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Integrating Cambium Marginal Costs into Electric-Sector Decisions

Opportunities to Integrate Cambium Marginal Cost Data into Berkeley Lab Analysis and Technical Assistance

Joachim Seel, Andrew Mills

November 2021

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Integrating Cambium Marginal Costs into Electric-Sector Decisions

Opportunities to Integrate Cambium Marginal Cost Data into Berkeley Lab Analysis and Technical Assistance

Prepared for the
Office of Energy Efficiency & Renewable Energy
Strategic Analysis
U.S. Department of Energy

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Acronyms and Abbreviations

ACC	Avoided Cost Calculator
AEO	Annual Energy Outlook
AS	Ancillary Services
BA	Balancing Area
BTM	Behind The Meter
BTO	Building Technologies Office
CAISO	California Independent System Operator
CPUC	California Public Utilities Commission
DER	Distributed Energy Resource
DOE	Department of Energy
DPV	Distributed Photovoltaics
DR	Demand Response
DWL	Deadweight Loss
EE	Energy Efficiency
EIA	Energy Information Administration
EMM	Electricity Market Module
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
GEB	Grid-interactive Efficient Building
GMLC	Grid Modernization Lab Consortium
GTO	Geothermal Technologies Office
IOU	Investor-Owned Utility
IRP	Integrated Resource Planning
ISO-NE	Independent System Operator New England
MISO	Midcontinent Independent System Operator
NYISO	New York Independent System Operator
OE	Office of Electricity
OEA	Operating Envelope Agreement
O&M	Operations and Maintenance
ORDC	Operating Reserve Demand Curve
PV	Photovoltaics
PJM	PJM Interconnection
ReEDS	Regional Energy Deployment System
S2G	Solar-to-Grid Report
SCEC	Security-Constrained Economic Dispatch
SCUC	Security-Constrained Unit Commitment
SETO	Solar Energy Technologies Office
SPP	Southwest Power Pool
TOU	Time of Use

TSV	Time-Sensitive Valuation
UPV	Utility-scale Photovoltaics
VRE	Variable Renewable Energy
VTO	Vehicle Technologies Office
WETO	Wind Energy Technologies Office
WTMR	Wind Technologies Market Report

Executive Summary

NREL's Cambium tool generates forward-looking simulations of marginal wholesale electricity costs associated with NREL's Standard Scenarios. The scenarios include growing shares of variable renewable energy (VRE, i.e. wind and solar), among other power sector assumptions, between 2018 and 2050. The tool's primary output—hourly costs at more than 130 balancing areas—could serve as public and transparent data source that supports electric-sector decision-making processes across the U.S. Berkeley Lab conducts a large range of analyses that use historical and forward-looking wholesale electricity prices to inform electric-sector decisions. In this report, Berkeley Lab uses its expertise to evaluate the Cambium cost data. We compare Cambium data with historical wholesale prices for the year 2018 and other modeled prices for the year 2030. We then present eight case studies in which Berkeley Lab researchers use Cambium data to replicate previous analyses based on other price datasets. We describe where primary findings and underlying key price dynamics align or differ, and highlight possible novel insights from the Cambium data. Finally, we qualitatively evaluate the suitability of Cambium costs in ten additional Berkeley Lab studies, though a direct comparison with alternative price data was not feasible at this time. The goal is to inform how DOE program offices may be able to use this cohesive dataset themselves or in their sponsored research projects, and to highlight what improvements to Cambium may make it even more useful.

Overall, we find that insights from several previous Berkeley Lab studies that use other price data are reproduced with the Cambium data. While there are examples of significant differences in the *magnitude* of evaluated grid benefits, the *directionality* of findings are generally consistent. Cambium costs appear to be very promising for use in ongoing or planned studies at Berkeley Lab or for other DOE sponsored research.

Access to hourly data that reflect changing loads and marginal costs across days and seasons is highly useful for time-sensitive valuation research. Of great value is also the broad geographic scope of the data across the entire continental U.S. while providing granular balancing area-level results. Transparent long-term projections to 2050 with bi-annual resolution allow us to capture value streams across the entire life-cycle of a particular resource, accounting for the overall system evolution. The availability of multiple scenarios spanning a range of technology assumptions is very useful for sensitivity analyses. Inclusions of certain policy constraints such as renewable portfolio standards provide a realistic floor to future VRE expansion. We also value the availability of supplemental data such as technology-specific generation and marginal carbon emissions data.

Further improvement to some aspects of the Cambium data can make it even more useful. For example, Cambium underrepresents price variability. Specifically, the model does not allow for negative prices (which commonly occur during times of high wind and solar), and it underrepresents price spikes during scarcity events. Cambium appears to not fully capture reductions in marginal costs in the middle of the day at high solar penetrations or at night with higher wind penetrations. It also does not reflect high prices that can result from market instruments such as ERCOT's Operating Reserve Demand Curve

(ORDC). The impact of underrepresenting price variability is that value of generation flexibility is biased low, compared to the value calculated based on recent empirical wholesale price patterns. This may cause battery storage, or other flexible generation operations, to be undervalued within Cambium. It may also cause estimates of solar and wind integration costs to be biased low. Relatedly the current weather representation underestimates uncommon but increasingly more frequent extreme weather events with important implications for reliability and price spikes. Figure ES - 1 below illustrates the general importance of price variability qualitatively with a number of case studies that are discussed in more detail in Sections 4 and 5 of the report.

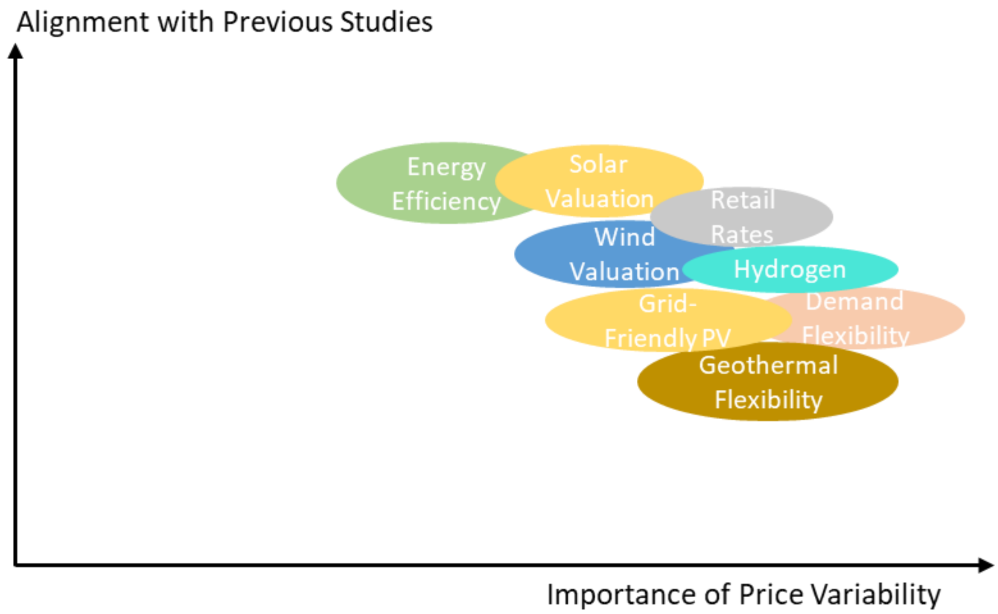

Figure ES - 1. Impact of Price Variability on Consistency of Findings

Cambium's capacity costs deviate at times strongly from empirical market outcomes, having more realistic data from projected capacity auctions would be valuable. We also find that the allocation of capacity costs over 40 hours of the year can lead to strong (irregular) variability in total end-user costs, it would be useful to further assess how this aligns with current standard practices for most utilities. We find that a distinction of transmission and generation capacity costs would be useful in some of our valuation studies, as well as an inclusion of baseline transmission and distribution costs that would be required to model all-in retail costs.

It appears that carbon constraints are included in the capacity expansion modeling of ReEDS but not in the unit-commitment modeling. Carbon permit costs from cap and trade markets like California are thus not included in the reported marginal energy costs, thereby potentially underestimating future marginal cost levels. The value erosion of solar and wind projects at higher penetration levels seem to be currently underestimated, though it is unclear whether this is driven by modeled flexibility additions. The overall representation of storage seems a bit puzzling as energy price variability does not change from MidCase scenario to the LowBatScenario – this seems to be an area of particular relevance given the growing deployment of storage resources. More generally it would be useful to incorporate a few additional scenarios into the suite of standard scenarios that allow for analyses of pressing issues (near-term carbon-neutrality in the electricity sector, large-scale building and transportation electrification, economy-wide carbon neutrality by 2050). We found it is sometimes difficult to associate Cambium scenarios with other scenarios that rely on different weather or load data. One should consider making associated weather data that drive energy consumption or weather-related generation more easily accessible (e.g. geographically resolved wind speed at multiple hub heights), as well as other input assumptions (e.g. natural gas prices). Finally, we would find an even finer geographic representation of Cambium's results to mid-size utilities instead of its current BA-level valuable for technical assistance applications.

In a few situations we found the Cambium prices data not suitable for our analyses. As explicitly acknowledged by NREL, the current representation of ancillary service (AS) prices is not in line with empirical market outcomes. A reliance on current Cambium AS price forecasts may impede cost-effectiveness assessments of technologies like PV+storage. We also found it infeasible to forecast power purchase budgets for utilities with the Cambium data as load-serving entities don't typically rely exclusively on spot-market power purchases. Reporting average costs in addition to marginal costs may be useful for such research.

More generally, our evaluation suggests there are many promising applications of the Cambium data beyond existing Berkeley Lab projects. There is a great wealth in available data and to some extent we have only scratched the surface of possible research applications. The Cambium data seems very suitable for the use by multiple DOE program offices that can leverage this cohesive dataset themselves or in their sponsored research projects.

1. Introduction

NREL's Cambium tool generates forward-looking simulations of marginal wholesale electricity costs ("Cambium costs") associated with NREL's Standard Scenarios. The scenarios include growing shares of variable renewable energy (VRE) between 2018 and 2050. The tool's output—hourly marginal costs at more than 130 balancing areas (BAs)—could serve as public and transparent data source that supports electric-sector decision-making processes across the U.S. Berkeley Lab conducts analyses that use historical and forward-looking wholesale electricity prices to inform electric-sector decisions. In this report, Berkeley Lab uses its expertise to evaluate the Cambium cost data. The goal is to inform how DOE program offices may be able to use this cohesive dataset themselves or in their sponsored research projects, and to highlight what improvements to Cambium may make it even more useful.

Section 2 summarizes Berkeley Lab's use of historical and forward-looking wholesale electricity price data in Berkeley Lab's recent electric-sector decision research projects. Berkeley Lab uses empirical wholesale electricity prices for energy, capacity, and ancillary service (AS) prices from the seven wholesale markets and price approximations for other balancing authorities outside of those markets. In collaboration with LCG Consulting, Berkeley Lab also developed a common set of wholesale electricity price projections for the year 2030 from detailed wholesale market simulations with low and high VRE scenarios.

Section 3 compares marginal energy, capacity, and ancillary service cost dynamics from Cambium to empirical price data from historical years (with a particular focus on 2018) and other modeled prices for 2030 scenarios. We find that average empirical energy prices in 2018 were lower than estimated by Cambium, and had consistently more geographic and temporal variation than the modeled costs. Similarly, Cambium's annual capacity costs fall within a narrower band and are often lower than empirical prices. Cambium cautions to use its estimated ancillary service costs which are indeed much lower than empirical prices in 2018.
We also compare Cambium data with modeled electricity prices for the year 2030 by LCG for select markets and find that the overall range in average marginal costs across scenarios are similar in both tools, with the exception of CAISO. In both data sets the cost spread increases with growing VRE shares. While shares of very low-priced hours align well, Cambium has less diurnal cost variation. Both models use similar methods to estimate capacity costs, but Cambium's results are often lower. As Cambium allocates capacity costs to fewer hours, the hourly capacity cost adders are in contrast higher than for LCG.

Section 4 presents eight case studies in which Berkeley Lab researchers use Cambium data to replicate previous analyses based on other price datasets. We describe where primary findings and underlying key price dynamics align or differ, and highlight possible novel insights from the Cambium data.

Section 5 qualitatively evaluates the suitability of Cambium marginal costs in ten additional Berkeley Lab studies, though a direct comparison with alternative price data was not feasible at this time.

2. Role of Wholesale Price Data in Berkeley Lab's Work

Table 1. Berkeley Lab projects that use wholesale price data to inform electric-sector decisions

DOE Office	Research Project	Description	Price Data Used in Analysis
Section 4 Case Studies: Comparative Evaluation of Cambium Data			
SETO	Solar-to-Grid	Valuation of empirical solar projects	Energy (nodal) and capacity (zonal) prices in 7 ISOs and 10 additional BAs, 2012-2019
SETO	Grid-Friendly Photovoltaics (PV)	Valuation of hypothetical solar project designs, including storage	Historical energy prices (nodal) for 7 ISOs, modeled LCG price data for 2030 for 4 ISOs
WETO	Wind Tech Market Report	Valuation of empirical wind projects	Energy (nodal) and capacity (zonal) prices in 7 ISOs, 2008-2019
EERE Strategic Analysis	High VRE Impact on Demand-Side Decisions	Valuation of Energy Efficiency (EE) portfolios, retail rate designs, and hydrogen production	Modeled LCG price data for 2030 for 4 ISOs
GTO	Geothermal Flexibility	Valuation of flexible geothermal operations	Historical energy prices (nodal) for CAISO, modeled LCG price data for 2030 for CAISO
SETO	PUC Analytical Support	Improving the Representation of DERs in Utility Integrated Resource Planning (IRP)	Indiana utility IRP energy price projections for 2020 and 2030
Section 5: General Assessment of Cambium Data			
BTO	Time-sensitive Valuation (TSV) EE Calculator	Valuation of EE measures and programs	Cambium BA-level energy and capacity costs, marginal carbon emissions
BTO	Scout Model	Valuation of EE and Flexibility Measures	Cambium BA-level total end-user costs, carbon emissions
BTO	Grid-Interactive Efficient Building (GEB) Roadmap	Valuation of EE and Demand Flexibility Measures	Cambium energy, capacity, AS costs, carbon emissions for 22 regions
N/A (California PUC)	Demand-Response (DR) Potential Study	Project DR quantity, costs and value in California	Wholesale electricity cost and carbon emissions forecast by CPUC
BTO/SETO/ VTO/OE	Connected Communities	Valuation of EE and Flexibility Measures that maximize DER self-consumption	*Potentially* Cambium energy, capacity and AS costs at multiple locations throughout U.S.
SETO/OE (GMLC)	Multi-DER Rate Impacts	Valuation of DPV and EE system and customer benefits according to multiple retail rate designs and marginal system costs	Cambium energy and capacity costs
SETO	Distributed PV (DPV) +Storage Net Billing	Comparison of alignment of net-billing retail rates with system value	Historical empirical data and Cambium energy, capacity, AS costs, carbon emissions at multiple BAs
EERE Strategic Analysis	Future Drivers of Retail Rates	Forecasting electric utility fuel and purchased power budgets	Cambium energy costs
SETO	SEIN Utility-scale PV (UPV) Feeder Integration	Valuation of multiple UPV designs, including storage	Cambium energy costs for Rhode Island, *potentially* capacity and AS costs
WETO	Big Adaptive Rotors	Valuation of hypothetical wind project designs	Historical energy prices (nodal) for 7 ISOs, modeled LCG price data for 2030 for 4 ISOs

The purpose of this section is to demonstrate the range of Berkeley Lab studies that use wholesale prices to inform electric-sector decisions and describe the sources of wholesale price data. Table 1 above summarizes recently completed or ongoing projects at Berkeley Lab that use (or could use) historical or forward-looking wholesale prices to inform electric-sector decisions.

