The Importance Of Fast-Start Pricing In Market Design: Including The Cost Of Starting And Operating Natural Gas Peaking Units In Wholesale Market Prices

Prepared By Powerex And Public Power Council (PPC) June 2022

Table Of Contents

Executive Summary

This paper examines the impact of differences in one of the key price formation areas of organized wholesale electricity markets: whether or not the cost of starting and operating natural gas peaking units is included in wholesale market prices, also known as "fast-start pricing." In bilateral transactions, both buyers and sellers generally consider the cost of starting and operating peaking units when negotiating the price of a transaction. FERC has also recognized that the cost of a decision to start and operate a so-called "fast start" unit "represents a marginal cost that should be reflected in prices." As of 2022, five of the six FERC-jurisdictional organized markets include the cost of starting and operating natural gas peaking units in their calculation of wholesale market prices. The exception is the markets operated by the CAISO, where fast-start pricing has been actively opposed by both the CAISO and by its Department of Market Monitoring. Under its current market design, CAISO-operated markets generally exclude the costs of starting and operating natural gas peaking units from the calculation of the wholesale market prices, and instead rely on side payments from the market operator to the individual units to enable them to break even on their variable costs across each day.

To better understand the frequency, magnitude, and impact of the CAISO-operated markets excluding the cost of using natural gas peaking units from the calculation of CAISO market prices, Powerex and Public Power Council (PPC) commissioned a highly detailed analysis using publicly available data on hour-by-hour unit output for 2017-2020 for the Pacific Northwest, Southwest and California regions. This analysis shows that:

- Natural gas peaking units are routinely started during the evening peak hours year-round, and also during the morning peak hours during the winter months. The short-duration dispatch of fossil-fueled units to meet demand in peak hours is particularly common in the Southwest and in the southern (SP-15) sub-region of California.
- When these natural gas units are started and operated to meet peak demand, there is a large "gap" between what the market prices would be if they included these costs and the actual market prices calculated in the CAISO markets (which excludes them). For example, between 2017 and 2020, the average market price in SP15 between 6 p.m. and 7 p.m. was approximately $23/MWh less than if the cost of starting and operating natural gas peaking units had been included in the calculation of the market price; in NP15, it was nearly $15/MWh less.

The lack of fast-start pricing in the CAISO-operated markets has direct economic consequences for all entities that sell or purchase wholesale electricity at market prices in CAISO-operated markets (including in the Western EIM):

1. It is estimated that California loads benefit by approximately $1.3 billion per year, as the market prices at which California load-serving entities purchase wholesale electricity to meet demand is suppressed below efficient and accurate levels. This estimate assumes that California load ultimately purchases all of their supply from the wholesale market, over various time horizons, from both merchant generation and imports.

2. In-state generators are harmed by selling their output at suppressed market prices. This economic harm is not limited to fossil-fueled merchant generating units, but also to the kind of non-emitting resources that are vital to achieving environmental policy goals. For example, it is estimated that in 2020, market revenues for wind resources in northern California were suppressed by approximately 9%, whereas revenues for a four-hour battery storage resource were suppressed by approximately 34%.
3. Northwest and Southwest ratepayers are harmed by receiving $188-420 million per year less for wholesale sales to California due to suppressed market prices. Load-serving entities typically rely on revenues from off-system sales to lower their retail electricity rates, as it reduces the revenues that must be recovered from their own ratepayers.

In addition to creating transfers of significant value to California load interests (at the expense of external ratepayers and internal wholesale sellers, particularly renewable resources and storage), and undermining the accuracy of wholesale market prices in general, the lack of fast-start pricing in CAISO's markets has numerous additional adverse consequences:

1. **Discriminatory compensation:** Entities that provide the same service (*i.e.,* that provide electricity to meet demand in peak hours) do not receive the same compensation, as the CAISO subsidizes the dispatch of fossil-fueled peaking resources through uplift payments to these resources, but does not make comparable compensation to all other resources that produce and sell wholesale electricity in the same hours.
2. **Inefficient use of clean, flexible Northwest hydro resources**: CAISO market prices do not provide a strong price signal for clean energy-limited resources to shape their output into the hours of peak demand through the CAISO's organized markets; these resources may instead find more attractive opportunities selling their output in the bilateral markets as flat 8-hour and 16-hour products, where the costs of starting and operating fast-start resources are reflected in market prices.
3. **Weakened carbon-pricing programs:** The calculation of wholesale market prices in CAISO-operated markets not only excludes the cost of starting and operating natural gas peaking units, it also excludes the cost of GHG emissions from those units, which can be among the highest in the grid. This undermines a key goal of carbon pricing programs, including California's cap-and-trade program as well as programs being explored by multiple other western states.

The above leads to a clear and compelling conclusion: any day-ahead and real-time organized market platform that develops in the west must include the cost of starting and operating peaking units in the calculation of wholesale market prices. Transitioning to a full organized market without fast-start pricing would cause significant economic harm to ratepayers in the Northwest and Southwest sub-regions of the west, and will fail to produce the accurate and efficient wholesale market prices necessary to support the deep decarbonization of the western grid while maintaining reliability and keeping electricity affordable for ratepayers.

Accurate Wholesale Market Prices Must Include The Cost Of Starting And Operating Natural Gas Peaking Units

Absent scarcity conditions, wholesale market prices in organized markets are intended to reflect the increase in system wide costs associated with serving an additional increment of demand. However, absent special pricing provisions such as "fast start pricing", only those resources that can quickly adjust their output up or down are eligible to set the wholesale market price. In simplified circumstances, this eligibility requirement helps ensure that wholesale market prices reflect the incremental cost of energy in each market interval. But as FERC explained in 2016, "this eligibility requirement can distort [wholesale market prices] when a fast-start resource is committed and dispatched to serve expected load during a particular interval."[1] FERC went on to explain that:

> *We preliminarily find that given the unique operating characteristics of fast-start resources, their commitment costs, i.e., start-up and no-load costs, should be viewed as marginal costs and, as such, should be included in prices.*[2]

In other words, even though many fast-start resources, such as natural gas peaking units, may not be able to adjust their output up or down for the next market interval, FERC's policy is that they should be included in the calculation of wholesale market prices. As of 2022, five of the six FERC-jurisdictional organized electricity market operators have designed their markets to include the costs of starting and operating fast-starting peaking units in the wholesale market prices for electricity. The exception is the markets operated by the CAISO, whose market design approach continues to exclude those costs.

CAISO's History Of Opposing Fast-Start Pricing Is Consistent With The Disproportionate Influence Of California Ratepayer Interests In The CAISO's Governance Structure

The CAISO and its DMM division have repeatedly opposed FERC's efforts to require organized markets to implement robust "fast-start pricing" provisions. Notably, DMM's opposition was not limited to arguing against changes to the CAISO markets in particular; DMM also intervened in multiple FERC proceedings unrelated to the CAISO's markets to argue against recognizing the cost of starting gas peaking units in NYISO, PJM and SPP. DMM claimed that fast-start pricing "would contradict a basic principle of economic theory that has been accepted for over 70 years[.]"[3] But DMM's comments also revealed a concern regarding the level of wholesale market prices:

> *Under the fast-start pricing rules, fast-start resources would not be compensated any more than under the current pricing rules. Rather, the source of the payment would simply shift from bid cost recovery to energy market payments. However,*

[1] *See* FERC Notice of Proposed Rulemaking in Docket No. RM17-3, Fast-Start Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators, (December 2016), at 8.

[2] *Id.* at 51.

[3] DMM NOPR Comments, at 4.

> ***resources that are less expensive than the market clearing price would be paid substantially more through a higher market clearing price***.[4]

The opposition of the CAISO and of its DMM division to including the cost of dispatching fast-start natural gas peaking units in the wholesale market price of electricity is out of step with the view of FERC, as well as that of other organized markets and their respective market monitors. It is also entirely out of step with the existing bilateral markets, where sellers will include the cost of starting and operating a fast-start unit in their offer prices and purchasers will include the costs saved by *not* starting and operating a fast-start unit in their bid prices. But the CAISO's and its DMM's opposition to fast-start pricing—which has the effect of appropriately raising wholesale market prices during the hours that fast-start units are operating—appears fully consistent with the CAISO's historical governance structure and its statutory requirement to act for the benefit of California ratepayers.[5] Entities and regions outside of California are very differently situated, however, and include a wide cross-section of circumstances, interests and priorities. There are also generators within California—including not only merchant fossil-fueled generators but also renewable resources and battery storage resources—whose interests are not served by the positions taken by CAISO and its DMM division.

Analysis Of Public Data Shows Extensive Use Of Fast-Start Natural Gas Peaking Resources In The Markets Operated By The CAISO, But CAISO Market Prices That Are Significantly Below The Cost Of These Resources

In order to better understand the ramifications of the CAISO's continued exclusion of the cost of committing and using natural gas peaking units from its calculation of wholesale market prices, Powerex and PPC engaged EnergyGPS to conduct an extensive, highly detailed analysis of public generation data from 2017 to 2020.

This analysis examined the hour-by-hour generation output from all fast-start units across the bulk of the Western Interconnection, and identified instances in which a fast-starting natural gas peaking unit appears to have been started and used for only a short period. The effective running cost of the most expensive such unit was then compared to the CAISO market prices for that hour to estimate the "gap" between prices as calculated under the CAISO current market design and what they might be if the CAISO adopted fast-start pricing, similar to all other FERC-jurisdictional organized markets.

