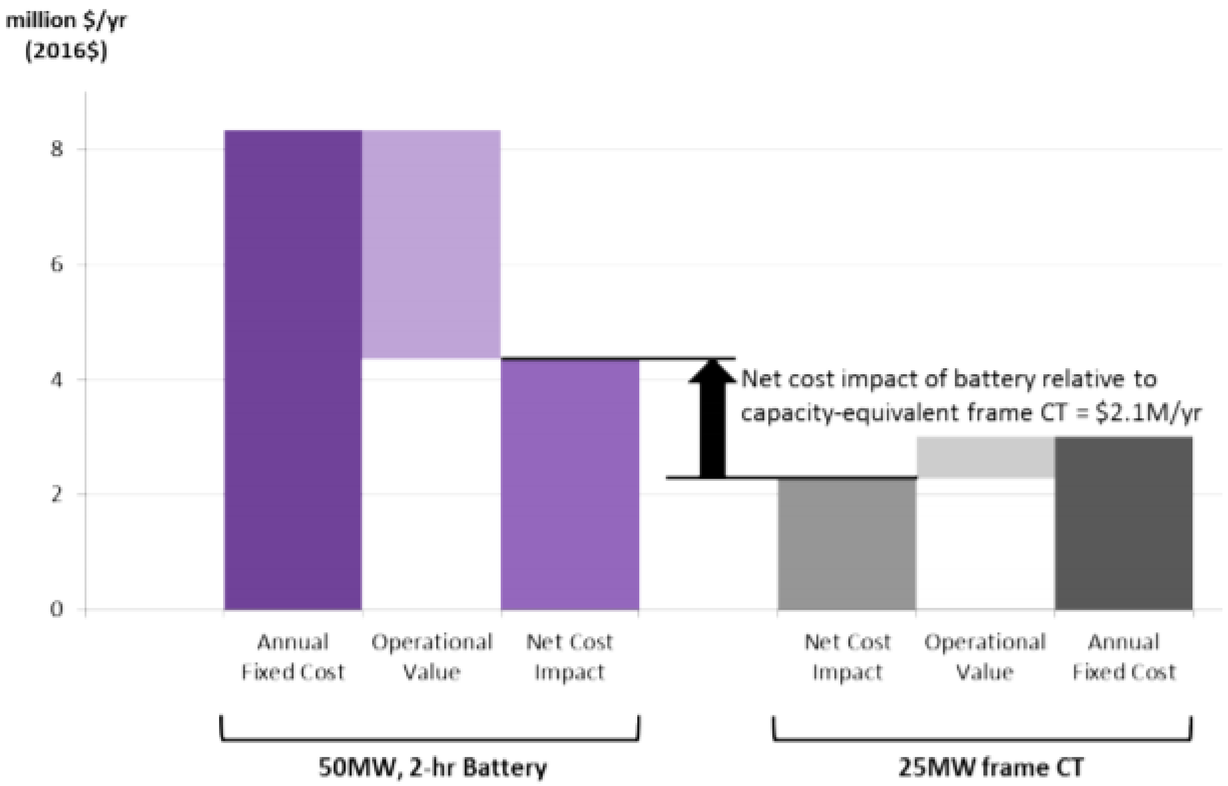
- To quantify these diminishing returns and how much 4-hour storage could be cost-effectively deployed when accounting for them, CAISO commissioned a third-party storage potential study (Astrape Consulting)
- Potential studies are a longstanding practice in the energy efficiency space



- The study concluded that, assuming the continued rapid growth of solar generation, more than 10GW of 4-hour storage could be deployed within CAISO by 2030

Portland General Electric (2016) – Net Cost Model

- Recognizing that its hourly capacity expansion model would not capture the intra-hour benefits of energy storage and other flexible resources, PGE developed the "Net Cost" methodology in its 2016 IRP:
  - Utilizes a PGE-developed, external model to quantify intra-hour benefits of a resource ("operational value")
  - The operational value was credited against the resource's annual fixed cost
  - While storage was not the most cost-effective option under this analysis, the delta between it and other resources was reduced
  - Multiple free modeling tools are available to conduct this type of analysis
    - PNNL: [Energy Storage Evaluation Tool]
    - EPRI: [StorageVET]



Portland General Electric 2016 IRP, p. 239

Portland General Electric (2019) – Valuing Flexibility

For its 2019 IRP, PGE made three changes that impacted its valuation of energy storage:

- Constraining the model from selecting new GHG-emitting resources
- Fully integrating the utility's in-house, intra-hour Resource Optimization Model (ROM) into the capacity expansion process
- Allowing the capacity expansion model to select dispatchable, behind-the-meter storage to meet capacity needs.

Using ROM, PGE modeled its system one week at a time, stepping through three levels of granularity while preserving commitments made in previous levels:

- Day-ahead (hourly unit commitment)
- Hour-ahead (15-minute unit commitment)
- Real-time (15-minute unit commitment)

Through this process, PGE was able to drill down into its real-time ancillary service needs and quantify a flexibility value (levelized value of real-time ancillary service benefits) for different resources.