2.1 Historical Prices

Berkeley Lab uses empirical wholesale electricity prices for energy, capacity, and AS in many studies of electric-sector decisions. Hourly energy prices in the seven organized wholesale markets are either from representative trading hubs or individual pricing nodes (with more than 50,000 nodes in the U.S). Hourly AS price series are reported at the system level or in distinct geographic zones. Berkeley Lab uses either interface price nodes or Federal Energy Regulatory Commission (FERC)-reported system lambda data to approximate energy prices in non-ISO balancing authorities. We estimate capacity value of resources based on capacity price data with zonal granularity in regions with centralized capacity auctions. For regions that do not hold centralized capacity auctions we estimate capacity prices using bilateral capacity trades as reported by FERC or other public agencies (e.g. California's Public Utility Commission).

2.2 Forward-looking 2030 Scenario Price Data

In collaboration with LCG Consulting, Berkeley Lab developed a common set of wholesale electricity prices from detailed wholesale electric market simulations with low and high VRE scenarios (named LCG prices in the remainder of this report). We investigated implications of VRE-driven price dynamics for long-lasting investment and program design decisions in the electric sector (Seel et al. 2020). The simulations focused on the year 2030 in four regions—the Southwest Power Pool (SPP), New York Independent System Operator (NYISO), California Independent System Operator (CAISO), and Electric Reliability Council of Texas (ERCOT)—across four scenarios: (1) a low VRE penetration scenario that freezes renewable energy shares at 2016 levels, (2) a high solar scenario (featuring 30 percent solar energy and at least 10 percent wind), (3) a high wind scenario (featuring 30 percent wind energy and at least 10 percent solar), and (4) a balanced scenario (20 percent wind and 20 percent solar).
The wholesale price simulation leverages two commercial tools developed by LCG Consulting. These tools were chosen because of their credible representation of long-run marginal cost that allow for hourly granularity of energy and ancillary service prices, along with consistent capacity prices. The credibility of LCG Consulting is based on their history of frequent usage by decision makers for asset valuation and planning.

For each scenario, the analysis first used a capacity expansion model and optimization tool, Gen-X,[1] to find the least-cost combination of generation additions and retirements while satisfying system constraints. In this analysis, Gen-X was only used to find the expansion plan for non-VRE resources, as the VRE levels were specified exogenously. Capacity expansion decisions (including the option to retire existing generation) were based on social cost minimization, including the variable and ongoing fixed

[1] For more documentation, see LCG Consulting (2017a).

cost of all generators and up-front capital costs for new generators. Emission costs for nitrogen oxides (NO_x), sulfur oxides (SO_x) in NYISO and ERCOT, and carbon dioxide (CO_2) in CAISO ($53/ton) and NYISO ($24/ton) were based on exogenous projections of permit prices by planning entities in each of the four regions. The emissions costs affect the marginal costs of generators and therefore influence the market clearing prices for electricity.

After establishing the generation portfolio in each of the scenarios, we subsequently used the UPLAN Network Power Model to simulate hourly zonal electricity prices and marginal emission rates.[2] This model, a security-constrained unit commitment (SCUC) and security-constrained economic dispatch (SCED) tool developed by LCG Consulting, co-optimizes energy and AS markets and allows for a large range of input data for load, generation, and the transmission network. The energy and AS prices were then used to simulate rational bids for a capacity market. One consequence of the sequential nature of the capacity expansion modeling followed by the detailed market modeling is that the capacity prices reflect the largest unmet fixed operation and maintenance (O&M) costs of any unit in the market, or the largest unmet fixed capital costs and fixed O&M costs of new units built to meet the planning reserve margin in Gen-X. We allocated the capacity prices in equal parts to the top 100 peak net load hours for each respective region and add them to the energy prices for our decision analyses. For more information see Seel, Mills, and Wiser 2018.

3. Comparison of Cambium with Other Berkeley Lab Price Datasets

The purpose of this section is to compare Cambium marginal costs to other Berkeley Lab datasets using high-level quantitative metrics. It is important to acknowledge that the overlap in scenario definition, year coverage, and model assumptions is not perfect.

3.1 2018 Wholesale Prices

Here historical wholesale prices from 2018 are compared to Cambium's 2018 marginal costs. Historical energy and ancillary service prices are from one major trading hub in each region while Cambium costs are from BAs near the major trading hubs.[3]

3.1.1 Energy Prices

Average energy prices in 2018 match well for some regions (~$1/MWh difference in NYISO) and less well in others (e.g., Cambium overestimates SPP prices by $8/MWh or 31%). In contrast, Cambium shows consistently less geographic and temporal variation than historical prices. Historical average prices across ISOs varied between SPP ($25/MWh) and ISONE ($44/MWh). In Cambium average costs

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[2] For more documentation see LCG Consulting (2017b).

[3] We selected the following ISO hubs and associated ReEDS areas: CAISO: SP15 / 10, SPP: SPP-South / 50 , ERCOT: North / 63, MISO (Midwestern Independent System Operator): Indiana/ 105 , PJM: Western Hub/ 112, ISO-NE (Independent System Operator New England): Internal Hub H/ 129, NYISO: HUD VL Zone G/ 127

across most ISOs cluster around $33/MWh. Cambium especially lacks larger price spikes (Figure 3-A), having a maximum marginal cost of $65-85/MWh in most markets compared to historical maximum prices of $475-1225/MWh. Cambium shows some high costs at $260/MWh in ERCOT and ISONE, although this is still far below historical high prices of $2800/MWh and $2450/MWh, respectively.

Similarly Cambium does not capture low price periods well, as only 1% of all hours in 2018 or less have marginal costs under $20/MWh. Cambium particularly misses periods of low or negative prices in CAISO and SPP. In those region 8-11% of hours had prices below $10/MWh and 4% of prices were negative. Cambium's cost spread is narrower. The annual standard deviation of marginal costs in Cambium was $4-9 /MWh in most markets and $20/MWh in ISONE whereas the standard deviation was between $20-$55/MWh in historical prices. Nodal-level prices that incorporate additional local transmission constraints have even more variation than the historical hub prices.

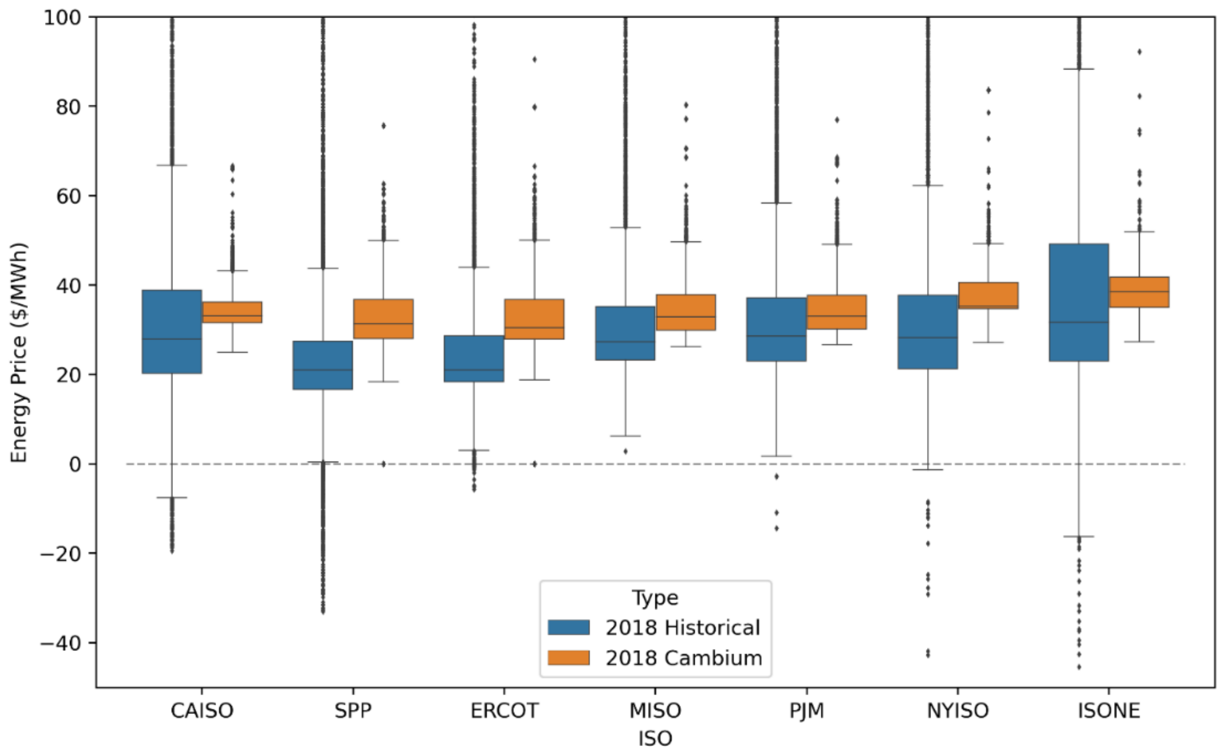
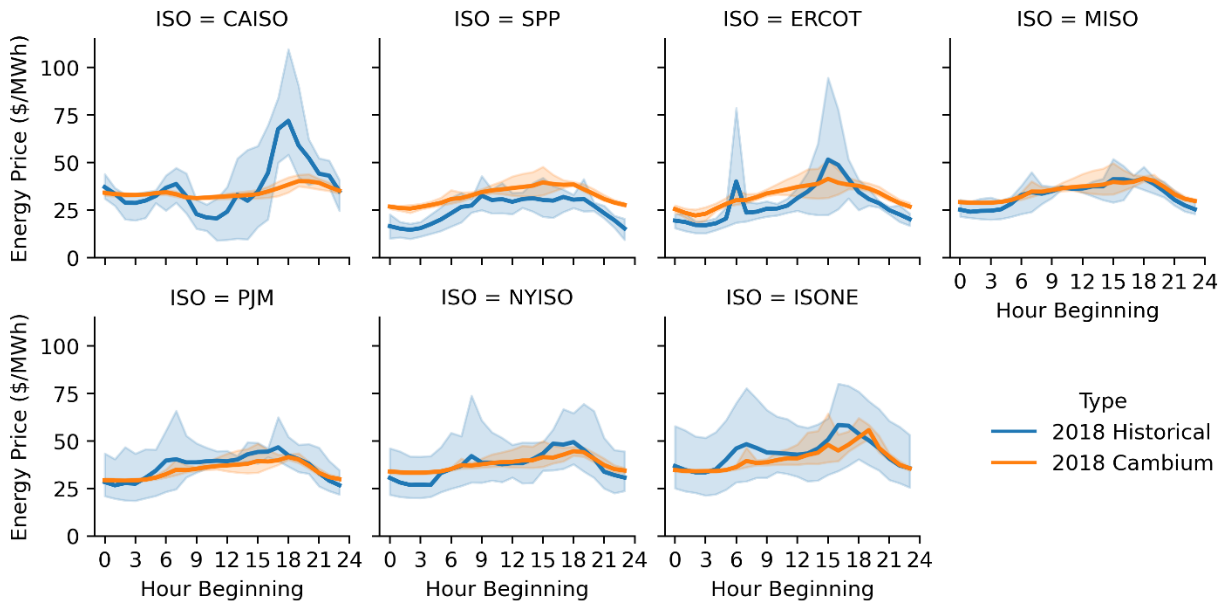


Figure 3-A Distribution of Energy Prices at Major Trading Hubs in 2018, Historical vs. Cambium

The Cambium marginal costs show modest variation of average costs over the course of the day (Figure 3-B). Cambium diurnal costs track historical profiles in MISO, NYISO, or PJM, where prices peak in the late afternoon and fall overnight. On the other hand, Cambium misses the solar-driven diurnal price variation in CAISO and price declines during the night hours in wind-rich SPP and ERCOT.

Diurnal price profiles also vary by season. Prices rise across all hours in the winter in ISONE (top edge of shaded area) or fall in the spring in CAISO (bottom edge of shaded area). Cambium, in contrast, shows only modest variation in the diurnal profiles over the course of the year.



Note: Shaded areas describe seasonal range of average price profiles

Figure 3-B Diurnal Energy Prices at Major Trading Hubs in 2018, Historical vs. Cambium

3.1.2 Capacity Prices

Cambium estimates capacity costs as the shadow price of Regional Energy Deployment System's (ReEDS) capacity constraints (in $/MW-yr). This cost is then allocated to the top 40 net-load hours at the busbar or enduser location as a capacity cost adder (in $/MWh). Cambium's firm capacity costs represent the least cost of building new capacity, holding old uneconomic capacity, or building new inter-BA transmission. Figure 3-C compares those values with Berkeley Lab's estimate of historical capacity prices for 2018. [4]

The $20 to $40/kW-yr range of Cambium capacity costs for 2018 is relatively narrow compared to the range of $2 (MISO) to $102/kW-yr (ISO-NE) estimated by Berkeley Lab. Cambium also estimates capacity costs for the energy-only market in ERCOT since Cambium uses shadow prices to the capacity constraints rather than modeling capacity market outcomes. Cambium's capacity costs are lower than historical 2018 capacity prices in all ISOs but MISO. One difference that may lower Cambium costs is that it allows new transmission investments to satisfy capacity constraints, whereas new transmission is not included in traditional capacity auctions.

[4] Berkeley Lab's estimates are derived either from centralized capacity auctions or from bilateral capacity transactions reported in FERC electronic quarterly reports. For more information see Appendix C in (Mills et al. 2021).

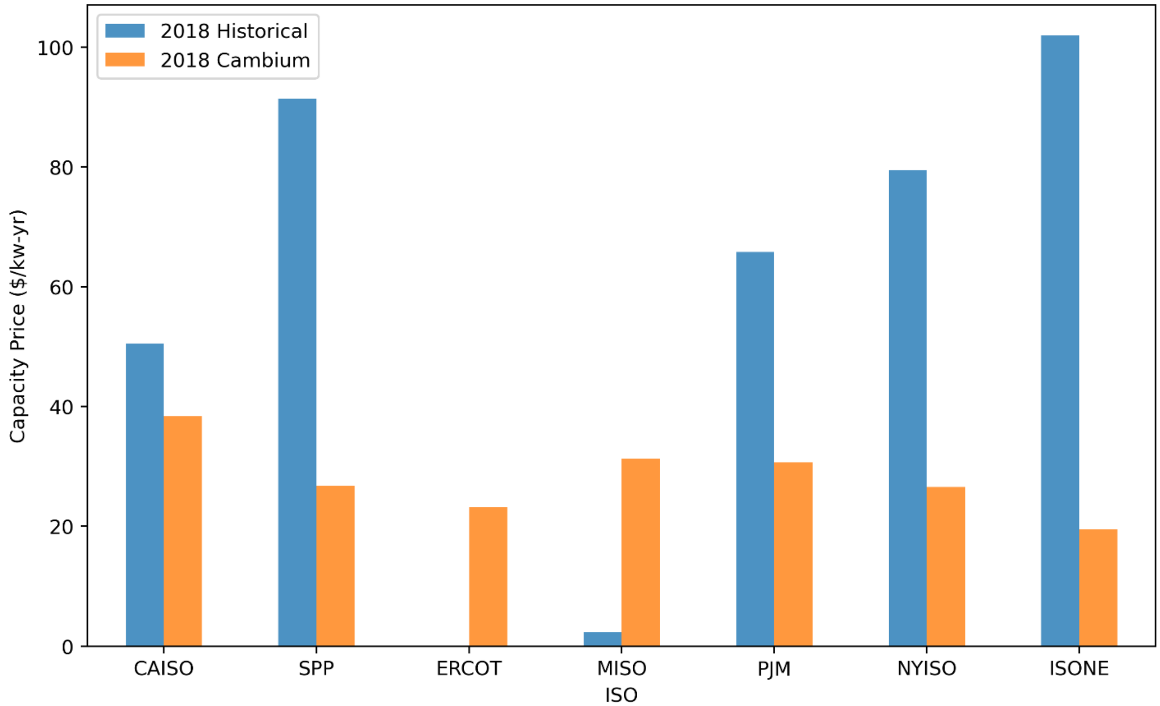


Figure 3-C Capacity Prices at Major Trading Hubs in 2018, Historical vs. Cambium

3.1.3 Ancillary Service Prices

Cambium includes three operating reserve products that are consistent across the entire US: regulation, spin, and flexibility. Costs are reported both as shadow prices for each product and associated busbar and enduser cost. Cambium assumes that regulation services can be provided without operational costs, leading to shadow prices that are zero as long as residual online capacity is available.