As discussed below, the EnergyGPS analysis found frequent short-duration use of natural gas peaking units, and also found that the CAISO market prices were materially below the levels

---

[4] DMM NOPR Comments, at 26. (Emphasis added)

[5] The filings by the CAISO and DMM against FERC's action on fast-start pricing were not the result of a stakeholder process or any other consultation with market participants, but rather appear to reflect the perspectives of these institutions.

consistent with the use of such units as the marginal resource to meet demand[6]. The complete report by EnergyGPS on its analysis is attached as Appendix A.

Natural Gas Peaking Units Are Used Extensively, Particularly In California And The Southwest

Across the WECC footprint analyzed (which included the Pacific Northwest, Southwest, Northern California and Southern California sub-regions), EnergyGPS identified over 16,000 short-duration dispatches of peaking units per year from 2017 to 2020.[7]

Number Of Hours With Short Dispatch Of Gas Units

		2017	2018	2019	2020	All Hours
All WECC	Hours	6,012	6,067	5,692	5,953	23,724
	%	*68.6%*	*69.3%*	*65.0%*	*67.8%*	*67.7%*
Pacific Northwest	Hours	1,672	1,431	682	871	4,656
	%	*19.1%*	*16.3%*	*7.8%*	*9.9%*	*13.3%*
NP15	Hours	2,906	3,088	2,618	2,692	11,304
	%	*33.2%*	*35.3%*	*29.9%*	*30.6%*	*32.2%*
SP15	Hours	3,502	3,489	3,486	3,359	13,836
	%	*40.0%*	*39.8%*	*39.8%*	*38.2%*	*39.5%*
Southwest	Hours	4,597	4,251	4,248	4,313	17,409
	%	*52.5%*	*48.5%*	*48.5%*	*49.1%*	*49.6%*

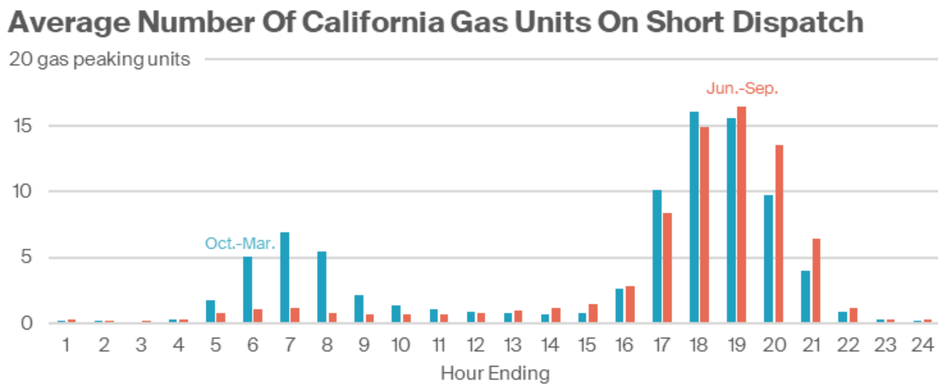
Source: EnergyGPS analysis, Appendix A at 9.

EnergyGPS found that short-duration dispatches of peaking units were most frequent in the Southwest, where in approximately 50% of all hours at least one peaking unit had a short-duration dispatch. Short-duration dispatches of peaking units were also common in the CAISO's southern (SP-15) sub-region (39% of hours) and its northern (NP-15) sub-region (32% of hours). Peaking units were dispatched for short durations far less frequently in the Pacific Northwest, where flexible hydro resources provide similar service.

EnergyGPS also looked at the months and the hours of the day in which short-duration dispatches of peaking units were most common. They found that the average number of short-duration dispatches in California was highest during the evening peak hours year-round, and also during the morning peak in the winter months.

[6] The EnergyGPS analysis was compiled from various sources of publicly available data and required developing criteria for identifying instances in which a fossil-fueled unit was started for a short duration to meet demand. The analysis was thorough and all reasonable efforts were made to ensure accuracy, and Powerex and PPC are confident in the direction and relative magnitude of the results. Nevertheless, entities with direct access to the actual market data, software, and outputs are undoubtedly in a position to undertake a more refined analysis.

[7] EnergyGPS analysis, Appendix A, at 9.



Source: EnergyGPS analysis, see also Appendix A at 11-12.

CAISO Market Prices—Including In The Western EIM Footprint—Would Be Substantially Higher In Some Hours If They Included The Cost Of These Fast-Start Natural Gas Peaking Units.

EnergyGPS also estimated the impact of including the cost of starting and operating these peaking units on the CAISO's calculation of the market prices. More specifically, EnergyGPS calculated the difference, if any, between:

1. The effective variable cost of a peaking unit on a short-duration dispatch; and
2. The CAISO's average real-time market price at the respective hub in the same hour.

EnergyGPS estimated that including the costs of short-duration dispatches of natural gas peaking units would result in wholesale market prices that were significantly higher during the hours that fast-start units are used most often: the evening peak hours year-round, and the morning peak hours of winter months. The table below shows the average of the price impacts identified by EnergyGPS for each region across different hours of the day between 2017 and 2020.[8] For the evening peak hour from 6 p.m. and 7 p.m., this price impact averaged nearly $15/MWh in NP15, and nearly $23/MWh in SP15.

[8] The table shows the average value of the price impacts calculated by EnergyGPS, excluding hours in which the CAISO market price was less than $20/MWh, since short-duration dispatches at these price levels may be more likely to indicate local reliability needs. *See* Appendix A, at 28.

	Hour Ending																									
	Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Average
SP15	2017	0.40	0.34	0.10	0.12	0.33	5.52	10.56	8.11	5.84	4.60	4.42	3.70	3.19	4.03	4.01	3.30	7.10	14.94	21.75	22.23	19.63	5.64	1.78	0.55	6.34
	2018	0.55	0.82	0.20	0.41	2.86	11.23	17.13	13.02	8.42	8.33	5.57	4.69	5.12	5.88	8.47	9.42	14.42	24.47	29.13	27.44	16.11	6.42	2.67	2.21	9.37
	2019	1.69	0.95	0.69	0.43	1.66	8.25	11.21	9.89	7.50	6.06	4.58	4.03	4.86	3.88	3.68	4.59	8.67	17.34	21.21	17.59	11.22	5.54	1.77	0.77	6.59
	2020	1.42	1.62	0.68	0.41	1.15	3.04	6.26	5.66	4.13	3.51	2.21	1.29	1.17	1.37	2.03	3.52	8.92	15.06	19.30	15.46	7.97	2.85	0.91	0.71	4.61
NP15	2017	0.74	0.44	0.13	0.14	0.39	3.37	6.05	3.68	2.26	1.64	1.81	1.49	2.12	1.62	1.17	1.47	6.00	13.58	19.73	16.38	9.45	3.29	0.74	0.30	4.08
	2018	0.49	0.68	0.43	0.72	1.66	5.11	6.66	5.43	2.59	0.85	1.87	2.49	1.85	2.36	1.87	2.69	5.76	11.74	15.19	11.88	7.61	2.86	0.96	0.87	3.94
	2019	0.29	0.39	0.08	0.34	0.40	3.58	5.18	4.14	2.06	1.54	0.70	1.03	1.33	1.02	0.86	1.98	4.70	11.13	12.75	9.10	5.02	1.15	0.63	0.53	2.91
	2020	0.76	0.76	0.24	0.34	0.49	2.09	3.86	2.92	1.35	0.61	0.69	0.94	1.15	0.84	0.63	1.97	5.15	10.50	12.00	7.78	3.99	1.46	0.56	0.32	2.56
Southwest	2017	0.61	0.64	0.79	0.44	0.44	1.03	3.21	5.83	8.29	6.49	3.48	2.64	1.79	1.83	2.11	2.10	2.29	2.74	4.27	5.39	5.34	4.96	2.98	1.41	2.96
	2018	0.28	0.19	0.13	0.05	0.15	0.63	1.47	2.50	2.91	2.18	1.49	0.69	0.84	0.81	1.05	1.07	1.20	1.55	1.73	1.79	1.67	1.45	0.73	0.32	1.12
	2019	0.30	0.05	0.05	0.02	0.03	0.16	0.16	0.47	1.55	1.21	0.77	0.53	0.47	0.52	0.44	0.29	0.42	0.53	0.62	0.62	0.74	0.20	0.01	0.12	0.43
	2020	0.15	0.16	0.14	0.16	0.16	0.32	0.78	0.91	1.88	2.25	1.66	1.15	1.33	0.73	0.76	0.57	0.63	0.85	0.83	0.80	0.55	0.74	0.22	0.19	0.75
Pacific Northwest	2017	0.78	0.75	0.65	0.96	0.71	1.12	2.63	3.20	4.59	4.05	2.54	1.70	1.72	1.38	1.10	1.84	1.76	2.37	2.47	2.99	2.48	2.64	1.79	1.67	2.00
	2018	0.91	0.68	0.73	0.71	0.96	1.99	1.69	3.74	2.86	2.86	2.44	1.97	2.15	1.70	1.68	3.69	1.93	1.91	2.27	1.73	1.20	1.75	1.29	1.12	1.83
	2019	0.14	0.38	0.19	0.31	0.33	0.33	0.49	0.64	0.96	0.93	0.44	0.35	0.33	0.43	0.38	0.33	2.37	2.01	2.30	0.86	0.55	0.41	0.19	0.16	0.66
	2020	0.30	0.45	0.12	0.32	0.17	0.17	0.29	0.61	0.78	0.86	0.99	1.28	0.85	0.77	0.70	0.58	0.81	1.10	1.58	1.10	0.73	0.28	0.10	0.04	0.62

Source: EnergyGPS analysis, see also Appendix A at 17.