	Flexibility Value (2020$/kW-yr)
Solar + Storage	-
2-hour Battery	$23.73
4-hour Battery	$28.10
6-hour Battery	$29.43
Pumped Storage	$25.95
CCCT	$8.40
LMS 100	$8.87
Reciprocating Engines	$9.19
SCCT	$4.82

PGE 2019

Pacific Northwest NATIONAL LABORATORY

Portland General Electric (2019) – Valuing Long-Duration and Behind-the-Meter Storage

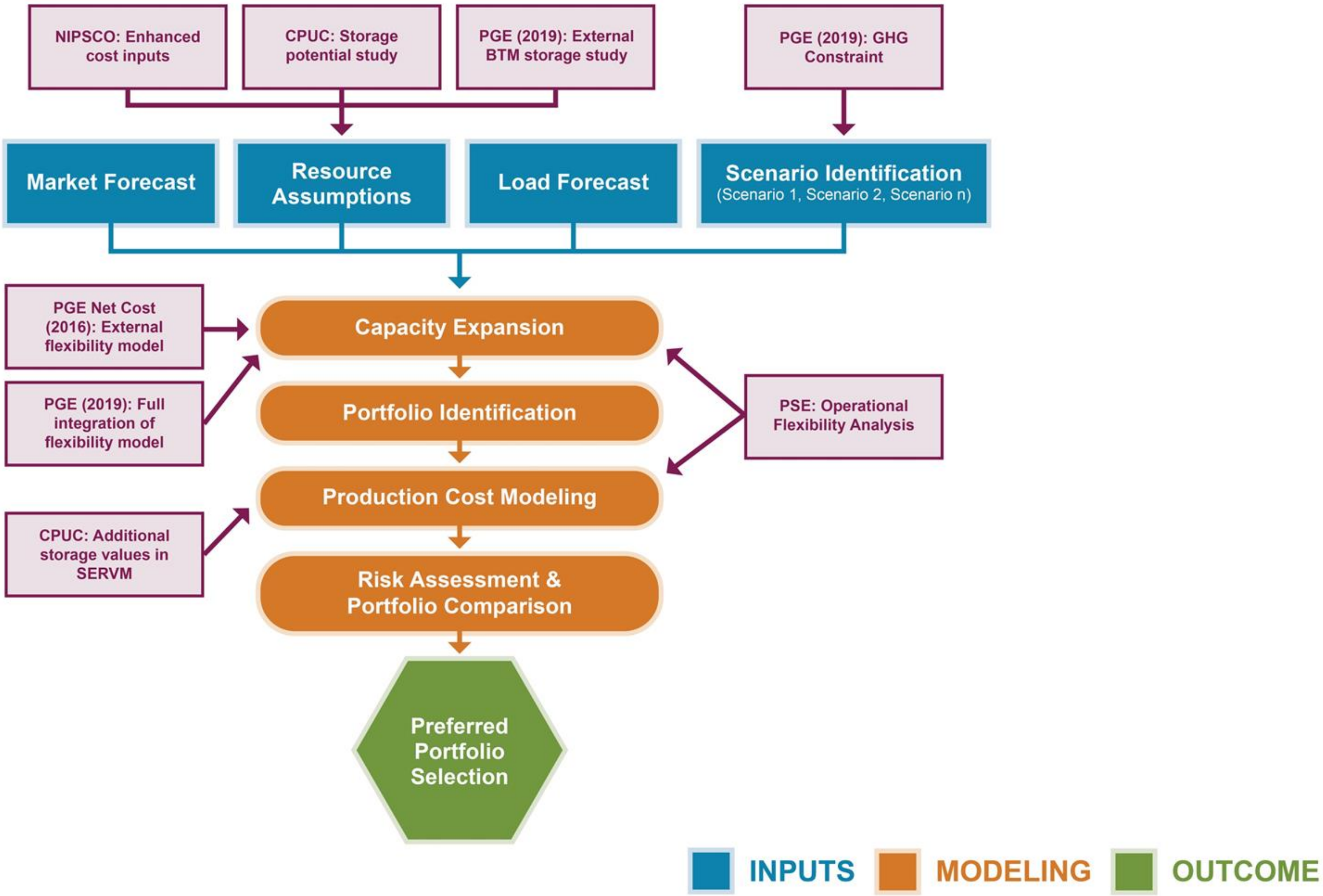
In addition to looking at intra-hour flexibility needs, PGE also identified high-demand winter mornings during which the utility's reserve margin would be stretched and value of flexible resources would persist for multiple hours.

- The preferred portfolio selected only 6-hour batteries (37 MW)
- The preferred portfolio also selected 200 MW of new pumped storage hydropower, though the constraint against new GHG-emitting resources appears to be the deciding factor

Finally, PGE included BTM storage as a resource option in its capacity expansion model, using projected utility incentives (informed by an external study) as the modeled cost

- Selected 4 MW of BTM storage

Summary: Multiple Avenues for Improving Storage's Representation in IRPs



Final Thoughts

Utility innovation in modeling energy storage is accelerating, but not dispersing

- Much of the activity centered in the west, where utilities have made evolutionary changes over the last two or three planning cycles
- Limited dissemination to other IRP states in the southeast
  - Several southeastern utility IRPs have selected storage in recent cycles (Duke Energy, Georgia Power, Florida Power & Light, etc.), but IRPs are lean on analytical details

IRP transparency is improving, but there is still room for improvement

- As IRPs form the "paper trail" for subsequent investments and rate recovery, utilities are increasingly providing extensive narratives about modeling approaches and conclusions
- Where storage is selected without supporting modeling, the process breaks down and regulatory processes are challenged
- Cost assumptions remain an area of limited transparency

Thank you

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