Average historical regulation prices in 2018 range between $10/MWh (MISO) and $28/MWh (ISO-NE), accompanied by large price spikes that reach up to $2000/MWh in ERCOT or $2450/MWh in ISO-NE.[5] Average Cambium regulation marginal costs ($0-$2/MWh) are much lower than historical prices, and have lower volatility (Figure 3-D). Cambium regulation costs reach $175/MWh in ISO-NE and are lower than $100/MWh in other markets. Only SPP and ERCOT have non-zero costs for more than 25% of the year. Historical diurnal price variations for regulation products are less pronounced than energy price variations, but often show an early morning and late afternoon peak, especially in ERCOT. Non-zero Cambium regulation costs, to the extent that there are any, often occur within these time windows, but are much smaller in magnitude.

Historical prices for spin products are lower than regulation prices, averaging $3-$5/MWh except in ERCOT where average prices are $18/MWh. Similar to regulation prices, spin prices exceed $2000/MWh in some markets in 2018, while Cambium's estimated marginal costs are lower (again $0-$2/MWh).

[5] Some markets include a regulation up and regulation down price (CAISO, ERCOT, SPP). In these markets, we take greater of the two prices in each hour as the "regulation" price to compare to Cambium prices.

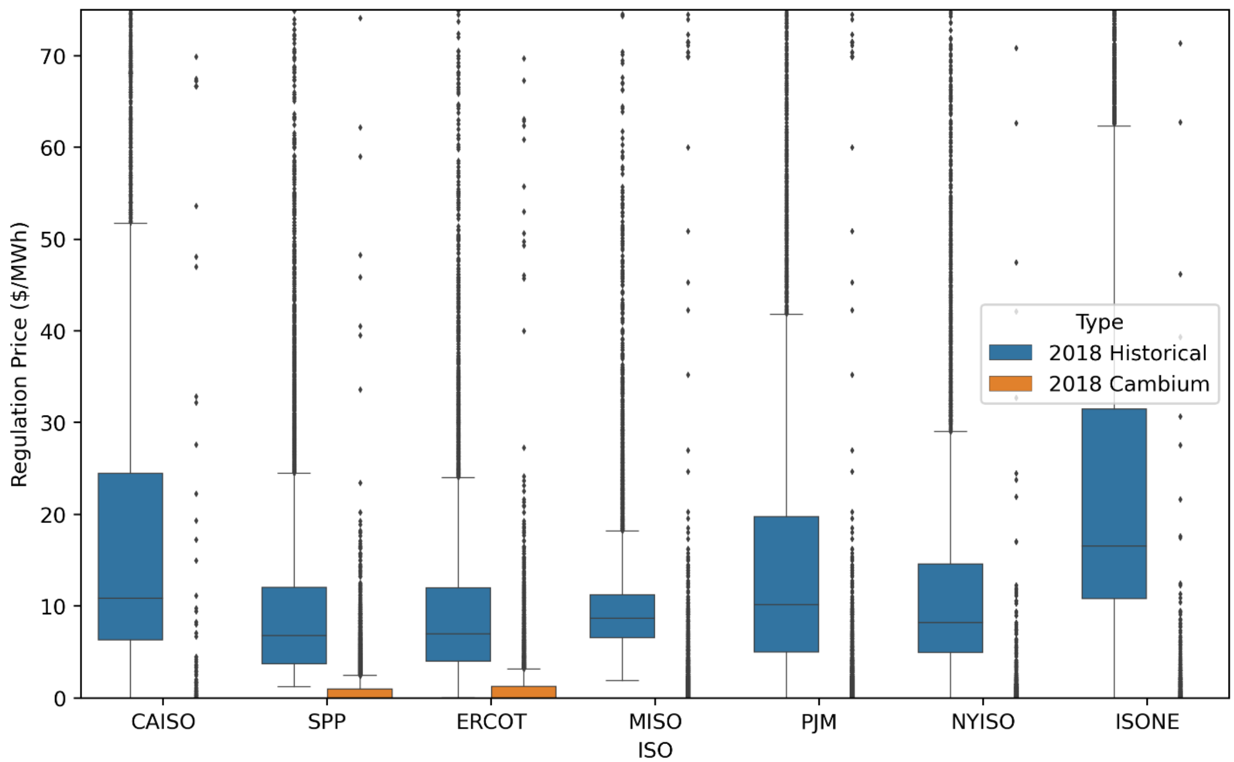


Figure 3-D Regulation Prices at Major Trading Hubs in 2018, Historical vs. Cambium

3.2 2030 LCG Prices

Here we compare modeled wholesale prices for 2030 in CAISO, ERCOT, SPP and NYISO between Cambium and LCG.[6] Because it is not always straight-forward to compare hourly prices of four ISOs, four LCG scenarios, and five Cambium scenarios, we will focus only on high-level observations.

3.2.1 Energy Prices

The overall range in average marginal costs across scenarios are similar in both models, with the exception of CAISO. We presume average prices in CAISO are higher in LCG's scenarios because of a carbon cost adder for this market of ~$50/ton CO2. Average wholesale marginal energy costs decrease with increasing VRE penetration in both models: LCG prices decrease by $0.2-$0.9/MWh per additional % of VRE load share while Cambium's ERCOT and SPP marginal costs[7] decreased by $0.3-$0.4/MWh per additional % of VRE. The decrease in Cambium's marginal costs is in the center of the range estimates reported in the academic literature ($0.1-$0.8/MWh) (Wiser et al. 2017).

[6] The LCG price series represent ISO-wide average prices as few intra-ISO transmission constraints were included in the model. For comparison, we average Cambium prices across all BAs in the ISO.
[7] NYISO and CAISO did not have sufficient variation in 2030 VRE penetration to yield meaningful results

Table 2. Comparison of Average Annual Energy Costs Across Scenarios, LCG vs. Cambium

Source	CAISO	SPP	ERCOT	NYISO
LCG	$42-57	$23-31	$25-32	$24-40
Cambium	$30-33	$17-29	$25-32	$27-30

In both datasets the marginal cost spread increases with growing VRE shares (standard deviation of LCG data $9-$19/MWh, Cambium data $9-$15/MWh). LCG's prices include an operating reserve demand curve (ORDC) that leads to high scarcity price adders in ERCOT's energy-only market, allowing prices to reach the $9000/MWh price ceiling. Cambium does not include this, leading to a much lower standard deviation of $15/MWh in the LowRECost scenario compared to LCG's $130/MWh standard deviation in the High Solar scenario.

The share of very low cost hours in Cambium prices align well with LCG's estimates, with the exception of SPP. In the LowRECost and LowWindCost scenarios, Cambium's wholesale marginal energy cost fall under $5/MWh in up to 7% of all hours in NYISO, 11% in CAISO, 12-17% in ERCOT. For SPP, periods of low cost exceed 33% of hours in Cambium as VRE shares reach 100-105% of load.

The Cambium data has less diurnal cost variation across scenarios than the LCG data (Figure 3-E). One reason is that solar penetration does not significantly vary across Cambium scenarios, particularly for CAISO and NYISO. In ERCOT, Cambium's solar penetration reaches 19% in the LowRECost scenario in 2030, never achieving LCG's stipulated 30% solar penetration. Hence, marginal cost declines during the middle of the day followed by high cost peaks in the evening are less pronounced. In SPP, solar penetrations increase from 24% in the LowWindCost to 36% in the LowRECost scenario and midday prices decline visibly by nearly $10/MWh. Interestingly Cambium's LowBatCost scenario brings only minimal change compared with the MidCase scenario and does not mute diurnal price variations.

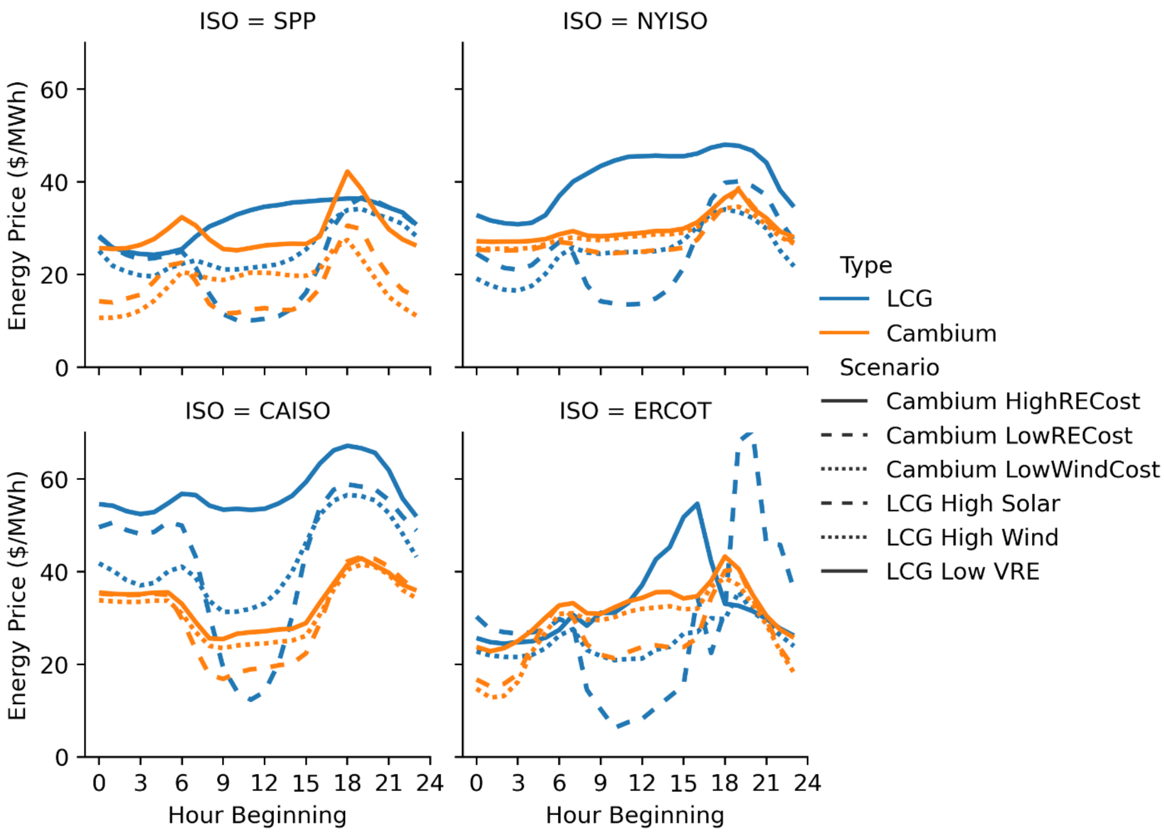


Figure 3-E Annual Diurnal Marginal Energy Costs in 2030 for Select ISOs, LCG vs. Cambium

3.2.2 Capacity Prices

The method used to estimate LCG's capacity prices is conceptually similar to Cambium's method. Both represent the marginal cost of building new capacity or holding existing capacity to meet reserve requirements.[8] Cambium's capacity costs are often $10-$30/kW-yr lower than LCG's despite overall similar energy costs (Figure 3-F). In the LCG data VRE growth tends to lead to higher capacity prices that compensate for decreased energy prices. This is not consistently observed in the Cambium data.

Even with lower capacity costs, the hourly capacity cost adders will be higher for the Cambium costs than the LCG prices. This occurs because Berkeley Lab allocates LCG's capacity prices across the top 100 net-load hours, while Cambium choses only the top 40 net-load hours, resulting in higher capacity cost adders.

[8] LCG's annual average capacity prices allow all competitive generators needed to meet a planning reserve margin to recover their ongoing fixed and variable operation and maintenance costs and the annualized capital costs of new CCGTs and CTs beyond the revenue earned in the energy and ancillary service markets. Its capacity prices reflect the additional revenue, beyond earnings in the energy and ancillary service markets, needed to ensure that generators required to meet the planning reserve margin cover their costs in a consistent manner across regions. In contrast to Cambium, new inter-BA transmission costs are not included.

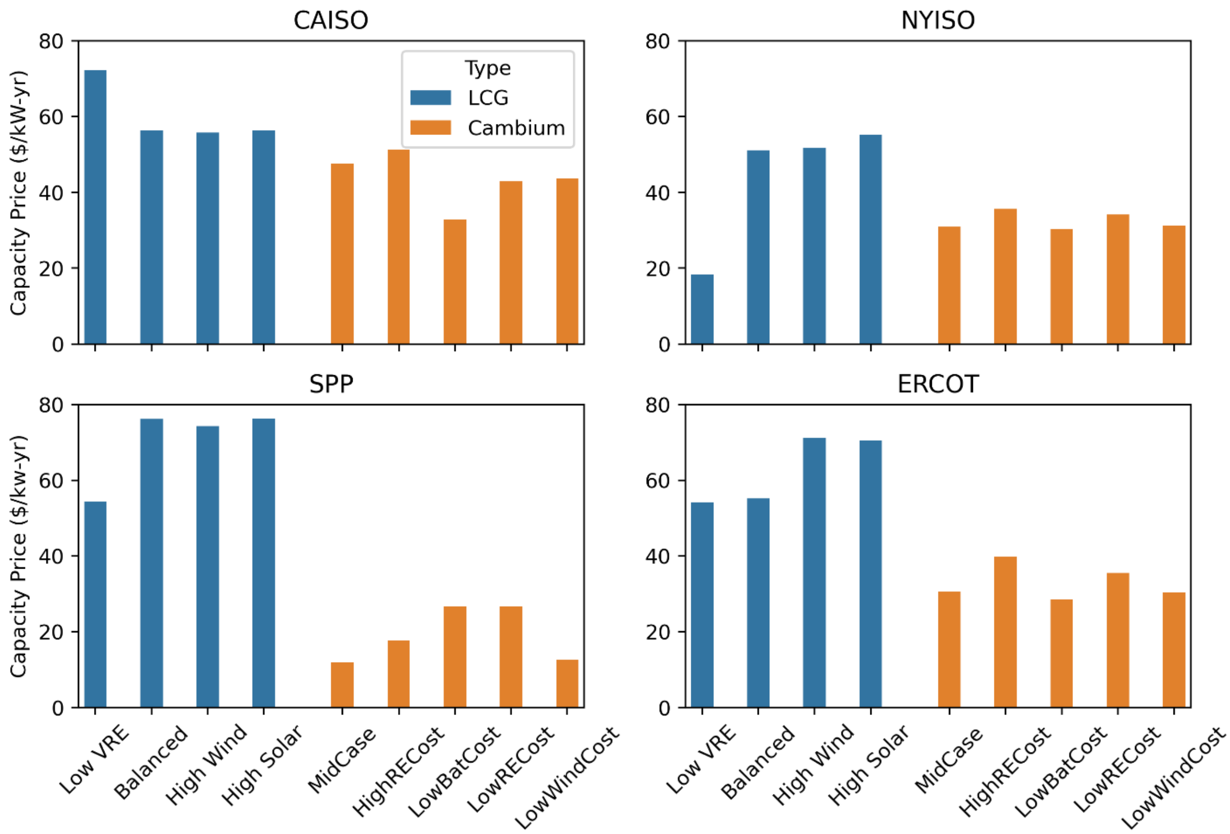


Figure 3-F Capacity Costs in 2030 for Select ISOs, LCG vs. Cambium

4. Evaluation of Cambium Costs in Select Case-Studies

The purpose of this section is to evaluate whether insights from previous Berkeley Lab analysis based on historical or forward-looking prices are reproduced using Cambium marginal costs. For each case study, Cambium costs are substituted into the existing analysis code to generate alternative results. In particular, Cambium 2018 costs are used in studies based on historical prices, while Cambium 2030 costs are used in studies based on LCG prices. Cambium locations and scenarios are chosen to best match what was used in the original Berkeley Lab analysis.