Notably, EnergyGPS estimated the price impacts considering each region on its own, and under the assumption of no impacts to prices in other regions. In reality, adopting fast-start pricing in any of these regions would result in a stronger price signal for more efficient resources to be delivered from other regions during peak hours, resulting in improved efficiency of inter-regional trade and an increase in the wholesale market prices in the exporting regions.

Who Benefits And Who Is Harmed By Excluding The Cost Of Fast-Start Peaking Units From CAISO Market Prices

When wholesale market prices are distorted below accurate and efficient levels, a key result is a shift in the value of wholesale electricity transactions between buyers and sellers. EnergyGPS quantified the economic benefit and economic harm when CAISO market prices are below the levels that reflect the cost of starting and operating fast-start peaking units.

The Market Cost Of Wholesale Electricity Purchases To Meet Load in the CAISO BAA Was Reduced By An Average Of $1.3 Billion Per Year During 2017 - 2020

As a full organized market, all load in the CAISO BAA is financially settled as purchases at the applicable wholesale market price. Based on the hourly price impacts calculated in its study, EnergyGPS determined that the total cost of wholesale energy purchases to meet load in the CAISO BAA was reduced by an average of $1.3 billion per year due to excluding the cost of fast-start peaking units from the calculation of wholesale market prices.[9]

Lower wholesale energy costs benefit California load-serving entities that are large net purchasers of wholesale electricity to meet their retail demand, particularly during the evening and morning peak hours in which fast-start units tend to be used more frequently. In practice, however, the total cost savings for California ratepayers is likely less than the value calculated by EnergyGPS because some load-serving entities in the CAISO BAA have retained a portion

[9] As noted previously, the hourly price impacts calculated by EnergyGPS were not applied to hours in which the CAISO market price was below $20/MWh, which is more likely to indicate a short-duration dispatch for local reliability needs. *See* Appendix A, at 28.

of their generating units (which would benefit from including the cost of fast-start peaking units in the calculation of wholesale market prices, which would lead to higher-priced wholesale sales). Nevertheless, a significant majority of load in the CAISO BAA is served by wholesale purchases from unaffiliated generators and importers, indicating that the magnitude of savings associated with excluding peakers from market prices in the CAISO BAA is considerable.[10]

In-State Generators—Including Renewables And Storage Resources—Are Directly Harmed

Every dollar saved by California loads when wholesale market prices are suppressed also represents a dollar of economic harm to sellers of wholesale electricity.[11] While imports of electricity (discussed below) are a critical part of supply to the CAISO BAA, the majority of the resources that sell their output at prices based on CAISO market prices are located within the CAISO BAA. This means that much of the benefit to California ratepayers of suppressed wholesale market prices causes economic harm to other in-state interests, including not only fossil-fueled merchant generation, but also:

- **Renewable resources, particularly wind.** Applying the hourly price impacts calculated by EnergyGPS to the hourly output of wind facilities located in northern California shows that those wind resources lost approximately $2.30/MWh in average market revenue, or 9% of their total market revenues. Similar impacts are likely for wind resources in the CAISO's southern sub-region (SP-15) and in other sub-regions, including the large amount of wind installed in Bonneville's BAA.
- **Battery storage projects.** Applying the hourly price impacts calculated by EnergyGPS to the modeled operation of a four-hour battery in the CAISO's southern sub-region (SP-15) shows that a battery storage resource lost approximately $15/MWh in average market revenue in 2020, or 34% of its total market revenues.

Southwest And Northwest Sellers To California Are Also Harmed By Suppressed Prices

An important share of the wholesale electricity that serves CAISO load is produced outside of the CAISO BAA, which means that the economic harm of suppressed wholesale market prices is borne by entities outside of the CAISO. More specifically, suppressed wholesale market prices directly harm:

- **Southwest load-serving entities that make surplus sales to California during morning and evening peak hours.** Applying the hourly price impacts calculated by EnergyGPS for Southern California (SP-15) to electricity deliveries to California from Nevada or Arizona shows an estimated suppression of the value of Southwest imports of

[10] While some of the wholesale purchases to meet California load may be made outside of the day-ahead and real-time organized markets, forward market prices generally reflect the expectation of day-ahead and real-time prices in the organized markets. Hence the rules for calculating market prices have a *direct* impact on day-ahead and real-time prices in the organized market, and also a similar *indirect* impact on forward prices.

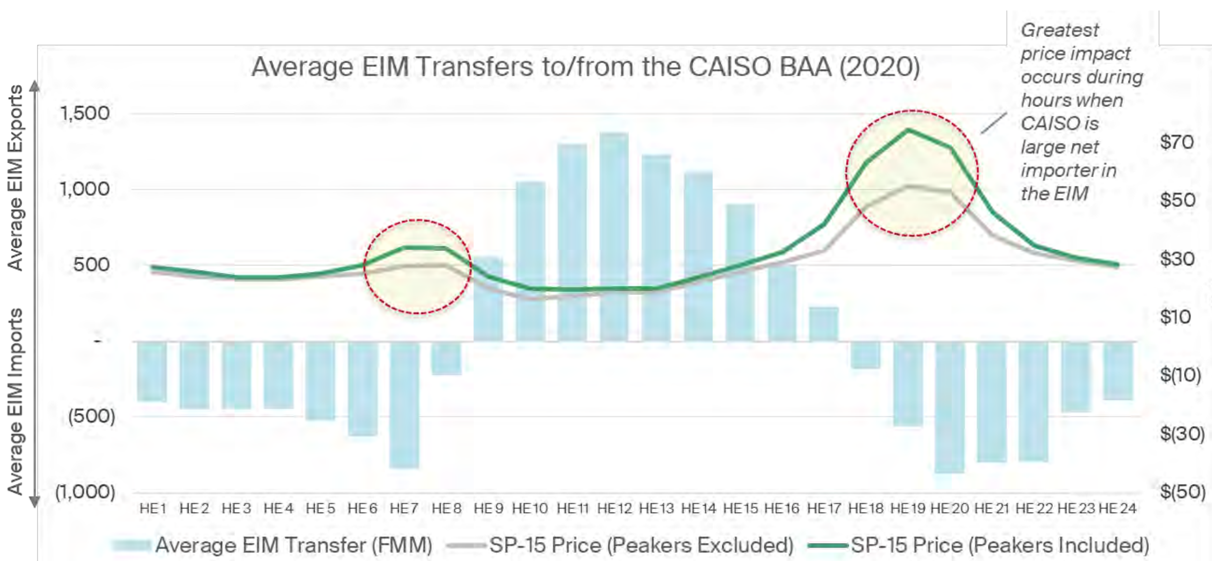
[11] There are additional detrimental consequences of inaccurate market prices, as discussed in the next section.

$95-$235 million per year.[12] Imports into California from the Southwest are generally not constrained by transmission limits, hence this impact would largely translate to reduced surplus sales revenues for Southwest entities.

- **Northwest load-serving entities that make surplus sales to California during morning and evening peak hours.** Applying the hourly price impacts calculated by EnergyGPS for Northern California (NP-15) to electricity deliveries to the CAISO BAA on the Pacific AC and Pacific DC Interties shows an estimated suppression of the value of Northwest imports of $93-185 million per year.[13] This impact would result in reduced surplus sales revenues for Northwest load-serving entities, reduced value for transmission customers that hold Northwest OATT transmission rights to deliver energy to California during peak hours, and also potentially reduced CAISO congestion revenues.

Western EIM Participants Are Systemically Harmed Through Suppressed Compensation For EIM Transfers When The CAISO BAA Is Importing

CAISO market prices impact not only the pricing of wholesale electricity delivered by external sellers to the CAISO boundary, they also determine the value of transfers resulting from the dispatch of participating resources in the Western EIM. The chart below shows the average EIM transfers into or out of the CAISO BAA for each operating hour (light blue bars) as well as the actual CAISO average real-time market price (gray line) and the market price if the cost of starting and operating natural gas peaking units was included in the calculation (green line).



Notably, during the hours that EnergyGPS calculates that CAISO market prices were most suppressed due to excluding peaking units, the CAISO BAA is a large importer of energy from

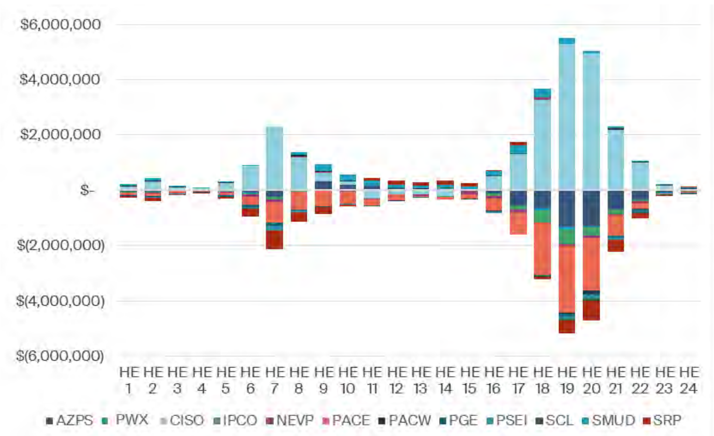
---

[12] EnergyGPS price impacts were not applied to hours in which the CAISO market price was less than $20/MWh. *See* Appendix A, slide 28.