For each of the studies in this section, we summarize the original key insights of the Berkeley analysis, similarity of Cambium results, key price dynamics driving results, and novel insights due to the use of Cambium data.

4.1 Solar Valuation at Increasing Penetrations

Lead Contact: Jo Seel, jseel@lbl.gov

What was the key insight from the original Berkeley Lab study? Berkeley Lab analyzed solar's historical wholesale energy and capacity value leveraging empirical solar profiles and wholesale price data for 7 ISOs and 10 select utilities (Solar-to-Grid or S2G data, Mills et al. 2021), and solar's market value in 2030 with LCG data. With both datasets Berkeley Lab found that solar's energy value is larger than the capacity value and that solar's value relative to a flat block of power (value factor) is higher at low penetrations but declines with higher penetration. Solar's combined energy and capacity value in 2019 ranges from \$30-\$60/MWh depending on region. Solar is more valuable than a flat block of power in all locations except CAISO, AZPS, and NEVP.

How similar are the results from the Cambium costs? Overall ranges for solar value in 2018 are similar in Cambium (\$35-50/MWh) and S2G (\$30-65/MWh), though average values can deviate in specific regions (Figure 4-A). For example, Cambium estimates \$20-25/MWh less capacity value in FPL and SPP, but \$5-\$10/MWh more energy value in CAISO, SPP, AZPS, NVEP, PSCO, and FPL. Solar penetration levels are roughly equal between the S2G and Cambium data. Most regions have similar solar value factor estimates, but value erosion in the high penetration regions of CAISO, APZS, NEVP, and PNM is less captured by Cambium. S2G estimates a value factor of 80% in NVEP compared to Cambium's 105%. Over/underestimates in total solar value often also manifest in over/underestimates of the value factor, indicating that the value differences are not just driven by different average price estimates.

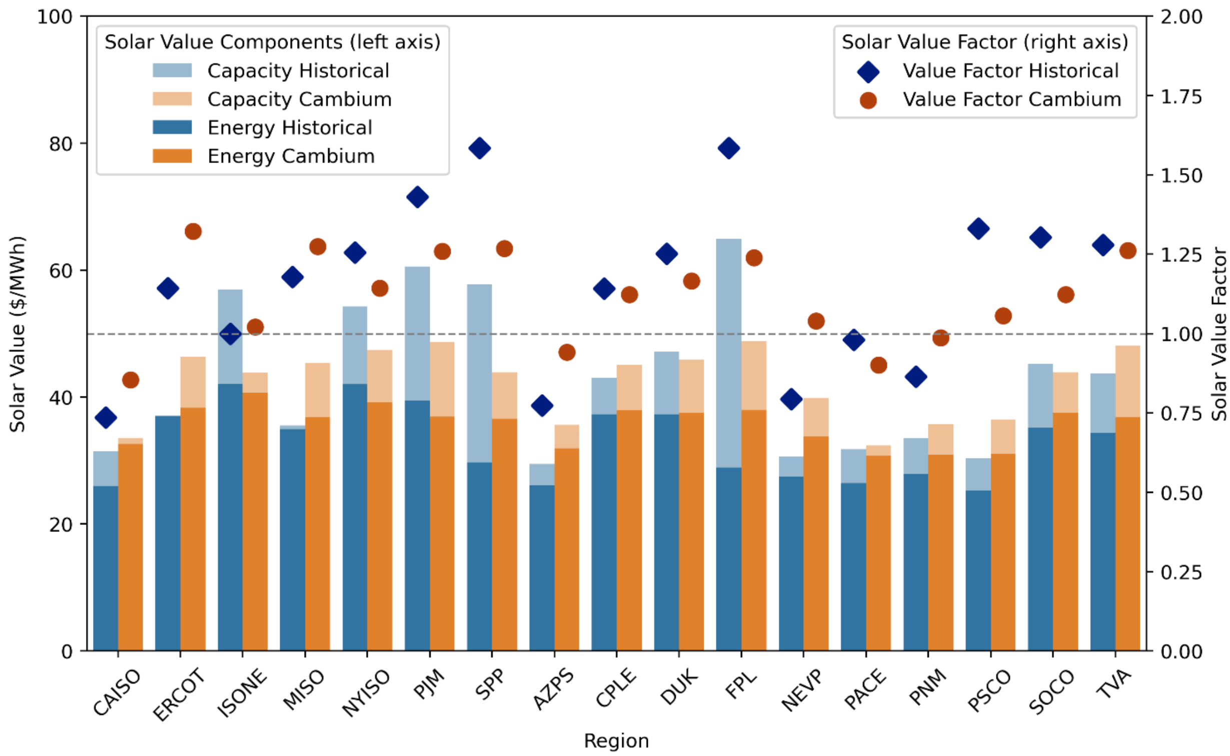


Figure 4-A: Solar Value and Value Factor Estimates by Cambium and Berkeley Lab for 2018

Future solar value is harder to compare because the endogenously determined solar penetration in the Cambium dataset differs from the exogenously stipulated solar penetrations in the LCG data. Cambium's solar penetration rates cluster at a range of 8-13% for NYISO while they exceed LCG's scenarios in CAISO with 30-37% penetration. Nonetheless the estimated solar value decline follows a similar trajectory, especially in NYISO and to some degree in ERCOT (Figure 4-B). Similar to the S2G findings, LCG again projects a stronger value erosion than Cambium at higher penetrations, especially relative to a flat block of power.[9]

[9] In ERCOT LCG estimates $17/MWh or 52% value factor at 20% solar penetration vs. Cambium's $25/MWh or 91% value factor at similar penetration, in CAISO LCG projects 49% compared with Cambium's 52-68%, and in SPP LCG's 42-57% solar value factor is much smaller compared with Cambium's 74-143% at 20-35% solar penetration.

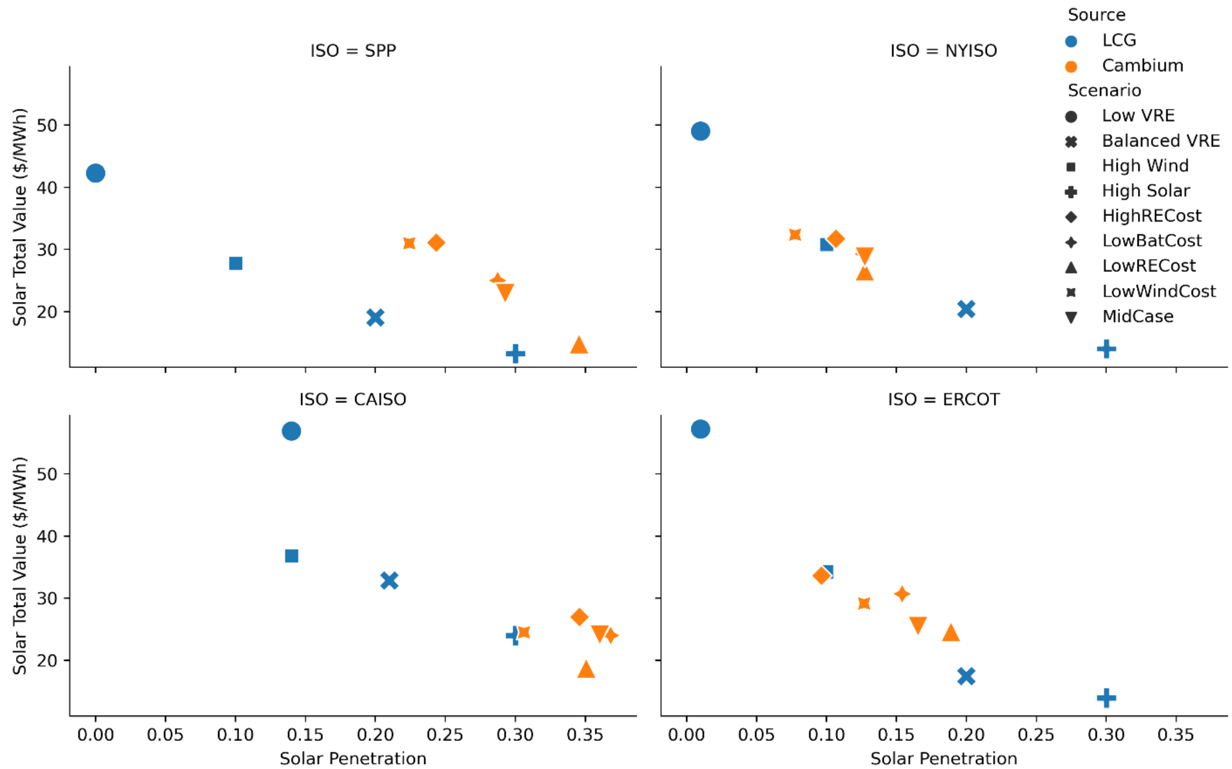


Figure 4-B: Solar Energy and Capacity Value in 2030 for Select ISOs, LCG vs. Cambium

What are the key price dynamics in the analysis that were either replicated or missed by Cambium? Solar value erosion at higher penetrations is driven by a decline in wholesale market prices during the middle of the day when solar generation is greatest. Solar's value factor is further reduced by rising prices in non-solar hours, particularly in the early evening. Cambium captures these diurnal price shifts with increasing solar penetration, though the evening price peaks lessen in later years, presumably due to increased system flexibility and storage.

Are there any novel insights based on using Cambium costs? The comprehensive geographic and temporal scope of Cambium's data allows for new insights. For example, Cambium marginal costs allow for forward-looking estimates of wholesale market revenue at pricing hubs for pure merchant solar and wind projects. The availability of scenarios with low battery cost assumptions in Cambium provides an opportunity to investigate the interaction of storage deployment and solar value. Low-cost storage enables higher solar penetrations than what was otherwise economic (AZPS or PNM) or results in slightly higher values of standalone solar installations (ERCOT, SOCO). Overall the effects of low-cost storage are moderate and do not halt value loss for standalone solar at higher solar penetrations.

4.2 Wind Valuation at Increasing Penetrations

Lead Contact: Jo Seel, jseel@lbl.gov

What was the key insight from the original Berkeley Lab study? Berkeley Lab analyzed wind's historical wholesale energy and capacity value leveraging empirical wind profiles and wholesale price data for 7 ISOs (Wind Technology Market Report or WMTR data, Wiser and Bolinger 2020) and wind's market value in 2030 with LCG data. With both datasets Berkeley Lab found that wind's energy value is larger than the capacity value and that wind's value relative to a flat block of power (value factor) is higher at low penetrations but declines with higher penetration, though at a slower rate than solar's value decline. Wind's combined energy and capacity value in 2019 ranges from $17/MWh (SPP) to $37/MWh (CAISO) depending on region. Wind is less valuable than a flat block in all regions.

How similar are the results from the Cambium costs? Wind values from Cambium consistently exceed the wind value from WTMR in each of the regions (Figure 4-C). Furthermore, overall ranges for wind value in 2018 are tighter for Cambium ($30-42/MWh) than WMTR ($18-45/MWh). Cambium estimates higher energy value of wind in each ISO, particularly in ERCOT, MISO, NYISO, and SPP (where Cambium's estimate is $10-15/MWh higher). Capacity value differences are more mixed: Cambium estimates $5-8/MWh less capacity value in ISONE and SPP, though its estimate is higher than historical values in MISO and NYISO. Wind penetrations are roughly the same in the WMTR and Cambium data, although Cambium underestimated wind in CAISO (3% vs. 7%) and overestimated wind in SPP (35% vs. 24%). Cambium also yields 15%-35% higher wind value factors in all regions. Cambium captures less value erosion in the high penetration regions of ERCOT and SPP. In those regions, Cambium's wind value factor is 87% compared to the WMTR estimate of 55-60%. Other Berkeley Lab analysis using the WTMR dataset indicates that a significant share of the wind value decline is driven by within-region congestion, which may not be as pronounced in Cambium.

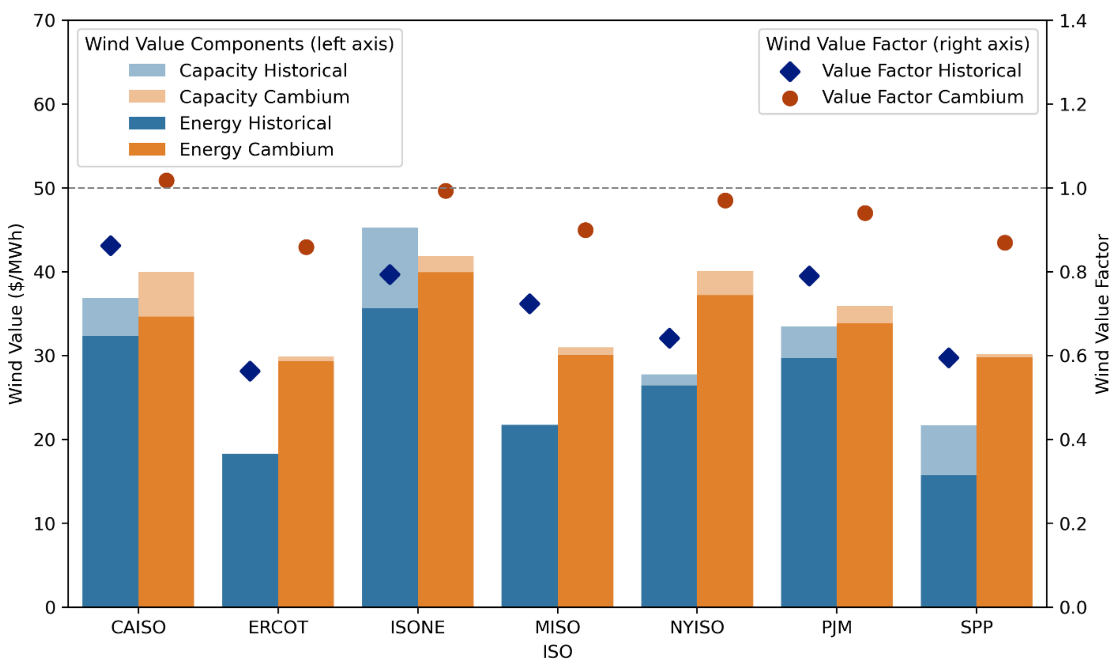


Figure 4-C: Wind Value and Value Factor Estimates by Cambium and Berkeley Lab for 2018

Similar to the solar analysis referenced above, future wind value is harder to compare because the wind penetration shares in the Cambium dataset differs from the exogenously stipulated wind penetrations in the LCG data. Cambium's wind penetration rates cluster at a higher range of 27-32% for NYISO while they fall short of LCG's scenarios in CAISO with 4-8% penetration. Nonetheless the estimated wind value decline follows a similar trajectory, especially in SPP and to some degree in ERCOT (Figure 4-D). In contrast to the empirical WMTR findings, Cambium and LCG project only moderate value erosion at higher penetrations. For example, Cambium's LowCostWind scenario estimates a wind value of $13/MWh or a value factor of 59% at 72% penetration in SPP. This represents a decline in wind value from $27/MWh at 42% penetration in the MidCase, but the wind value factor in the LowCostWind scenario is still higher than the 55% value factor observed empirically in 2019 at a wind penetration of 28%.