[13] *Id.*

the rest of the EIM. Powerex and PPC estimate that in 2020 the CAISO BAA saved $23 million on the cost of EIM imports due to the lack of fast-start pricing in the CAISO-operated markets.

By the same token, EIM entities that are net exporters during the hours that wholesale market prices are most suppressed will be economically harmed by receiving inaccurately low compensation for their surplus production. Powerex and PPC applied the hourly impact calculated by EnergyGPS to EIM transfers for all EIM entities in 2020. The table below identifies the net impact on each EIM entity of CAISO market prices that exclude the cost of starting and operating peaking units:



BAA	Estimated Annual Impact		Total GWH of EIM Imports/Exports
CISO	$	23,449,970	2,853
SMUD/BANC	$	2,456,428	420
PACW	$	200,141	632
Powerex	$	(63,778)	232
SCL	$	(297,902)	114
PGE	$	(583,574)	438
PSEI	$	(644,183)	365
NEVP	$	(784,223)	542
IPCO	$	(1,944,442)	398
SRP	$	(2,991,742)	827
AZPS		(4,742,880)	775
PACE		(12,315,352)	1,322

While the above value transfer among EIM entities may appear modest in size, this largely reflects two unique factors that limit activity in the Western EIM. First, the Western EIM is strictly a market for sub-hourly activity, with volumes that are only a fraction of the transactions that currently take place in the day-ahead and real-time markets. Second, entities with flexible resources (such as Powerex) currently have the option to avoid selling the output of those resources in the Western EIM in favor of alternative transactions in the bilateral markets, where prices reflect the value of starting and operating peaking units. Importantly, both of these factors will largely cease to apply once the west fully transitions to day-ahead and real-time organized markets. At that point, the types of value shift currently observed due to a lack of fast-start pricing in the Western EIM are likely to apply to a far greater volume of wholesale transactions, and drive a significantly larger financial impact.

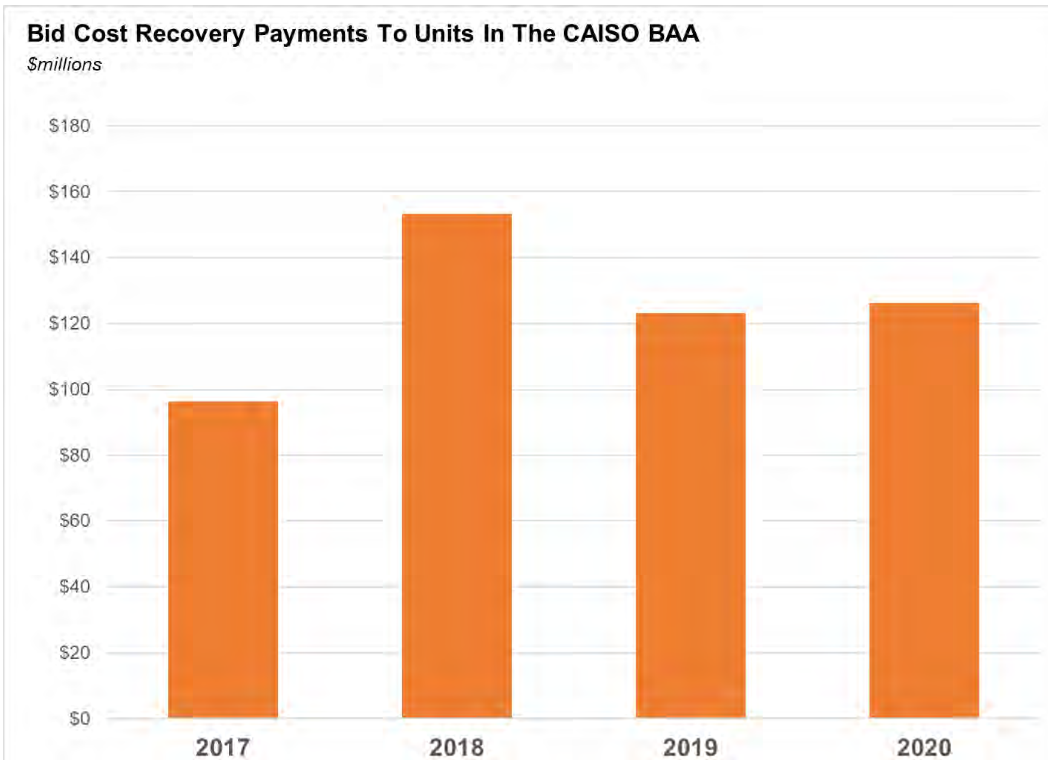
Lack Of Fast-Start Pricing Undermines Numerous Policy Objectives

The impact of suppressed wholesale market prices is not limited to shifting value from wholesale sellers to wholesale purchasers during the affected hours. Accurate wholesale market prices are vital to creating appropriate incentives for operational and investment decisions, and to enable recovery of costs. By continuing to exclude the costs of starting and operating natural gas peaking units from the calculation of wholesale market prices, the current

CAISO market design frustrates these objectives. But there are additional harmful consequences that arise specifically from the lack of fast-start pricing, as detailed below.

Lack Of Fast-Start Pricing Results In Discriminatory Subsidies To High-Emitting Gas Peakers

One of the primary symptoms of suppressed wholesale market prices is the need for additional side payments to fund production from thermal resources that otherwise would find it uneconomic to generate. This is precisely what happens when natural gas peaking units are required to start and operate in order to meet CAISO demand, but wholesale market prices exclude those costs and therefore provide insufficient compensation to those units to recover their operating costs. As shown in the figure below, the CAISO has provided approximately $125 million per year in so-called "bid cost recovery" payments, reflecting compensation in addition to the wholesale market price but that is paid almost entirely to natural gas peaking units.

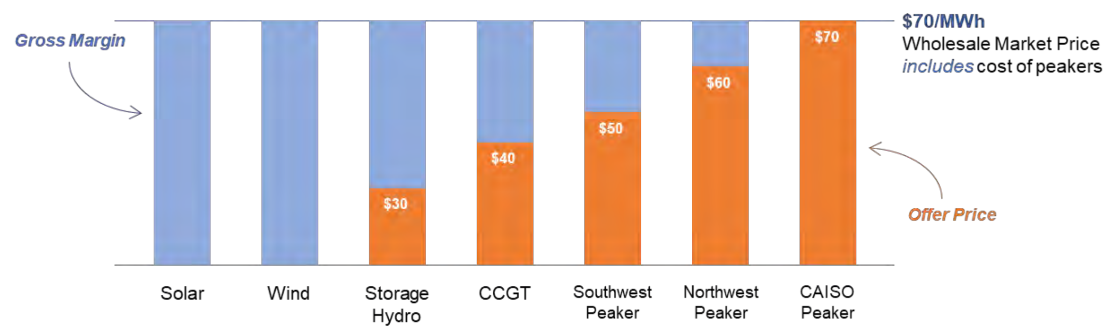


Source: CAISO Department of Market Monitoring, 2020 Annual Report On Market Issues and Performance, at 108; 2019 at 96; 2018 at 77; and 2017 at 76-77. Values exclude bid cost recovery amounts identified for the EIM area outside the CAISO balancing authority area.

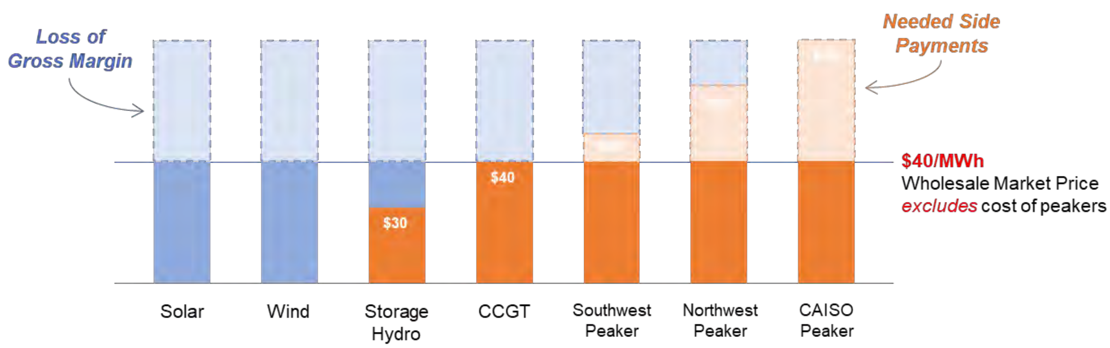
The use of side payments to provide additional compensation only to certain units results in discriminatory outcomes, since other resources that provide wholesale electricity in the same hours receive only the (suppressed) wholesale market price but without the side payments. Perhaps the clearest harm is to imports and to in-state generators, including hydro, wind and solar resources, that are not eligible to receive side payments. But the discriminatory compensation also extends to resources that are eligible for side payments, but simply receive a side payment that is just large enough to enable them to cover their own daily operating costs (as opposed to receiving an appropriate wholesale market price that reflects the marginal peaking resource, enabling them to generate revenue above their operating costs).

The graphic below shows the outcomes for a range of different types of resources. In markets where the wholesale market price reflects the marginal cost of all units dispatched to meet demand—including the cost of starting and operating natural gas peaking units—all resources receive the same compensation (top panel). In the CAISO-operated markets, however, the costs of starting and operating peaking units are excluded from the calculation of the market prices, which reduces the gross margin earned by all resources, and creates the need for discriminatory side payments to make individual resources whole (bottom panel).

Outcomes in All Other FERC-Jurisdictional Organized Markets and In Western Bilateral Markets



Outcomes in CAISO-Operated Markets



Lack Of Fast-Start Pricing Undermines The Efficient Use Of Cleaner, Lower Cost Resources To Displace The Use Of Natural Gas Peaking Units

When the full compensation of a marginal resource is not reflected in the wholesale market prices, one of the detrimental consequences is that the market prices will fail to attract alternative resources that might be available and have a lower cost. In the example above, the marginal resource had a cost of $70/MWh, but the market price was only $40/MWh. This means that an external resource that valued its output at $50/MWh would not have an incentive to offer its supply to the CAISO for that hour. That is, the CAISO’s market price signal incorrectly indicates that the $50/MWh import would not be economic, when in fact the resource represents a lower cost of meeting demand than starting and operating a natural gas peaking unit.

For example, these weak price signals prevent the CAISO from fully accessing the highly flexible clean capacity of Northwest hydro systems. These resources can provide the same flexibility to meet peak demand for short durations as natural gas peaking units. The left-hand chart below shows how Northwest hydro output is shaped into the peak hours of each day, and how this shape can shift across the year. This shows a similar shape to the output from natural gas units dispatched for short durations in the EnergyGPS analysis, which is shown on the right:

Northwest Hydro Peaking Capability (MW)

HE x	January	February	March	April	May	June	July	August	September	October	November	December
1	-2,403	-1,203	-2,043	-1,273	-1,113	-773	-1,113	-1,925	-2,071	-1,972	-1,925	-2,128
2	-2,796	-1,328	-2,254	-1,578	1,291	-941	-1,407	-2,259	-2,506	-2,243	-2,112	-2,412
3	-2,827	1,379	-2,309	-1,669	1,370	-1,046	-1,543	-2,477	-2,673	-2,327	-2,186	-2,446
4	-2,595	-1,189	-2,091	-1,485	1,299	-1,062	-1,587	-2,557	-2,711	-2,316	-2,180	-2,286
5	-2,009	-583	-1,402	-936	-1,029	-868	-1,525	-2,468	-2,620	-2,112	-1,973	-1,729
6	-745	354	407	280	-480	-654	-1,309	-2,126	-2,125	-1,240	-868	-478
7	787	1,264	1,845	1,021	-24	-659	-1,095	-1,325	-888	290	436	1,000
8	1,434	1,588	2,506	1,187	48	-290	-883	-977	-380	779	895	1,490
9	1,376	1,279	2,177	1,002	15	31	-590	-671	-334	579	802	1,174
10	1,145	636	1,296	650	211	278	-258	-319	-192	486	637	582
11	736	-16	557	365	236	365	74	136	8	434	451	146
12	318	-580	114	197	291	448	371	672	275	373	199	-270
13	17	-857	-359	-67	233	508	770	1,127	733	265	-38	-587
14	-130	-1,174	-773	-350	245	457	930	1,470	1,031	220	-229	-873
15	-136	-1,283	-983	-611	260	425	1,010	1,799	1,364	290	-219	-772
16	449	-900	-1,005	-727	291	448	1,116	1,942	1,703	509	466	577
17	1,411	196	-488	-531	568	538	1,324	2,297	2,437	1,114	1,433	1,846
18	2,146	1,108	434	322	956	776	1,561	2,472	2,866	1,893	2,216	2,520
19	2,219	1,564	1,404	1,138	1,267	846	1,640	2,418	2,879	2,323	2,176	2,404
20	1,881	1,549	1,846	1,396	1,235	745	1,515	2,046	2,603	2,201	1,862	1,994
21	1,334	1,282	1,709	1,380	983	519	1,208	1,608	1,894	1,488	1,371	1,504
22	580	679	1,009	870	624	362	662	957	846	718	709	772
23	-614	-195	-323	87	-207	-83	-136	-527	-672	-460	-633	-609
24	-1,576	-811	-1,348	-669	-651	-369	-735	-1,312	-1,468	-1,291	-1,287	-1,421

Average Peaker Output in California (MW)

January	February	March	April	May	June	July	August	September	October	November	December
7	10	4	6	7	5	7	4	11	2	8	9
6	6	2	5	4	5	7	5	6	2	4	3
3	6	2	2	3	10	8	2	5	2	1	0
3	8	11	11	7	7	16	4	10	20	6	2
12	39	90	78	29	16	25	21	42	131	53	25
96	195	295	207	79	31	33	52	90	323	187	109
257	417	351	132	46	28	27	28	70	295	304	238
239	256	138	49	33	28	15	16	31	70	158	203
89	73	46	29	31	26	11	16	29	33	51	73
47	54	37	21	28	26	15	16	27	26	30	40
39	33	26	21	22	22	17	10	25	21	19	26
30	18	22	12	19	22	25	12	20	18	15	15
34	17	28	19	21	22	46	24	24	19	15	14
19	13	23	19	20	25	39	29	25	17	14	12
16	17	21	19	17	27	49	47	34	28	16	18
18	25	16	23	17	29	61	86	92	116	101	36
143	90	64	58	49	63	139	228	291	511	429	224
511	404	321	333	271	317	442	609	678	858	732	485
478	584	728	774	671	690	691	697	651	659	428	339
245	346	519	703	726	623	469	377	276	263	168	174
81	165	173	259	353	275	153	113	65	63	50	63
18	47	38	44	62	52	29	24	9	10	12	15
4	11	6	10	11	7	10	7	2	3	12	8
4	6	7	13	7	4	11	5	8	3	13	3

But when the value of these shaped resources is not accurately reflected in CAISO market prices, it can mean that the best opportunity for Northwest hydro is often to sell under 16-hour and 8-hour bilateral transactions. It should be readily apparent that the optimal societal use of a highly flexible clean resource is *not* to sell its output as a flat multi-hour product, but that is precisely the outcome encouraged by CAISO market prices that do not include the cost of starting and operating natural gas peaking units.

Lack Of Fast-Start Pricing Undermines Carbon Pricing Programs

When the calculation of wholesale market prices excludes the costs of starting and operating a natural gas peaking unit, it also excludes the cost of the GHG emissions of those units. Natural gas peaking units tend to be relatively inefficient, as they burn more fuel per unit of electricity produced than other types of generation. There are also significant GHG emissions from the fuel used to start the unit. For example, CAISO's DMM reports that a typical new 50 MW combustion turbine would emit approximately 2.7 metric tons of CO_2 equivalent to start.[14]

[14] CAISO Department of Market Monitoring, *2020 Annual Report on Market Issues and Performance,* at 79, Tbl. 1.5. (The table reports a "GHG emission rate" of 0.053165 mtCO_2e/MMBtu, and a "Start-up gas consumption" of 50 MMBtu. The product of these values is 2.658 mtCO_2e. CAISO's OASIS reports a Greenhouse Gas Allowance Index Price of $32.46 for May 31, 2022, implying a GHG cost of $86.28 to start the unit.

These two factors make natural gas peaking units among the highest-emitting sources of electricity on the grid. A lack of fast-start pricing results in wholesale market prices that do not reflect GHG emissions in the very hours that GHG emissions are likely to be the greatest, undermining efforts to reduce emissions and meet the environmental policy objectives that GHG pricing is intended to achieve.

Conclusion

How market prices are calculated—and how those rules are decided—has the potential to shift enormous amounts of value from one group of ratepayers to another, while at the same time undermining economic efficiency and key environmental objectives. Our analysis shows that the CAISO's exclusion of the cost of natural gas peaking units in its market prices—contrary to FERC policy and contrary to every other FERC-jurisdictional organized or bilateral market—has caused significant harm to ratepayers outside of California, has led to an inefficient use of resources, has masked the carbon-related costs of electricity, and has blunted incentives for the development of new storage projects and the selection of the most beneficial renewable resources.

It should be noted that the magnitude of these impacts can be expected to grow over time. Two of the key drivers of the cost of operating peaking units are natural gas prices and the prices of GHG emissions allowances. Both of these prices are already markedly higher, on average, than they were during most of the 2017-2020 period covered by the analysis, and GHG allowance prices are forecasted to increase significantly in the years ahead.

Powerex and PPC believe that the west needs to fully transition to a well-designed day ahead and real-time organized electricity market platform in order to achieve deep de-carbonization. But it must achieve this transition carefully, recognizing the importance of accurate wholesale market prices and the large volume of transactions that will be valued based on the pricing rules of the organized market instead of the bilateral negotiations that occur today. Organized markets will only achieve their full intended benefit for all western ratepayers if they are designed to produce wholesale market prices that are efficient and accurate.