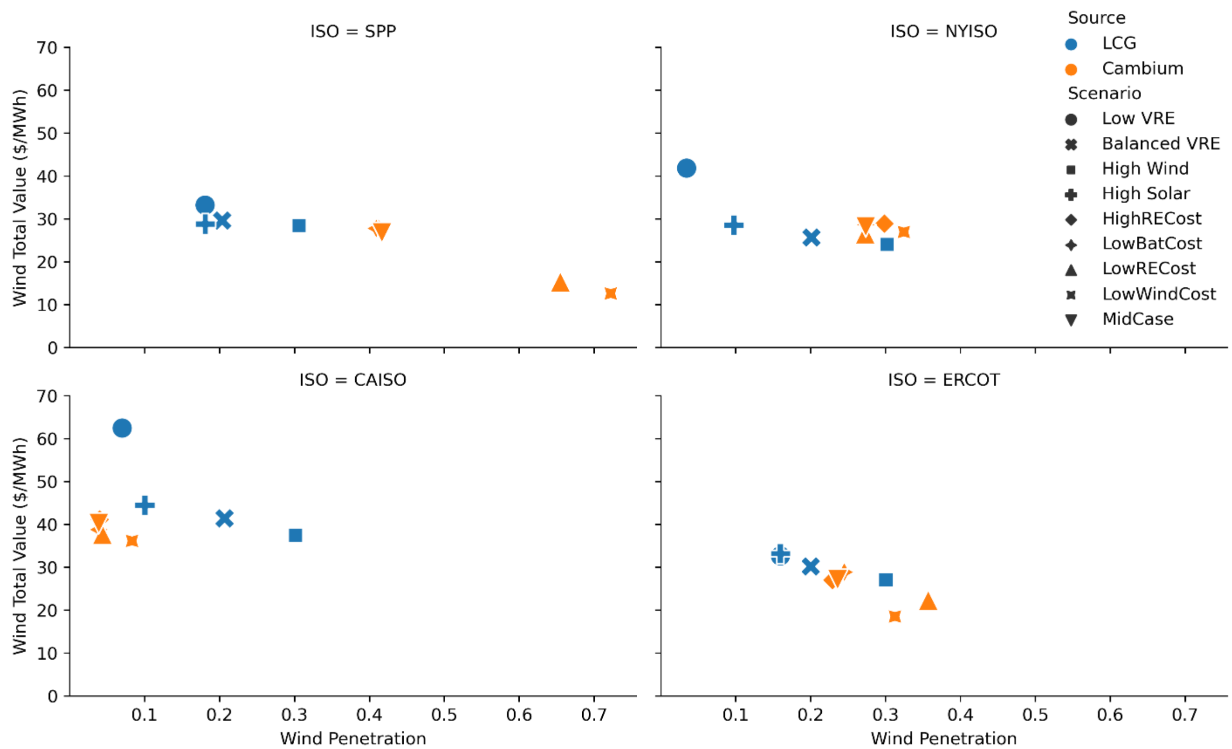


Figure 4-D: Wind Energy and Capacity Value in 2030 for Select ISOs, LCG vs. Cambium

What are the key price dynamics in the analysis that were either replicated or missed by Cambium?
Wind value erosion at higher penetrations is driven by a decline in wholesale market prices when wind generation is greatest and load is low. In the wind belt region of the U.S. this often occurs during the night. While the forward looking scenarios do capture this price shift, Cambium may underestimate the magnitude at which these dynamics are already at play at lower penetrations and the rate of future change. Figure 3-B above shows for example how 2018 spring time prices in SPP are $25/MWh in Cambium but only $10/MWh in historical data. A lack of important constraints in Cambium may lead to higher wind value and value factor estimates.

Are there any novel insights based on using Cambium prices? The comprehensive geographic and temporal scope of Cambium's data allows again for new insights. For example, Cambium prices allow for forward-looking estimates of wholesale market revenue for pure merchant solar and wind projects across many scenarios. Though not investigated here in detail, wind penetrations may exceed 250% of annual local load in later years in the eastern parts of NWPP and Colorado in the LowWindCost scenario. But even under those conditions, wind values remain at $12/MWh, or 50% of the value of a flat block of power.

4.3 Grid Friendly PV: Preparing Solar Plants for High Solar and Energy Storage Futures

Lead Contact: Andrew Mills, admills@lbl.gov

What was the key insight from the original Berkeley Lab study? In this analysis we compared the economic attractiveness of alternative PV plant configurations to a base PV plant in scenarios with differing levels of system-wide PV penetration (Kim et al. 2020). The base PV plant was always a fixed-tilt PV system with a southward orientation. We compared the net value (market value less the levelized cost) of the alternative plant to the net value of the base plant under the same system conditions. Where the net value delta is positive, the alternative configuration is more attractive than the base plant.

At <2% solar penetration, panels with a westward orientation—where output better aligned with high prices in the afternoon—can be marginally more attractive than southward orientation, even when considering the increased levelized cost resulting from lower annual production. At that penetration, west-facing panels can even be more attractive than options that couple solar and storage.

With high solar penetrations already experienced in California (>16%), however, the value of standalone solar, even with west facing panels, decreases. The same shifting wholesale price patterns simultaneously increase the value of adding storage to solar plants. The problem is that storage is expensive. Adding storage to a plant with west-facing panels is particularly expensive on a levelized cost basis because fewer units of energy are available to spread the higher costs. This makes a hybrid with west-facing panels much less attractive, even at high solar penetration. Instead, southward solar+storage plants are more attractive at higher solar penetrations. Because solar investments are long-lasting, and will likely be used at high solar penetration, it makes sense to maximize production rather than sacrifice it with west-ward orientation. This same general finding was found using historical CAISO market prices between ~2-16% solar, and in all four market regions using 2030 LCG prices between the base solar penetration and high solar (30% penetration) case.

How similar are the results from the Cambium costs? We recreated the analysis using 2030 Cambium costs in ERCOT (Figure 4-E).[10] Of the four LCG regions, ERCOT had the biggest 2030 spread of solar penetration levels across Cambium scenarios (~10-20%). The comparable LCG scenarios are the High

[10] We used Cambium prices from p63 to compare to the LCG ERCOT prices.

Wind (10% solar) and Balanced (20% solar) scenario. The narrower penetration range means we would not expect to see as distinct changes in the net value and ranking of alternative options. Analysis with Cambium provides a similar top-line insight: Going from 10% to 20% penetration, the value of hybrids increases relative to the standalone base PV system, such that a hybrid with high solar production is only more attractive than the base PV system at 20% penetration.

		Ranking				Net Value Delta ($/MWh)			
	Source of Wholesale Market Prices	LCG		Cambium		LCG		Cambium	
	Scenario	High Wind	Balanced	HighRECost	LowRECost	High Wind	Balanced	HighRECost	LowRECost
	Solar Penetration	10%	20%	10%	19%	10%	20%	10%	19%
	Base	3	5	2	3	$ -	$ -	$ -	$ -
	1.7 ILR	5	6	3	4	$ (0.5)	$ (0.9)	$ (1.3)	$ (0.9)
	West-Facing	4	7	4	5	$ (0.3)	$ (4.9)	$ (2.8)	$ (1.8)
Standalone	Single Axis Tracking	1	2	1	1	$ 7.3	$ 5.9	$ 4.5	$ 7.5
	Base Hybrid	8	8	8	8	$ (14.8)	$ (6.9)	$ (26.4)	$ (19.0)
	1.7 ILR Hybrid	7	4	7	7	$ (8.7)	$ 0.0	$ (21.4)	$ (13.6)
	West-Facing Hybrid	9	9	9	9	$ (19.6)	$ (13.8)	$ (35.2)	$ (25.3)
	Single Axis Tracking Hybrid	6	3	6	6	$ (5.5)	$ 0.5	$ (17.5)	$ (8.1)
Hybrid	**DC-Coupled 1.7ILR Tracking Hybrid**	2	1	5	2	$ 5.8	$ 10.4	$ (5.0)	$ 1.8

Figure 4-E: Valuation of Alternative PV Plant Configurations, LCG vs. Cambium

For standalone systems, the net value relative to the base PV system is similar whether using Cambium costs or LCG prices. On the other hand, the value boost from storage appears to generally be lower in all of the Cambium cases than the LCG cases. While the hybrid systems increase in attractiveness with growing solar penetration, it is not to the same degree as found with the LCG prices.

What are the key price dynamics in the analysis that were either replicated or missed by Cambium? These results suggest that Cambium costs reflect a similar shift in the timing of high and low marginal costs as found with LCG prices. The Cambium costs, however, do not appear to reflect a similar level of volatility or increase in volatility with increasing solar as found with the LCG prices.

Are there any novel insights based on using Cambium costs? One of the limitations of the Grid-Friendly PV analysis was that it used market value from a single year and levelized costs over the lifetime of the project. Cambium, on the other hand, provides the opportunity to conduct the analysis with both the levelized value and levelized costs. Full life-cycle comparisons of market value and costs are better aligned with developer and utility decisions, even though modeled wholesale prices are unlikely to capture the true volatility of real-world data.

4.4 Geothermal Flexibility Analysis

Lead Contact: Dev Millstein, dmillstein@lbl.gov

What was the key insight from the original Berkeley Lab study? Berkeley Lab analyzed wholesale energy value trends at Geothermal plants in the contiguous United States (Millstein, Dobson, and Jeong 2021). Specifically, we compared the actual value of an always on geothermal plant to the value of a geothermal plant run in a flexible manner. The flexible operation was not meant to exactly mimic operation of current geothermal plants, but to provide guidance as to the value of possible future flexibility enhancements. We tested a number of flexibility strategies, which involved some varying ability to reduce output during the lowest priced hours of each day and enhance output during higher priced hours. We found that in 2017, geothermal plants could have increased their value through more flexible operations by $2–$4/MWh. However, a forward looking analysis, relying on LCG data to simulate high solar and wind scenarios, found that the enhancement to value from flexible operations in 2030 was smaller, at $1/MWh. These calculations took place in CAISO, as most geothermal power plants in the contiguous United States are located in, or near to, California. The decline to the value of flexibility indicates that the modeled future grid put less of a premium on flexible operations, possibly due to the model incorporating little barriers to transmission. Although a future in which flexibility is less valuable than today's market is not impossible, it is not necessarily fated to come to pass.

How similar are the results from the Cambium costs? We ran the same analysis with 2030 Cambium costs. In this case, we find a similar result, shown in Figure 4-F. In both cases, flexibility was more highly valued in a scenario with relatively higher solar penetration (LowRECost versus LowWindCost in Cambium and High Solar versus High Wind in LCG). In both models, flexibility value was close to zero in the case with little wind and solar penetration (HighRECost and Low VRE). This indicates that even under renewable conditions most similar to today's levels, the value of flexibility is found to be lower with Cambium and LCG prices, relative to the value with historical prices.

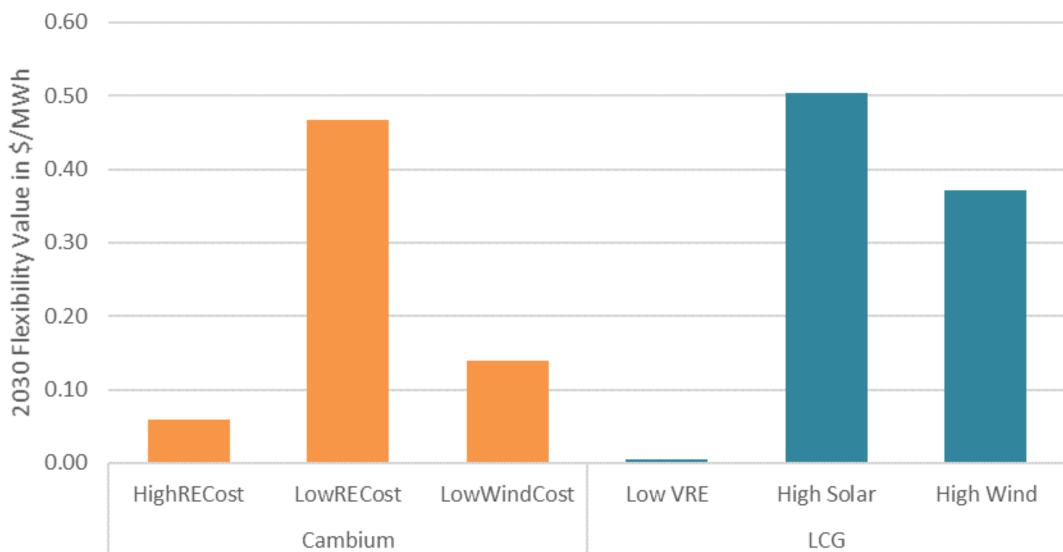


Figure 4-F: The Value of Geothermal Flexibility, LC vs. Cambium

What are the key price dynamics in the analysis that were either replicated or missed by Cambium? It is hard to know what to conclude from the lower value of flexibility. It either suggests that the grid may evolve in a manner in which flexibility is less valuable, or it suggests that both LCG and Cambium unrealistically limit price fluctuations. For example, the Cambium marginal cost series has only 57 hours in 2030 with prices above $100/MWh and did not allow for negative prices. In contrast, in 2019, CAISO prices at a hub (TH_SP15_GEN_APND) had 165 hours above $100/MWh, and 137 prices below negative $1/MWh.

4.5 High VRE Impact on Large Energy Consumers: Hydrogen

Lead Contact: Jo Seel, jseel@lbl.gov

What was the key insight from the original Berkeley Lab study? The Berkeley Lab found that high penetrations of VRE may make investments in new goods produced with electricity economical. The analysis reached this conclusion by calculating hydrogen production costs via electrolysis under different scenarios of VRE penetration. One key finding from this analysis was that due to the increased frequency of low prices in high VRE scenarios, operators of electrolyzers may minimize hydrogen production costs at low annual utilization rates (25-70%) rather than operating for nearly all hours of the year. Operating the electrolyzer flexibly for shorter durations decreases operating costs per unit of hydrogen while increasing per unit capital costs.

How similar are the results from the Cambium costs? We find that the key conclusions from the LCG data are replicated using Cambium costs. Namely, total levelized hydrogen production costs are similar, reaffirming the conclusion that new investments in goods produced with electricity can be promising in a high VRE future. Cambium costs also show that producers of hydrogen may prefer to flexibly operate for short durations of the year when faced with more frequent periods of low prices. Figure 4-G compares levelized production costs from the Cambium cost data (leftmost bars) with LCG data (rightmost bars). In ERCOT, the results are strikingly similar with levelized production costs between $1.50-$2.25 per kg and utilization rates between 50% and 80% of all hours of the year. Likewise, in CAISO levelized production costs decrease for the higher VRE penetration scenarios. One notable difference is that in CAISO a utilization rate as low as 25% was cost-optimal in the high solar scenario with the LCG data compared to only 54% with the Cambium data. The lowest utilization rate found using the Cambium price series was 40% in SPP in the LowRECost scenario.