Appendix A: EnergyGPS Analysis

WECC Peaker Dispatch Analysis: Impact of CAISO Price Formation Policy on Market Outcomes

September 2021

Tim Belden
tbelden@energygps.com
503-998-5544

Policy History (1)

- Historically, standard FERC electricity market design often excluded fast-start generators from the calculation of LMPs.
  - Unit Commitment Costs (aka "startup costs"): these costs were not factored into the LMP for any type of generator.
  - Units generating at the resource's minimum operating limit (PMIN) were not able to set price.
- In December of 2016 FERC issued a NOPR proposing to require each RTO/ISO to incorporate fast start pricing into its LMPs.

Accurate pricing of fast-start resources ***"can advance price formation by more transparently reflecting the marginal cost of serving load, which will reduce uplift costs and thereby improve price signals to support efficient in facilities and equipment."***

- In December of 2017 FERC withdrew its fast-start NOPR. The Commission explained that it had been persuaded by comments that proposed reforms may not "bring sufficient value in all RTOs/ISOs." Instead, the Commission pursued a regional approach. FERC commenced Section 206 investigations in NYISO, PJM, and SPP. All three markets have adopted fast-start pricing.

Policy History (2)

- Unlike coal plants or CCGT’s, fast-start units can synchronize to the grid quickly (less than an hour and typically faster) and have minimum run times of less than an hour.
  - Peakers are often committed in real-time to meet demand
  - Peakers often have a limited operating range and are “block-loaded” at a fixed quantity.
  - Block loaded units (with limited flex) are ineligible to set price under standard LMP design.

- Fast Start Pricing provisions in NYISO, SPP, and PJM all include the following objectives:

1. Allow fast start resources to set price
   - Relax the economic minimum operating limit by 100% for purposes of calculating LMPs. This allows any fast-start unit running any setpoint between 0 and PMAX to set price.

2. Allow start-up costs of fast start resources to be incorporated into LMP.
   - These unit commitment costs are amortized across a unit’s minimum run time.

CAISO Policy

- The CAISO and DMM opposed the initial FERC NOPR and DMM intervened in the 206 investigations for NYISO, SPP, and PJM.

- The CAISO has not adopted Fast Start Pricing and therefore generally excludes peakers from the calculation of its LMPs

- CAISO **<u>includes</u>** fast start costs in its Scheduling Run and then **<u>excludes</u>** them in its Pricing Run.
  - A shift to fast-start pricing would not change the CAISO dispatch which is determined in the Scheduling Run.
  - The CAISO policy is limited to the Pricing Run and is **purely about money.**

- CAISO's failure to incorporate fast start resources into the LMP cuts against current FERC policy. Further, CAISO purports to need ever-increasing amounts of flexible ramping capability but does not want to send the appropriate price signal to the market to incent investment in resources such as storage and demand response which can provide the very service the CAISO needs.

CAISO Policy Results in Suppressed LMPs and Inaccurate Price Signals

- The price signal sent to the market does not reflect the true, short-term marginal cost of production.
- Difference between full, hourly, marginal cost of peaker and LMP revenue is conveyed separately to peaker via a side payment. These side payments are then recovered from load via an “uplift” charge.
- Peaker plants emit carbon, contribute to local air pollution, and are generally less responsive and flexible than hydro and storage resources.
- Flexible, responsive, carbon-free resources such as hydro, batteries, and other flexible CAISO imports only receive the LMP. They are not only under-compensated, but they also receive less compensation than peaker plants providing the same (or worse) service. The high degree of flexibility is not compensated and lack of unit commitment costs harms these resources.

“A decision to start a fast-start resource in real time, typically on short notice to meet some unforeseen or transient system need represents a marginal cost that should be reflected in prices.”

New York Indep. Sys. Operator, Inc., 167 FERC ¶ 61,057, at PP 23 (2019)

ENERGYGPS LLC

Study Objectives

- Determine how often fast-start (peaker) units are deployed in CAISO and throughout the WECC.

- Compare the estimated hourly marginal cost of peakers to CAISO/EIM LMPs and estimate the impact of excluding peakers from the price

- Estimate: (1) cost savings to load in the CAISO BAA, (2) inter-regional impacts associated with energy flowing to California from other regions, (3) potential impacts to revenue for Northwest hydro generation

ENERGYGPS LLC

Energy GPS Methodology to Estimate Impact of CAISO Policy on LMPs

- Time period: 2017 through 2020
- Data:
  - EPA Air Markets Program Data (hourly fuel consumption, electricity generation, and emissions) for every power plant in the United States.
  - Spot natural gas and GHG emission prices. Nodal and hub LMPs.
  - Natural gas transport rates.
  - VOM Estimates.
- Divided the WECC into four regions: PNW, NP15, SP15, DSW.
- Calculated the marginal cost by hour for each peaker dispatch during the time period.
- Compared the hourly marginal cost to the LMP that peaker for that hour.
- Calculated the positive difference, if any, between the peaker marginal cost and the hub LMP.
- This difference between peaker cost and the published LMP's reflects the impact of CAISO policy to exclude fast start costs from LMP.
- Results from one region are independent of results from other regions.

Results Part 1

- Determine how often fast-start (peaker) units are deployed in CAISO and throughout the WECC.

WECC Relies Heavily on Fast-Start Peakers to Meet Ramping Obligations and Demand

						%
		2017	**2018**	**2019**	**2020**	**All Hours**
WECC	# of Fast Starts	19,222	16,728	16,157	16,268	
WECC	# of Hours with Fast Starts	6,012	6,067	5,692	5,953	68%
PNW	# of Fast Starts	1,347	945	432	490	
	# of Hours with Fast Starts	1,672	1,431	682	871	13%
NP15	# of Fast Starts	4,288	4,111	4,188	3,789	
	# of Hours with Fast Starts	2,906	3,088	2,618	2,692	32%
SP15	# of Fast Starts	6,355	5,260	5,354	5,025	
	# of Hours with Fast Starts	3,502	3,489	3,486	3,359	39%
DSW	# of Fast Starts	7,232	6,412	6,183	6,964	
	# of Hours with Fast Starts	4,597	4,251	4,248	4,313	50%

- Peakers in the WECC were started for a short-duration dispatch more than 16,000 times in 2020. This pattern has been consistent for the 2017 to 2020 time period.
- At least one peaker in the WECC was running for a short-duration dispatch during 68% of the hours from 2017 through 2020.
- The reported data includes 25 units in the PNW, 31 units in NP15, 30 units in SP15, and 56 units in the DSW. The states of NM, CO, WY, MT, and ID are not included in this analysis.

Average Peakers Running and MWh
All Regions | 2017 to 2020

All Regions Average Peakers Running by Hour

HE x	January	February	March	April	May	June	July	August	September	October	November	December
5	1	2	5	5	3	1	1	1	2	5	2	1
6	6	10	13	9	4	2	1	2	3	11	8	6
7	11	16	17	10	4	2	1	2	4	13	11	11
8	13	18	13	6	3	2	1	1	3	8	11	12
9	9	11	7	4	2	2	2	1	2	4	6	8
10	4	6	4	2	2	3	3	2	2	2	3	4
11	3	3	3	2	2	3	3	2	2	2	2	2
12	2	2	2	1	2	3	4	2	2	1	1	2
13	2	1	2	2	2	3	4	3	2	1	1	1
14	1	1	2	2	2	3	5	5	3	2	1	1
15	1	1	2	2	2	4	5	6	4	2	2	1
16	2	2	2	2	3	5	6	8	8	8	7	3
17	9	6	5	6	6	8	12	15	20	22	22	14
18	19	19	19	19	16	17	19	22	26	30	29	21
19	21	24	27	29	25	25	24	25	26	28	26	19
20	15	20	27	31	27	25	22	20	19	17	14	12
21	8	12	17	21	21	18	15	11	7	6	6	6
22	4	6	7	7	10	8	6	4	2	2	2	2

- An average of 20 to 31 peakers are running for a fast start dispatch during most evening hours in the WECC.
- The peakers which are running produce an average between 400 MW and 1,000 MW during these evening hours.
- The maximum hourly collective peaker output exceeds 2,000 MW during many months of the year.