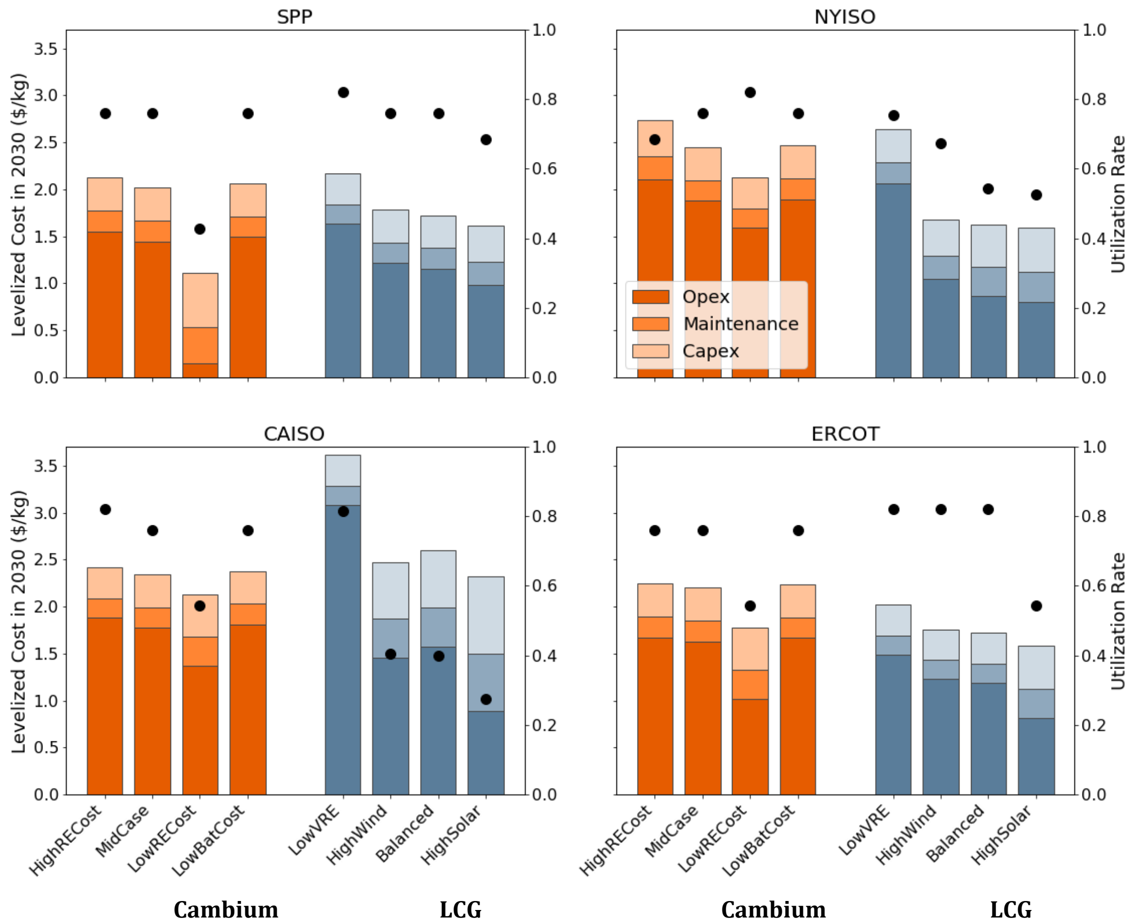


Figure 4-G: Levelized Production Cost of Hydrogen and Utilization Rate, LCG vs. Cambium

What are the key price dynamics in the analysis that were either replicated or missed by Cambium? While the overall results using both cost series are similar, the lower cost variability and lower frequency of near-zero electricity costs in Cambium prices cause utilization rates to not dip as low as they do when using LCG prices. The lower cost volatility in Cambium costs causes the composition of overall production costs to not shift as heavily toward capital costs as depicted by the shading of each bar in Figure 4-G. In CAISO, capital costs make up a large share of overall cost when the utilization rate is 25% using LCG prices, but the same effect is not seen using Cambium costs. While the share of capital costs is lower in Cambium costs across most scenarios, SPP is a notable exception where capital costs constitute more than 48% of total cost when VRE penetration exceeds 100%.

Are there any novel insights based on using Cambium costs? One benefit of using Cambium costs is that the low renewable cost scenario in SPP has VRE penetration levels in excess of 100% of load, which produces attractive economics for electrolysis. The LCG price series does not analyze such high levels of VRE penetration and does not find as low of a cost of hydrogen. Finally, we again find it surprising that Cambium's low battery cost scenario does not produce markedly different results than the other scenarios.

4.6 High VRE Impact on Retail Rates

Lead Contact: Jo Seel, jseel@lbl.gov

What was the key insight from the original Berkeley Lab study? The Berkeley Lab analysis of rate design under high VRE penetrations had two main findings. First, time-differentiated rate structures are more effective at reducing deadweight loss[11] (DWL) at high VRE penetrations, while "flat" structures that dominate retail pricing regimes today produce much higher levels of DWL as VRE penetration increases. Second, the characteristics and abilities of time-differentiated rate structures to reduce deadweight loss depend not only on the amount of VRE penetration but also the type of VRE penetration. Time-differentiated rate structures are more economically efficient in solar dominated systems than in wind dominated ones due to the more regular diurnal price patterns with high solar. Characteristics of time-differentiated rate structures are sensitive to the relative shares of wind and solar, too, such as the peak-to-off peak price ratio[12] and the timing of the peak period.

How similar are the results from the Cambium costs? Cambium costs produce results that are consistent with the LCG data. Cambium provides two scenarios in SPP that feature VRE penetrations in excess of 100%. The associated peak-to-off peak price ratios are on average double that of the three lower VRE penetration scenarios (3.1:1 vs. 1.6:1). Implementing a two-period time-of-use rate eliminates nearly 70% of the DWL associated with a flat rate in the high wind penetration scenario compared to only 30-35% in the three scenarios featuring lower VRE penetration. The difference was not as stark with the LCG data. A two-period Time-of-Use (TOU) rate in the high wind scenario reduced 61% of the flat rate's DWL and reduced 57% in the low VRE penetration scenario. This smaller difference with LCG data could be caused by the overall lower VRE penetrations in the LCG data. Figure 4-H shows how the characteristics of time-differentiated rate structures can vary based on the type of VRE penetration. Looking closer at SPP, the figure shows that the HighRECost and the LowRECost scenarios feature markedly different diurnal price curves during the summer months, largely due to a 25% difference in wind penetration. This is also apparent in ERCOT where the LowRECost scenario features 12% more wind penetration. In CAISO, wind and solar generation shares are nearly identical in both scenarios, and the only significant change in rate characteristics is a larger peak-to-off peak price ratio due to higher costs from the high renewable cost scenario.

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[11] In economics, DWL represents the lost economic value to society caused by a market failure. In the case of retail electricity pricing, rates often do not reflect marginal cost because the utility business is a natural monopoly and marginal costs can vary substantially from rates on an hour-to-hour basis.

[12] The peak-to-off peak price ratio is calculated by taking the on-peak rate and dividing it by the off-peak rate. For example, if the on-peak rate is $0.20/kWh and the off-peak rate is $0.10/kWh, then the peak-to-off peak price ratio would be 2:1.

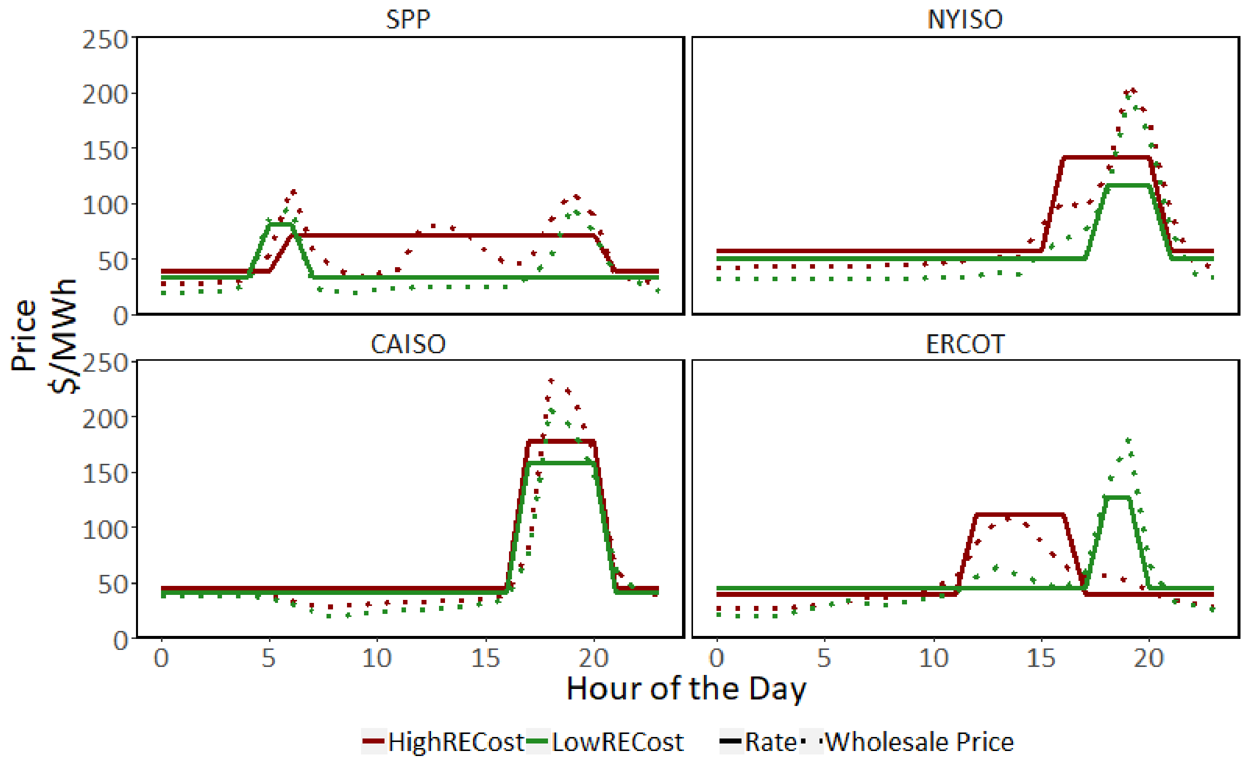

Figure 4-H: Two-Period TOU Rate during Summer Months for Low and High RE Cost Scenarios

The Cambium data also confirms that the type of VRE generation matters in choosing the appropriate complexity of time-differentiated rates. Adding a third period can offer significant efficiency gains in CAISO during the low-demand winter months in California, where solar reduces midday prices. In contrast, the more wind-dominated system in NYISO offers less efficiency gains. We arrived at the same conclusion using the LCG data.

What are the key price dynamics in the analysis that were either replicated or missed by Cambium? The average DWL per MWh is higher when evaluating rate designs with Cambium prices. Relatedly a three-period TOU combined with a critical peak pricing program produces an average of $2.1/MWh of DWL using the Cambium data but only $0.3/MWh of DWL with the LCG data. The likely cause of this higher DWL is the greater volatility of total end-user prices in the Cambium dataset, driven primarily by the allocation of capacity prices over the top 40 net-load hours instead of the 100 net-load hours in the LCG data (Cambium's standard deviation in CAISO is $115/MWh vs. $70/MWh in LCG; in NYISO and SPP $85-$95/MWh vs. $55-$80/MWh). The stronger end-user cost volatility makes it more difficult for time-based rate structures to consistently mirror the diurnal marginal cost curve.

Are there any novel insights based on using Cambium costs? A novel contribution of Cambium costs is the very high level of VRE penetration in excess of 100% of load in the LowRECost and LowWindCost scenarios in SPP. The DWL of a flat rate in these scenarios is approximately $11/MWh, or 40% of the $28/MWh flat rate, stressing that reliance on simple rates in futures with high VRE penetrations is increasingly costly. Cambium's LowBatCost scenario also provides a unique opportunity to study rate design with more storage deployment, but the underlying diurnal price curves associated with this scenario are puzzling as peak prices are higher in the LowBatCost than in the LowWindCost scenario in three of the four ISOs. Only in CAISO do lower battery costs produce lower peak prices. Finally, Cambium marginal cost include "policy costs" (e.g., renewable portfolio standards) and distribution losses that more accurately reflect the cost of providing electricity to end-users. Cambium's inclusion of these additional cost components makes it a better fit for studying rate design than LCG prices which only include energy and capacity costs, although the latter feature added carbon penalties.

4.7 High VRE Impact on Energy Efficiency Portfolios

Lead Contact: Jo Seel, jseel@lbl.gov

What was the key insight from the original Berkeley Lab study? Berkeley Lab investigated how the time-sensitive energy and capacity value of seven EE measures in eight climate zones could change with increasing VRE penetrations. Using LCG data for 2030, we found that individual measures exhibit varying sensitivity to value changes, but the overall value of EE measures decreases for most of them, driven by a strong decline in their energy value. The magnitude of value change depends on the type of VRE additions, with high solar futures causing greater EE value loss than wind additions. In high solar futures residential lighting EE improvements that address evening loads rise in relative value, while commercial HVAC and lighting measures that reduce load during the middle of the day lose attractiveness. An EE program designer will thus want to perform scenario-dependent forward-looking resource plans and adjust the EE portfolio based on local net-load and pricing patterns.

How similar are the results from the Cambium costs? Repeating the analysis with Cambium costs yields largely similar conclusions. EE measures lose value with increasing VRE penetration relative to the MidCase and HighRECost scenarios. Similar to our findings with LCG prices, greater solar penetration (LowRECost) affects the value more than higher wind penetration (LowWindCost), with the exception of some measures in SPP's 70% wind penetration scenario. The overall magnitude of value reductions seem smaller with the Cambium data ($5-15/MWh) relative to the LCG data ($10-$25/MWh). Measure rankings across scenarios are more stable with Cambium costs as shown in Figure 4-I. This is because Cambium scenarios feature more wind and solar even in the lower penetration scenarios, thereby reducing the marginal value erosion effect. Commercial HVAC measures tend to perform better in Cambium's high wind scenarios compared to LCG's.

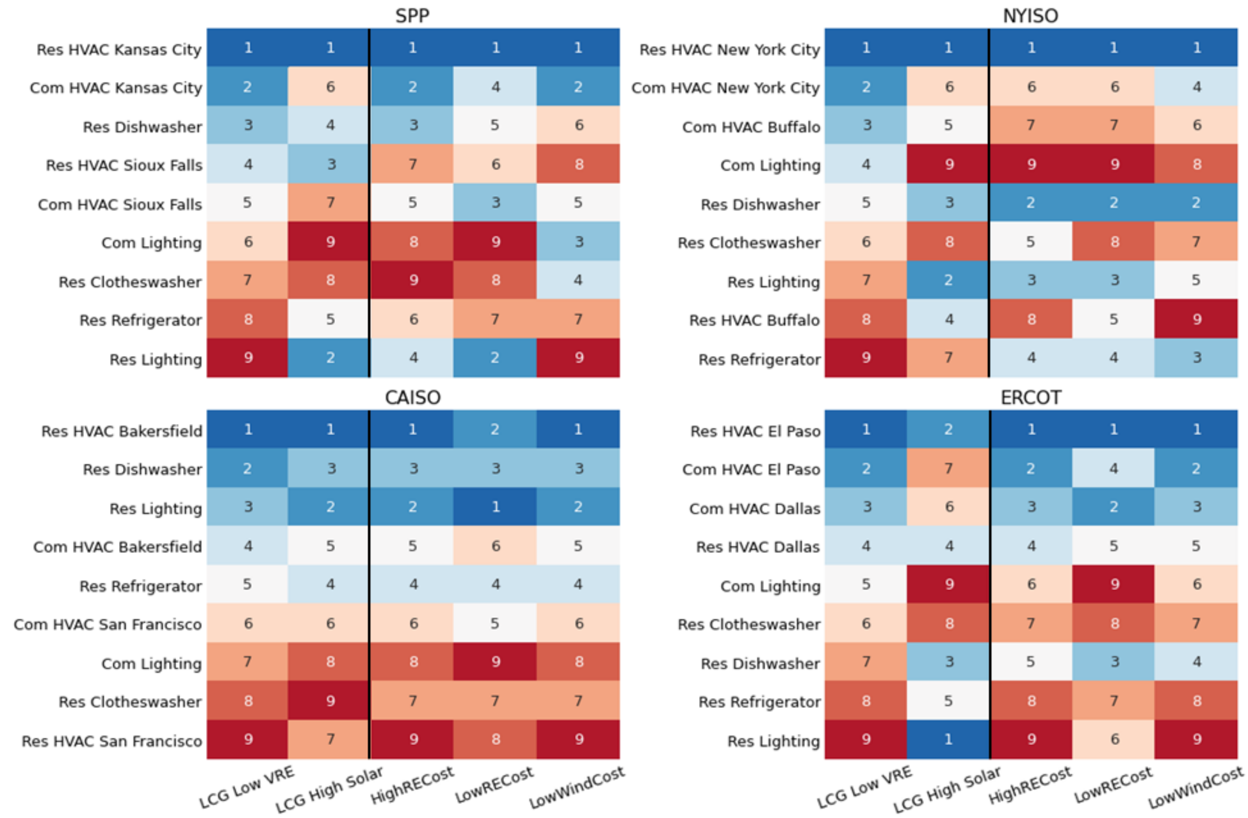

Figure 4-I: Ranking of Select Energy Efficiency Measures by Total Value, LCG vs. Cambium

What are the key price dynamics in the analysis that were either replicated or missed by Cambium? Value changes of EE measures are primarily driven by changes in diurnal price profiles and alignment of load saving shapes with high net-load hours.[13] As discussed above in section 3, Cambium prices show more moderated diurnal marginal cost profiles in comparison with the LCG data, leading to less value variability across measures. Relatedly, Cambium does not model ORDC-driven price spikes in ERCOT, which aligned well with residential lighting savings in the LCG data, leading to a less prominent ranking there.