All Regions Peakers MWh by Hour

HE x	January	February	March	April	May	June	July	August	September	October	November	December
5	22	45	105	96	40	26	28	28	47	150	61	30
6	134	236	378	266	110	44	37	65	112	393	220	135
7	392	582	537	235	94	44	36	46	112	440	421	356
8	458	512	329	132	67	42	24	26	60	186	302	357
9	223	237	149	74	56	46	29	27	42	68	134	180
10	94	116	86	46	44	48	50	31	40	41	62	82
11	68	65	50	36	36	52	59	37	41	33	34	48
12	47	37	38	23	36	48	56	33	37	27	27	33
13	44	27	41	33	43	57	84	59	50	29	24	24
14	25	17	36	35	42	66	80	87	53	29	25	20
15	23	24	35	39	45	74	106	118	76	43	29	23
16	26	34	27	41	50	84	128	156	164	140	116	43
17	162	105	79	85	92	139	220	313	427	592	493	266
18	609	476	380	391	345	413	540	734	879	1,028	910	626
19	690	781	910	950	826	836	844	846	873	873	643	534
20	420	572	798	976	937	850	682	541	435	410	299	297
21	191	307	388	470	554	438	298	206	125	128	113	134
22	67	119	143	145	168	146	118	75	34	41	39	41

All Regions Peakers Max MWh by Hour

HE x	January	February	March	April	May	June	July	August	September	October	November	December
5	231	387	596	850	334	340	340	429	523	972	540	330
6	660	1,317	1,395	1,151	783	455	382	603	873	1,579	1,490	804
7	1,448	2,183	2,050	1,051	597	537	340	545	1,041	1,907	1,859	1,421
8	1,396	1,693	1,238	784	919	469	374	209	561	808	1,129	1,545
9	933	1,001	680	674	381	311	650	267	710	350	586	763
10	780	1,371	792	337	334	325	614	425	456	463	389	454
11	814	692	482	357	254	477	445	305	304	308	201	583
12	1,107	381	262	235	300	310	336	184	298	365	172	198
13	1,086	366	284	261	376	332	494	322	464	149	182	226
14	300	189	217	242	312	538	578	573	518	138	284	145
15	184	577	467	325	361	375	832	721	517	756	509	138
16	214	840	259	299	375	527	624	852	902	1,149	624	434
17	744	585	495	355	610	526	977	1,342	1,601	1,781	1,393	819
18	1,663	1,250	1,539	1,483	1,280	1,278	1,543	1,813	2,760	2,349	1,957	1,563
19	1,809	1,815	2,850	2,217	2,302	2,143	2,393	2,257	2,770	1,538	1,503	1,221
20	1,342	1,863	2,854	2,265	2,270	1,913	2,143	1,473	1,312	1,048	1,406	914
21	907	1,649	1,480	1,103	1,931	1,413	1,010	720	739	561	709	642
22	335	577	458	534	575	586	441	365	203	294	325	301

ENERGYGPS LLC

DSW Data subject to revision; conclusions unchanged.

Peakers Running and MWh
NP15 | 2017 to 2020

NP15 Average Peakers Running by Hour When Marginal

HE x	January	February	March	April	May	June	July	August	September	October	November	December
5	2	6	3	3	3	2	2	2	1	6	4	4
6	4	11	5	4	2	3	2	3	4	6	7	6
7	5	6	5	4	3	3	2	2	4	6	7	7
8	5	6	4	3	3	2	2	2	3	3	6	6
9	3	3	2	2	2	2	2	2	2	2	4	3
10	3	4	2	2	1	2	2	2	2	3	2	2
11	2	5	2	2	2	2	2	2	2	2	1	2
12	2	3	2	2	2	2	3	1	2	2	1	1
13	3	2	2	1	2	2	3	2	2	1	1	1
14	2	3	1	2	2	2	3	2	2	1	1	1
15	2	1	4	2	2	2	3	3	2	2	2	2
16	1	1	3	2	2	2	4	4	5	5	5	3
17	4	4	2	3	3	5	5	7	9	11	12	9
18	6	7	6	7	5	9	8	9	10	11	11	8
19	5	7	7	9	7	9	8	9	10	10	10	7
20	4	6	6	8	7	8	7	8	7	7	5	5
21	3	4	5	7	6	7	5	6	4	4	4	4
22	2	4	2	3	5	4	2	3	2	2	2	2

NP15 Highlights

- Peakers running during "When Marginal" ramp hours average from 7 to 10 units.
- Average peaker output during "When Marginal" ramp hours ranges from 200 MW to 400 MW.
- Maximum peaker output exceeds 1,000 MW during certain hours and is well above 500 MW during many of the ramp hours.

NP15 Peaker MWh by Hour When Marginal

HE x	January	February	March	April	May	June	July	August	Septemb..	October	November	December
5	57	227	135	71	68	35	90	176	105	257	239	102
6	226	325	231	127	92	120	86	179	283	335	313	266
7	356	349	181	85	86	108	96	92	147	246	365	395
8	275	215	103	56	45	67	48	55	57	86	180	258
9	116	80	51	38	51	61	54	81	33	62	104	136
10	100	112	51	57	45	75	87	82	54	76	54	53
11	97	123	24	38	49	36	83	59	42	59	46	45
12	43	67	22	32	37	69	79	48	37	45	34	32
13	88	66	43	30	51	57	146	75	53	35	41	40
14	24	50	16	31	42	69	87	67	53	21	43	33
15	48	26	99	42	65	68	132	84	29	44	40	46
16	26	37	59	26	54	47	79	60	109	123	139	77
17	148	132	85	39	73	90	82	115	241	300	274	211
18	228	205	132	130	128	213	184	249	320	383	339	293
19	216	223	225	227	219	325	260	302	312	313	216	210
20	155	162	179	215	234	284	176	220	173	173	118	159
21	115	112	107	141	158	211	127	127	96	104	87	86
22	56	153	58	74	102	96	85	85	60	65	74	71

NP15 Maximum Peaker MWh by Hour

HE x	January	February	March	April	May	June	July	August	Septemb..	October	November	December
5	229	387	242	222	164	180	197	307	352	553	350	330
6	410	602	556	399	398	301	315	399	663	817	511	642
7	647	1,080	704	259	248	439	340	269	556	905	819	1,037
8	646	787	348	226	143	161	320	209	304	351	516	716
9	274	337	240	183	113	183	166	170	313	185	212	442
10	348	652	305	139	106	212	333	215	288	291	265	355
11	212	479	261	155	145	229	296	127	268	194	126	104
12	74	381	73	53	89	224	336	107	98	90	94	139
13	344	201	216	50	106	112	340	296	141	118	143	136
14	47	107	212	123	77	220	304	276	224	43	104	132
15	83	89	410	119	244	267	336	309	311	341	132	132
16	204	128	177	53	256	347	308	205	396	626	352	334
17	327	415	309	95	190	271	296	370	819	943	658	443
18	629	601	451	379	415	649	539	696	1,096	1,102	692	784
19	545	692	758	585	692	944	711	738	954	679	670	533
20	418	678	694	688	713	753	597	705	510	507	873	494
21	299	731	428	526	479	609	442	475	434	227	528	321
22	175	344	237	233	287	370	224	225	124	150	264	219

* "When Marginal" is designed to reflect those hours when CAISO policy suppresses LMPs. It includes only those hours when one or more peakers are running in the relevant market and at least one peaker has a marginal cost that exceeds the CAISO LMP for that hour.

Peakers Running and MWh
SP15 | 2017 to 2020

SP15 Average Peakers Running by Hour When Marginal

HE x	January	February	March	April	May	June	July	August	September	October	November	December
5	1	3	5	5	2	3	4	3	3	4	3	1
6	2	6	8	6	3	2	2	2	3	6	6	2
7	6	7	8	6	3	2	2	2	2	5	4	6
8	5	6	5	3	2	2	2	1	2	3	4	4
9	3	3	2	3	2	2	2	2	2	2	3	3
10	2	3	3	2	2	2	3	2	2	2	2	3
11	3	2	2	3	2	2	2	2	2	2	2	3
12	3	2	2	2	2	2	3	1	2	2	2	2
13	3	3	2	2	3	2	3	2	2	2	2	2
14	2	2	2	2	2	2	3	2	2	1	2	1
15	2	2	2	3	2	2	2	2	3	2	2	2
16	2	3	2	3	1	2	3	4	3	5	4	3
17	7	5	3	4	4	4	5	7	8	10	9	8
18	11	11	10	10	11	8	9	10	9	12	10	8
19	10	11	13	14	11	10	9	9	9	11	8	7
20	6	8	11	13	11	10	9	7	6	6	4	4
21	3	5	5	7	8	6	5	3	3	3	3	3
22	2	2	2	2	3	2	2	2	3	2	1	1

SP15 Highlights

- Peakers running during "When Marginal" ramp hours average from 8 to 13 units.
- Average peaker output during "When Marginal" ramp hours ranges from 200 MW to 400 MW.
- Maximum peaker output exceeds 1,000 MW during many hours.

SP15 Average Peaker MWh by Hour When Marginal

HE x	January	February	March	April	May	June	July	August	Septemb..	October	November	December
5	40	138	214	192	65	89	153	165	122	225	193	47
6	70	256	305	238	123	93	92	93	127	279	245	67
7	232	359	298	162	81	66	71	69	87	206	173	195
8	162	171	146	81	65	102	49	58	59	86	89	131
9	89	99	54	61	93	70	60	44	73	59	87	70
10	88	97	88	83	81	65	70	58	68	63	74	95
11	113	61	67	105	67	69	46	50	84	59	48	80
12	81	45	60	83	63	77	84	50	57	72	40	43
13	117	65	67	71	82	72	97	64	74	50	49	51
14	81	53	51	71	71	70	70	59	68	58	50	35
15	101	65	54	76	41	60	70	68	97	47	45	57
16	74	118	45	100	39	70	88	143	112	120	100	72
17	173	105	94	99	94	107	165	226	228	353	289	190
18	434	352	287	314	376	286	380	452	396	508	430	304
19	368	434	542	582	510	472	480	444	389	381	247	208
20	193	260	357	517	526	411	331	221	180	185	115	116
21	86	153	133	184	247	151	118	78	89	86	67	61
22	66	75	62	68	60	58	59	70	55	47	42	36