Are there any novel insights based on using Cambium costs? The comprehensive geographic scope with fairly refined cost estimates of the Cambium data could facilitate a deeper analysis of relative performance of EE measures across climate zones in the U.S. Having access to multi-year projections of power system evolution pathways also enables more sophisticated performance assessments over the course of an EE measure's lifetime relative to a simple snapshot in time.

[13] This assumes constant reductions of the load shape, which was also the assumption in the Berkeley Lab analysis with LCG data.

4.8 Representation of DERs in Utility Integrated Resource Planning

Lead Contact: Sydney Forrester, spforrester@lbl.gov

What was the key insight from the original Berkeley Lab study? Berkeley Lab provided technical assistance to Indiana regulators on improving the representation of EE and other distributed energy resources in utility IRP. To support the analysis, each investor-owned utility (IOU) provided modeled hourly energy production costs and EE hourly resource shapes. Berkeley Lab used the data to quantify the marginal value of EE measures taking into account its time-dependent value. Value was primarily driven by the coincidence between the specific end use availability (i.e., periods of high EE savings) with midday summer peaks and/or dual morning and evening winter peaks (i.e., periods of high marginal costs). Seasonally-specific measures such as residential HVAC, with very high summer and fall value, did not rank as high on an annual basis as measures that saved energy both in summer and winter (e.g., lighting, envelope, appliances) (See Figure 4-J left panel). Five of the 13 measures had maximum average seasonal value in the winter while eight were in the summer.

How similar are the results from the Cambium costs? The Cambium data resulted in a higher marginal value of EE across all measures and a higher summer seasonal value relative to winter seasonal value (Figure 4-J).[14] This led to only one EE measure with winter as its season of highest value when using Cambium marginal energy costs compared to five measures using Indiana IOU production costs. Using Cambium data, therefore, caused the annual average value of EE measures providing high winter value to fall in rank, replaced by measures providing higher summer value (e.g., residential envelope vs. residential HVAC).

Indiana Utility IRP Values, 2020

Measure	Max Seasonal Avg. Marginal Value [$/MWh]*	Avg. Annual Marginal Value [$/MWh]	Rank by Marginal Value				
			Year	Fall	Winter	Spring	Summer
C&I Appliance	$ 33.20	$ 31.94	1	1	1	1	1
Resi Envelope	$ 32.00	$ 30.86	2	3	2	2	3
Resi Appliance	$ 31.93	$ 30.48	3	4	3	5	4
C&I Refrigeration	$ 31.83	$ 30.01	4	5	4	3	6
C&I Lighting	$ 31.05	$ 29.61	5	6	6	4	5
Resi HVAC	$ 32.72	$ 29.57	6	2	9	7	2
C&I Electronics	$ 31.18	$ 29.07	7	10	5	6	10
C&I Envelope	$ 29.85	$ 28.46	8	7	N/A	9	8
Resi PoolPump	$ 29.59	$ 28.36	9	8	N/A	11	9
Resi Other	$ 30.53	$ 28.33	10	9	8	8	7
Resi Lighting	$ 29.02	$ 27.78	11	11	7	10	13
C&I Other	$ 28.24	$ 26.51	12	13	10	12	11
C&I HVAC	$ 28.19	$ 26.21	13	12	11	13	12

* Blue indicates higher seasonal value for the winter, orange for the summer

Cambium Mid-Case Busbar Energy Values, 2020

Measure	Max Seasonal Avg. Marginal Value [$/MWh]*	Avg. Annual Marginal Value [$/MWh]	Rank by Marginal Value				
			Year	Fall	Winter	Spring	Summer
Resi HVAC	$ 35.02	32.34	1	1	9	2	1
C&I Appliance	$ 33.61	32.20	2	2	2	1	2
C&I Lighting	$ 33.35	31.84	3	3	4	4	3
Resi Lighting	$ 33.01	31.66	4	12	1	5	13
Resi Other	$ 32.55	31.64	5	5	3	3	4
Resi Envelope	$ 32.51	31.49	6	4	6	12	5
Resi Appliance	$ 32.50	31.25	7	7	7	10	6
C&I HVAC	$ 32.22	31.24	8	8	10	6	8
C&I Other	$ 32.49	31.21	9	8	8	11	9
C&I Refrigeration	$ 32.04	31.15	10	9	5	7	9
C&I Envelope	$ 31.42	30.97	11	10	N/A	8	10
Resi PoolPump	$ 31.24	30.87	12	11	N/A	11	11
C&I Electronics	$ 31.21	30.55	13	13	11	13	12

* Blue indicates higher seasonal value for the winter, orange for the summer

Note: Changes in annual average value rankings are indicated by arrows and red (lower ranking)/green (higher) color scheme.

Figure 4-J: EE Measures' Marginal Value and Ranking by Season in 2020, Indiana IRP vs. Cambium

[14] We compared the results using IOU IRP production costs to the results using Cambium Mid-case scenario's busbar energy costs. For the Cambium data comparison, we focused on 2020 (and, to a lesser extent, 2030), which corresponds to the same year as the IOU IRPs' production cost data. We also used balancing areas in Cambium that aligned with each Indiana IOU's service territory. In instances where a territory spanned two Cambium BAs, we took the load-weighted cost averages for each hour.

What are the key price dynamics in the analysis that were either replicated or missed by Cambium? Cambium energy prices exhibit seasonal and hourly patterns that roughly mimic those modeled by the IOUs, both in 2020 and 2030 (e.g., IOU and Cambium energy marginal cost tend to peak in the same hour or close to the same hour), Figure 4-K. In 2020, Cambium costs are higher than IOU prices and are lower in 2030. In the case of our analysis, the *difference* between Cambium costs and IRP prices had the largest impact on EE marginal value rankings. For example, Cambium's summer costs were consistently higher across all hours, increasing EE value evenly for all measures. On the other hand, spring and winter saw higher Cambium costs only from the late afternoon until early morning, which would have lowered the value and ranking of an EE measure that provided morning peak savings relative to other times in the year (e.g., residential envelope).

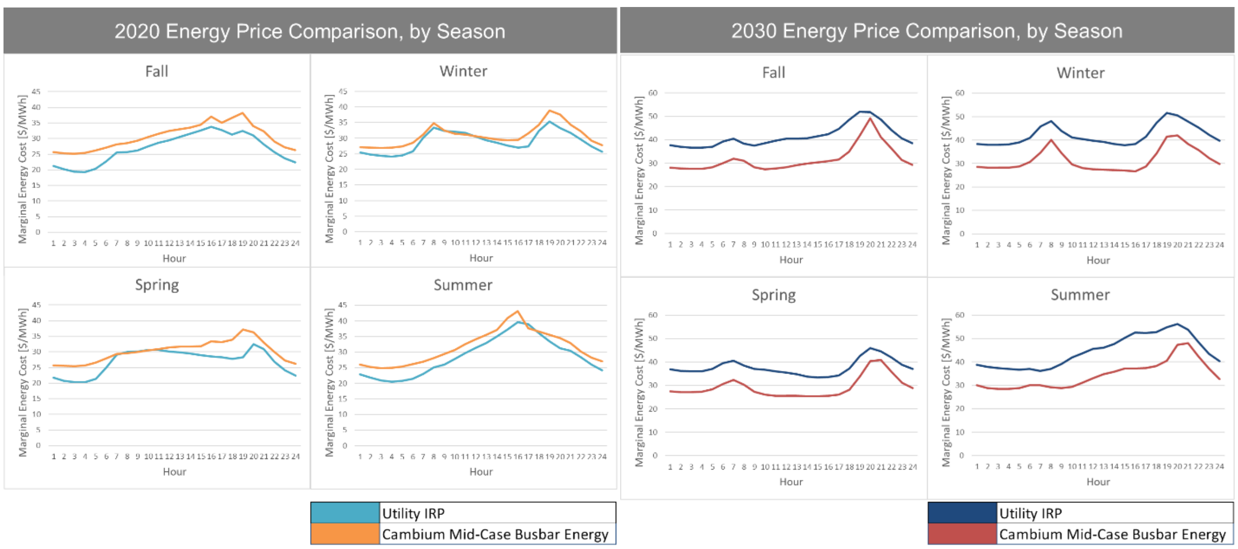

Figure 4-K: Average Seasonal Energy Prices for 2020 and 2030, IOU IRP vs Cambium (MidCase busbar)

Are there any novel insights based on using Cambium costs? Separate from the comparison between IOU IRP modeled prices and Cambium, we compared future Cambium scenarios and their general impacts on EE marginal value. Specifically, we found that residential EE measures' value increased using the 2030 LowRECost scenario (relative to the MidCase scenario) due to the shift of midday value to evenings during the summer months, coincident with many residential EE savings shapes. This suggests important implications for the design of EE programs and the possible increased emphasis of residential EE measures in a future scenario of higher renewable energy.

5. Suitability of Cambium Costs in Ongoing Berkeley Lab Studies

The purpose of this section is to evaluate the suitability of Cambium marginal costs in currently-funded Berkeley Lab studies. In contrast to the previous section, these studies have not yet used wholesale prices in their analysis, making a direct comparison to outcomes using Cambium data impossible. We explore the suitability of Cambium costs though a high-level summary of the needs and objectives of each project. For each of the studies in this section, we summarize the goal of the analysis, the role of wholesale prices in the analysis, key characteristics of wholesale prices needed to conduct the analysis, and the suitability of Cambium costs for each project.

5.1 Time-sensitive Value of Efficiency Calculator

Lead Contact: Natalie Mims Frick, nfrick@lbl.gov

Project description and goal: Berkeley Lab is developing a Time-sensitive Value of Energy Efficiency (TSV-EE) Calculator (Calculator) that will estimate the value of energy efficiency measures using hourly electricity system cost estimates for five value streams. In addition, it estimates the value of electricity system risk mitigation on an annual basis as a percent adder to the annual monetary savings of the five hourly value streams for each year in the study horizon. The Calculator is a publicly available, free tool that can be used to quickly estimate the value of energy efficiency measures on an hourly basis using default or user-defined inputs. Use cases include cost-benefit analysis, electricity resource planning, distribution system planning, and efficiency program design.

Role of wholesale prices in the analysis: The Calculator contains default system load shapes, system costs and end use load profiles by balancing area to allow users that otherwise lack data access to estimate the value of efficiency. Cambium data is the source for the default system load shapes and costs for electric energy and generation/transmission capacity. Cambium hourly carbon emissions are also used as inputs to an intermediate calculation that monetizes marginal emissions for carbon mitigation purposes. Finally, Cambium's hourly allocation for generation/transmission capacity costs are used to inform the allocation of avoided distribution system capacity cost.

Key characteristics of wholesale prices: Currently, the Calculator uses all marginal costs for all years in the MidCase scenario for balancing area p33. In the future we hope to create a Calculator for each state leveraging reported prices for all years in the MidCase scenario. Ideally, Cambium's geographic resolution would match the service territory of the utilities that would employ the Calculator, but the current balancing area granularity is good enough to represent most large utilities.

Suitability of Cambium costs for the project: One of the goals of the Calculator is to provide users, regardless of location or access to electricity data, the ability to estimate the value of efficiency. There is not another publicly available dataset that provides hourly wholesale marginal cost estimates for the lower 48 states, so Cambium is the most suitable dataset available. In absence of the Cambium data we likely would have only been able to provide the Calculator to regions of the country with easy access to publicly available utility avoided costs. One challenge with the Cambium dataset is that generation and transmission capacity costs are combined. The Calculator allows the user to provide their own data or use default data that we chose to keep generation and transmission value streams separate.

5.2 Time-sensitive Efficiency and Flexibility Valuation in the Scout Model

Lead Contact: Jared Langevin, jared.langevin@lbl.gov
Goal of the analysis: The Scout analysis engine (scout.energy.gov) enables time-sensitive valuation of the impacts of energy efficiency and flexibility measures on consumer energy costs and CO2 emissions.

Role of wholesale prices in the analysis: Scout uses hourly Cambium data to reattribute projections of average residential and commercial retail electricity prices and annual CO2 emissions on an hourly basis. Wholesale hourly cost data from Cambium (energy, capacity, ancillary services, and policy costs) are used to develop regional hourly electricity cost intensities that are used to adjust the average retail electricity price in a given projection year up or down. The hourly variation in electricity costs reflects the time-varying value of building load reductions or increases at a particular point in time and for a particular location.

Key characteristics of wholesale prices needed to conduct the analysis: Scout analyses of sub-annual load impacts from efficiency and flexibility are conducted for the 25 Electricity Market Module (EMM) regions in the 2020 Energy Information Administration (EIA) Annual Energy Outlook (AEO). Annual baseline projections of loads, prices, and emissions follow the AEO Reference Case from 2016-2050. Our use of Cambium data is currently limited to the MidCase scenario, which is the closest in electricity generation mix to the AEO Reference Case. To match Scout's geographical breakout, we translate Cambium data from the 134 ReEDS balancing areas to the 25 EMM regions using a county-level, population-weighted mapping. Cambium data are also only available for every two projection years in our time horizon, beginning in 2018 (e.g., 2018, 2020, 2022, etc.); we carry forward the hourly price intensities for the intervening years. Finally, the calendar year assumed by the Cambium data is a non-leap year that starts on a Sunday, which is consistent with the assumptions used in Scout to develop hourly load baselines and savings shapes that are applied to the Cambium-based cost and emissions shapes.

Suitability of Cambium costs for this particular project: While some manipulation of the Cambium data is required for use in Scout calculations as described above, we find the Cambium data to be highly suitable for our overall analysis objectives. Moreover, we are not aware of other similar openly available and regularly updated analysis products that would fill this particular type of analysis need for Scout. For example, while we normally rely on EIA datasets to establish baseline conditions for Scout analyses, these data are not generated with the hourly temporal resolution that is needed to assess the time-sensitive value of building efficiency and flexibility to the electric grid.

5.3 Grid-interactive Efficient Buildings Roadmap analysis

Lead Contact: Andrew Satchwell, asatchwell@lbl.gov

Goal of the analysis: Berkeley Lab and The Brattle Group quantified the power system benefits of grid-interactive efficient buildings (GEBs) to support the Building Technologies Office (BTO) GEB Roadmap (DOE, 2021). The analysis found between $8 billion and $18 billion of GEB benefits annually by 2030, or two to six percent of total U.S. electricity generation and transmission costs projected by the EIA in 2030 (see Figure 5-A). The cumulative power system benefits from 2021 to 2040 ranged from $100 billion to $200 billion depending on assumptions about customer adoption, capacity costs, and renewable energy deployment. These financial savings were accompanied by significant environmental benefits, with annual CO_2 emissions reductions reaching 80 million tons (i.e., about 6 percent of total power sector emissions) by 2030.

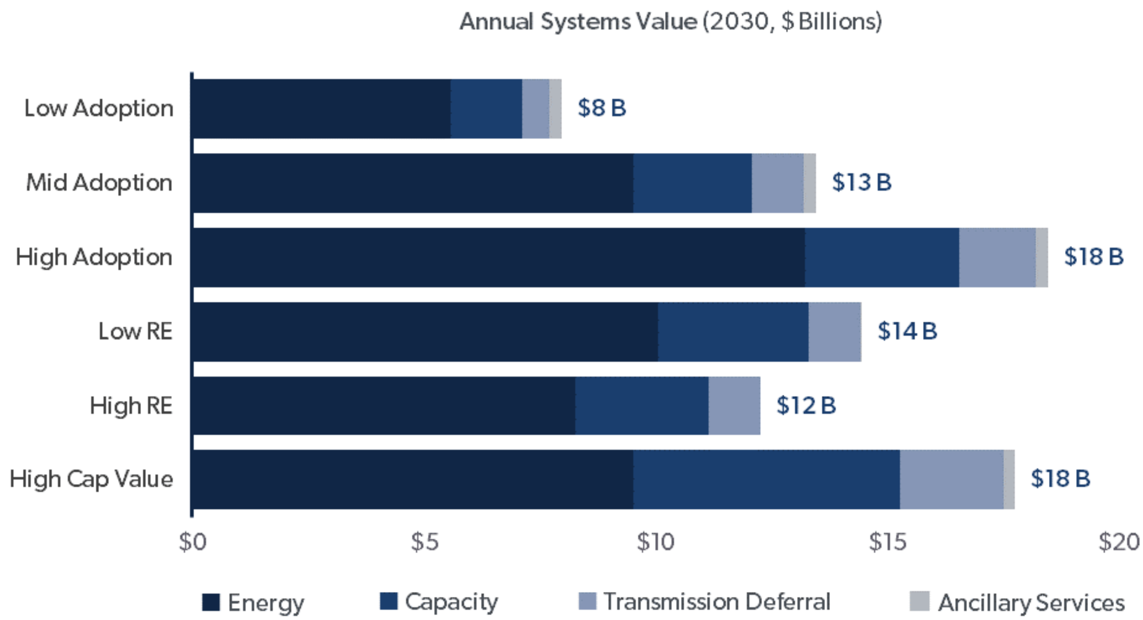

Figure 5-A: The U.S. Power System Value of GEBs Due to Achievable Levels of GEB Adoption

Role of wholesale prices in the analysis: Cambium marginal capacity, energy, and ancillary services costs, and short-run emissions were used to quantify power system benefits. Transmission capacity benefits were separately estimated using values from a literature review. A portfolio of technically achievable EE and demand flexibility measures and technologies was derived using Berkeley Lab and NREL building simulation modeling tools (i.e., ResStock and Scout). Importantly, the EE and flexibility measures were characterized by hourly savings in representative weather locations for 22 U.S. regions. Cambium marginal costs and emissions were then multiplied by the hourly savings to derive total GEB benefits for each region.

Key characteristics of wholesale prices needed to conduct the analysis: The analysis used 2030 and 2040 marginal capacity, energy, and ancillary services costs, and short-run emissions from the 2020 MidCase, HighRECost, and LowRECost Standard Scenarios. A single representative balancing authority was chosen for each of the 22 U.S. regions based on having an hourly energy cost shape that was most representative of all BAs in the region. Other assumptions, including weighting and scaling factors, were used to adjust Cambium and other data sources.

Suitability of Cambium costs for this particular project: Cambium was selected because it was publicly available, allowed the use of a DOE-funded dataset for a DOE office roadmap, and had sufficient geographic coverage for all scenarios of interest. Importantly, the Cambium hourly costs and emissions ensured the analysis captured the time-dependent value of GEBs.

5.4 California Demand Response Potential Study

Lead Contact: Brian Gerke, bfgerke@lbl.gov
Goal of the analysis: The California Demand Response Potential Study is an ongoing project funded by the California Public Utilities Commission (CPUC) to project the future quantity, cost, and value of the DR resource in the electricity service territories regulated by the CPUC. The study rests on a Berkeley Lab modeling framework called DR-Path. DR-Path builds a bottom-up picture of the future DR resource, starting from individual customer loads. It then estimates DR flexibility under different technology scenarios and aggregates the result up to estimate the system-level DR resource at different procurement costs.

Potential role of Cambium outputs in the analysis: An important component of the cost modeling in DR-Path is the estimation of wholesale market revenue that could be captured by a market-integrated DR resource. A realistic estimate of this value requires a forecast of wholesale market prices under different system load conditions, in the context of forecasted future generation assets, which Cambium provides.
In addition, the next phase of the DR Potential Study will consider the size of the DR resource that could be enabled through customer response to real-time pricing, which also requires a time-series forecast of wholesale market prices, such as Cambium produces. It would also be desirable in the next phase to estimate the marginal avoided emissions of load-shedding or load-shifting DR, which could be estimated with a time-series forecast of grid emissions intensity, such as Cambium's.
A hurdle that must be overcome before using Cambium data in the DR Potential study is a mismatch between the underlying load models in the two studies. The DR Potential Study is based on actual customer load data aggregated up to the system level and projected to future years. As such, it is based on specific weather data that will necessarily differ from what is used in the Cambium modeling, with the result that peak load periods will not align between the two studies. It may be possible to overcome this by using the Cambium data to build a predictive model of price and emissions as a function of system net load, or by shuffling the Cambium data to match days with similar system load conditions between the two load models.

Key characteristics of Cambium outputs needed to conduct the analysis: The integration of Cambium data envisioned here would make use of the time-series forecasts of CAISO wholesale prices and emissions intensity produced by Cambium. Also helpful would be any other ancillary data products, or input assumptions, that may be important for building a predictive model of price and emissions based on net load (e.g. assumptions about natural gas prices may be an important variable in building a model of price as a function of net load).

Suitability of Cambium outputs for this project: CPUC already produces a time-series forecast of wholesale prices and emissions in its Avoided Cost Calculator (ACC) tool, which is used to assess cost-effectiveness of future energy efficiency and DR programs. LBNL has access to the load data underlying this tool and is in the early stages of integrating its forecasts into the DR-Path model. From the perspective of the DR Potential Study, the Cambium data provide similar forecasts. Because the DR Potential Study is intended to inform future DR program development for the CPUC, the ACC will need to remain the default source of price and emissions estimates for DR-Path. However, the ACC represents only a single future scenario for the CAISO power system. Integration of Cambium data should be achievable using the same framework being used to include the ACC estimates. To the extent that Cambium represents a realistic and reliable forecast of CAISO prices and emissions, it would allow exploration of a broader set of scenarios, and comparison to the ACC results would provide a better overall understanding of forecast uncertainty in the model.

5.5 Connected Communities Pilot Evaluation Effort

Lead Contact: Pete Cappers, pacappers@lbl.gov
DOE announced a funding opportunity for pilots to demonstrate the ability of groups of buildings and DERs to provide cost-effective grid services through demand flexibility and efficiency. These pilots must maximize use of renewable resources and reduce emissions, while maintaining (if not enhancing) occupant satisfaction and productivity. Berkeley Lab supports DOE in this Connected Communities FOA by evaluating the impacts of the various selected pilots. DOE wants to forecast the aggregate benefits if these pilots were rolled out more broadly based on the experience of each pilot in providing various grid services. The Cambium data set could be used by the evaluation team to value the energy, capacity, and ancillary services being provided by large portfolios of geographically distinct connected communities in the future.

5.6 Multi-Distributed Energy Resources Rate Impacts Analysis

Lead Contact: Andrew Satchwell, asatchwell@lbl.gov
Goal of the analysis: Berkeley Lab and NREL are collaborating on several analyses exploring the implications of retail electricity reforms on DERs and utility system economics as part of a GMLC project (4.2.3. Future Electric Utility Regulation). One of the analytical topics will explore EE and distributed PV (DPV) customer bill savings under emerging DER retail rate designs. Many DER retail rate designs are shifting towards time-dependent pricing and tend to favor more flexible and dispatchable DERs that shift load. EE and DPV, however, are less flexible and non-dispatchable, which may erode customer bill savings. The analysis will assess the range of customer bill impacts of EE and DPV investments under alternative DER rate designs (e.g., TOU, midday load building rates) to identify the least and most beneficial DPV system designs and EE measures from the customer perspective.

Role of wholesale prices in the analysis: Cambium marginal capacity and energy costs will be used for a comparison of customer bill savings and utility system benefits. The comparison will inform whether DER rate designs over- or under-value EE and DPV customer bill savings relative to marginal system value (i.e., are DER rate designs over- or under-compensating EE and DPV investments?).

Key characteristics of wholesale prices needed to conduct the analysis: The proposed analysis will use marginal capacity and energy costs. Specific scenarios and geographies will be identified later.

Suitability of Cambium costs for this particular project: Cambium was selected because it is publicly available and can capture the time-dependent value of EE and DPV across a range of EE measure types and DPV system designs.

5.7 Distributed PV+Storage Net Billing Analysis

Lead Contact: Galen Barbose, glbarbose@lbl.gov
Goal of the analysis: This analysis evaluates the economic efficiency of moving towards net billing tariffs for behind-the-meter (BTM) solar systems. The project emphasizes the importance of aligning utility rates and price signals with grid value. It will evaluate how a BTM battery/solar system owner may operate their system under net billing tariffs in order to maximize self-consumption of solar, and how well that operational strategy aligns with bulk system energy and resource adequacy needs.

Role of wholesale prices in the analysis: A key element of this analysis will be to estimate the energy and capacity value of BTM storage operation under net billing tariffs. Wholesale energy and capacity prices will be used to perform that valuation.

Key characteristics of wholesale prices needed to conduct the analysis: The analysis will estimate energy and capacity value based on both historical wholesale prices as well as projected future prices. It is for that latter, forward-looking component that Cambium data would potentially be used. For that analysis, we would want hourly busbar energy, load, capacity, ancillary service, and emission estimates. We would want data for each balancing authority, though ultimately we might choose to present results only for a subset. In terms of the timeframe, we would want projected prices for at least 10-20 years out into the future.

Suitability of Cambium costs for this particular project: The purpose of the forward-looking component in our analysis is to characterize the performance of net billing tariffs under futures with much higher levels of grid-scale VREs than exist today (as will be reflected in our accompanying analysis based on historical wholesale prices). The availability of Cambium marginal cost forecasts for multiple scenarios, across varying VRE penetration levels, make it ideally suited for this analysis.

5.8 Future Drivers of Retail Rates Project

Lead Contact: Pete Cappers, pacappers@lbl.gov
The Cambium data served as one of several data sources for developing forecasts of electric utility fuel

and purchased power budgets over the next 10 years. Specifically, the data was used to develop a range in growth rates in energy and capacity prices over this time period. There is no utility that buys 100% of their energy or capacity from the spot wholesale market. Instead, most utilities in organized wholesale market environments heavily rely on short-term and/or long-term power purchased agreements, with spot-market purchases comprising only a relatively modest share of the portfolio. In addition, using marginal costs derived from wholesale power markets is not a great proxy for average power costs which must be recovered from ratepayers of vertically integrated utilities. As such, the direct applicability of the derived growth rates was somewhat limited for this project's narrow analytical purposes. The derived ranges in growth rates were used, along with other data sources, to benchmark the growth rates for aggregate fuel and purchased power costs ($/MWh) that were ultimately used in the analysis.

5.9 Utility-scale PV Distribution Feeder Integration

Lead Contact: Sydney Forrester, sforrester@lbl.gov

Goal of the analysis: Developers exploring mid-sized solar PV systems (1-5 MW) on distribution feeders that are approaching their hosting capacity can be constrained to smaller system sizes or required to pay for costly infrastructure upgrades to avoid potential peak loading, voltage, and/or power quality issues. As an alternative, the Rhode Island Office of Energy Resources, National Grid, NREL, and Berkeley Lab are developing an Operating Envelope Agreement (OEA), which is a mechanism that would allow the developer to install a larger PV system if they agree to control any exports from their system during predefined, critical periods. This could be achieved with co-located storage operated to control solar generation during the hours or days specified in the OEA. The project consists of developing the framework and content of the OEA itself, a distribution system impact analysis that informs the rules to be enforced by the OEA, and an economic comparison of the various options from the viewpoint of the developer.

Role of wholesale prices in the analysis: Since the OEA only requires the storage to be dispatched during few critical days or hours, the storage system may be able to take advantage of secondary value streams while not being used to mitigate issues from the solar system. Berkeley Lab plans to use Cambium marginal costs to co-optimize storage dispatch and quantify the secondary value streams. The goal of the economic analysis is to compare the developer's costs and revenues for the following configurations: (1) smaller PV system size, (2) larger PV system size with distribution upgrades, (3) larger PV system size with curtailment, and (4) larger PV system size with collocated storage system. We will consider energy, ancillary service, and capacity market value over the lifetime of the storage system.

Key characteristics of wholesale prices needed to conduct the analysis: To match the typical battery lifespan, we plan to use marginal costs for the Rhode Island balancing area in the MidCase scenario for 2020 – 2030. In our case, we want to use values comparable to market prices and plan to use the busbar energy marginal costs. We are not yet certain whether we will use the capacity costs, given that we intend to account for the actual forward capacity market's auction results and rules. We plan to look at differences across Cambium 2018, 2020, and 2022 capacity costs versus auction results to determine a course of action. Regardless, even if we use historical auction data, we may pair it with hourly Cambium load projections to identify when dispatch may be required to capture capacity value. For ancillary services, we plan to similarly compare actual 2018 and 2020 market value vs. Cambium data to assess the magnitude of revenue and ensure that it may suffice. Finally, we may consider additional Cambium scenarios for sensitivity analyses.

Suitability of Cambium prices for this particular project: Having a full year of hourly price estimates at this geographic scale is extremely helpful for our project. We are concerned that Cambium over-estimates energy costs by $4.40/MWh on average (and has a median that is $10.96/MWh higher) across 2018 and 2020. We also note additional quirks, such as the annual peak price hour rising extremely high from an otherwise-average priced day and then falling back again, which may affect arbitrage value on a specific day. However, the general price pattern was consistent with energy market prices, and we believe that overall it should provide a good estimate for a 10-year value stream. On the other hand, we plan to do a more in-depth comparison for the capacity and ancillary service values, as they may not exactly be representative of the market itself. Even if we decide to create near-term projections based on past value, we may still be able to use other Cambium data (e.g., load) or temporal value patterns to inform our adaptation of historical data to future predictions.

5.10 Large Rotor Benefits for Wind Turbines

Lead Contact: Dev Millstein, dmillstein@lbl.gov
Berkeley Lab's analysis (Wiser et al. 2020) investigated the benefits of increased wind turbine rotor designs that allow for increased electricity generation even at low wind speeds. We paired simulated hourly production output with coincident wholesale electricity prices to estimate a value premium. We found that decreasing turbine specific power from 230 to 150 W/m2 and increasing hub height up from 88 to 140 m led to a value premiums of roughly $1.4/MWh based on historical nodal energy and capacity pricing and $0.5/MWh based on LCG 2030 pricing. Cambium prices might be suitable for replicating this type of analysis at higher wind penetrations across the continental U.S. if key data related to meteorological assumptions were more readily available, including geographically resolved wind speeds at various hub heights.

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