SP15 Maximum Peaker MWh by Hour

HE x	January	February	March	April	May	June	July	August	Septemb..	October	November	December
5	55	215	429	628	159	184	340	285	390	555	365	54
6	113	693	881	812	415	269	338	351	404	868	663	126
7	759	1,198	1,003	643	412	156	241	195	292	885	815	503
8	489	577	539	426	302	469	231	124	157	330	279	563
9	299	426	426	182	275	159	168	119	169	198	272	250
10	411	483	424	337	258	155	219	313	216	199	388	424
11	658	227	221	357	231	383	184	89	191	164	148	362
12	316	139	154	182	202	193	242	99	144	263	99	139
13	1,058	143	197	261	198	216	389	209	177	107	182	148
14	300	184	165	242	197	149	327	261	310	134	137	89
15	184	146	132	219	101	120	495	232	311	134	154	132
16	200	831	128	299	159	303	296	488	437	331	358	191
17	410	256	303	289	232	301	545	721	565	885	960	472
18	1,082	878	772	1,195	813	892	1,063	913	865	1,116	1,073	801
19	997	1,140	1,434	1,329	1,429	1,177	1,561	1,108	947	972	706	641
20	714	861	1,371	1,276	1,303	1,197	1,152	929	589	858	372	601
21	434	932	516	554	1,118	775	594	377	479	447	227	294
22	167	294	319	225	192	245	176	199	103	138	65	82

* "When Marginal" is designed to reflect those hours when CAISO policy suppresses LMPs. It includes only those hours when one or more peakers are running in the relevant market and at least one peaker has a marginal cost that exceeds the CAISO LMP for that hour.

Peakers Running and MWh
DSW | 2017 to 2020

DSW Average Peakers Running by Hour When Marginal

HE x	January	February	March	April	May	June	July	August	Septemb..	October	November	December
5	4	4	3	3	2	3	3	3	3	2	2	4
6	7	4	5	5	4	3	2	4	4	5	5	6
7	7	8	7	6	4	2	2	5	5	7	6	7
8	9	9	8	5	4	3	2	4	4	7	6	8
9	7	8	6	3	3	6	5	3	3	4	5	6
10	4	5	4	4	3	4	6	3	4	2	3	3
11	3	3	3	3	2	4	6	3	5	2	3	3
12	3	3	3	2	3	4	4	2	4	2	2	2
13	3	2	2	2	3	4	3	3	4	3	2	2
14	4	2	2	3	4	4	4	5	3	3	2	1
15	3	1	2	3	4	4	5	8	4	2	3	2
16	1	2	2	3	4	5	6	6	5	3	2	3
17	4	3	3	5	5	5	5	7	8	5	6	9
18	8	8	7	8	6	5	7	8	9	10	9	8
19	9	10	11	11	9	11	9	12	10	9	9	8
20	8	10	13	13	10	11	10	10	9	7	7	6
21	6	8	11	11	9	9	8	7	5	4	5	4
22	4	5	8	6	7	6	6	4	3	3	3	3

DSW Highlights

- Peakers running during "When Marginal" ramp hours average from 8 to 13 units.
- Average peaker output during "When Marginal" ramp hours ranges from 200 MW to 300 MW.
- Maximum peaker output exceeds in the range of 500 MW to 750 MW during many hours.

DSW Average Peaker MWh by Hour When Marginal

HE x	January	February	March	April	May	June	July	August	Septemb..	October	November	December
5	73	46	55	73	26	96	79	66	57	78	46	53
6	116	86	96	101	89	65	48	82	80	147	97	86
7	191	164	169	129	105	52	66	121	124	193	158	168
8	257	253	168	104	62	44	44	73	76	146	166	199
9	154	157	108	63	54	93	72	54	51	67	95	133
10	67	83	69	65	54	71	113	61	65	40	60	60
11	63	68	52	44	42	84	119	78	117	51	56	61
12	60	59	62	45	44	57	61	41	80	37	38	50
13	62	36	47	51	56	77	73	73	78	48	33	37
14	51	31	44	50	70	68	74	96	61	50	42	34
15	47	32	49	68	58	72	100	122	72	52	69	41
16	25	34	37	46	80	91	136	108	92	44	34	37
17	69	43	51	71	75	104	110	136	167	92	109	112
18	136	131	108	122	108	115	144	187	189	207	181	162
19	220	216	201	230	197	170	180	222	238	225	216	187
20	182	254	338	301	225	271	245	239	210	159	151	130
21	126	163	243	207	205	200	154	132	82	90	99	87
22	68	88	143	96	120	128	118	77	50	70	58	50

DSW Maximum Peaker MWh by Hour

HE x	January	February	March	April	May	June	July	August	Septemb..	October	November	December
5	101	81	140	160	194	243	105	190	98	155	208	104
6	286	263	486	296	255	175	60	275	251	478	316	252
7	640	615	578	430	223	157	197	276	268	579	588	628
8	742	773	466	295	195	112	129	155	271	512	576	579
9	584	628	348	214	209	311	317	260	160	350	356	322
10	352	306	235	174	146	288	296	260	264	234	202	247
11	280	308	220	117	100	325	277	260	304	200	133	149
12	245	154	159	103	224	210	224	158	260	133	101	103
13	308	96	147	128	310	255	303	247	393	103	85	87
14	208	63	142	104	252	365	254	573	473	114	213	104
15	143	103	180	176	276	219	420	532	517	166	292	80
16	95	103	133	146	207	474	389	528	383	194	116	92
17	210	199	163	241	256	360	328	380	684	532	410	264
18	325	360	298	449	358	446	617	514	717	739	498	473
19	540	505	568	567	488	525	556	672	755	670	573	492
20	489	539	697	650	701	690	813	669	525	569	495	423
21	484	465	677	684	582	488	469	409	373	322	328	314
22	310	346	399	384	352	383	334	364	189	294	130	202

* "When Marginal" is designed to reflect those hours when CAISO policy suppresses LMPs. It includes only those hours when one or more peakers are running in the relevant market and at least one peaker has a marginal cost that exceeds the CAISO LMP for that hour.

DSW Data subject to revision; conclusions unchanged.

Peakers Running and MWh
PNW | 2017 to 2020

PNW Average Peakers Running by Hour When Marginal

HE x	January	February	March	April	May	June	July	August	September	October	November	December
5	3	3	2	1	2	3	2	2	3	1	3	2
6	3	2	2	3	2	3	4	2	2	2	2	1
7	4	3	3	2	2	2	2	1	2	2	2	2
8	4	3	3	2	2	2	3	2	1	1	1	2
9	3	2	3	2	2	3	3	1	2	1	2	3
10	3	3	3	2	2	2	2	1	2	2	1	2
11	2	2	1	2	2	2	1	2	2	2	1	1
12	3	2	1	2	2	1	2	2	2	2	2	1
13	2	1	2	3	2	3	2	1	2	1	1	2
14	1	1	2	3	2	2	2	2	1	1	2	2
15	1	4	2	3	1	2	2	2	2	1	2	2
16	3	1	2	2	2	3	2	1	3	1	2	2
17	4	2	2	2	3	3	2	2	3	2	2	1
18	3	2	1	2	3	2	2	2	2	2	2	2
19	3	3	2	3	2	2	2	1	2	2	2	2
20	3	3	3	2	2	2	2	2	2	2	1	3
21	2	3	3	2	2	2	2	2	2	1	1	3
22	1	2	3	2	3	3	1	2	1	1	2	2

PNW Highlights

- Peakers running during "When Marginal" ramp hours limited to 2 or 3.
- Average peaker output during "When Marginal" ramp hours ranges from 50 MW to 100 MW.
- Maximum peaker output in the range of 200 MW to 300 MW during morning ramp in winter and 150 to 200 MW during other winter and summer ramp hours.

PNW Average Peaker MWh by Hour When Marginal

HE x	January	February	March	April	May	June	July	August	Septemb..	October	November	December
5	53	24	8	37	26	23	28	17	51	22	18	18
6	37	45	50	64	27	5	41	29	41	21	58	29
7	65	64	82	100	35	38	36	18	26	56	44	60
8	120	87	92	83	53	42	40	20	36	44	56	46
9	78	70	84	56	41	37	37	36	32	33	64	58
10	36	69	69	67	36	32	34	31	43	32	58	48
11	46	43	54	62	32	26	29	51	30	34	34	47
12	47	39	50	34	43	30	40	32	21	39	27	65
13	19	23	30	40	45	65	37	27	32	46	28	74
14	17	29	34	52	37	57	36	39	33	59	49	51
15	38	31	29	57	36	57	36	38	51	49	43	51
16	38	18	19	33	37	62	40	38	59	33	38	43
17	66	49	26	36	56	49	46	36	44	48	60	36
18	78	65	30	41	38	51	54	39	41	53	58	53
19	84	65	46	55	57	40	56	54	39	52	52	62
20	64	86	65	51	53	40	57	48	47	41	37	58
21	78	52	62	46	73	54	71	50	36	41	33	53
22	42	39	56	37	53	48	56	44	33	49	44	18

PNW Maximum Peaker MWh by Hour

HE x	January	February	March	April	May	June	July	August	Septemb..	October	November	December
5	71	38	17	77	49	46	59	46	69	38	37	29
6	60	83	129	173	60	37	43	48	70	58	148	75
7	78	188	239	185	74	68	68	26	59	107	100	152
8	323	221	335	173	99	95	84	23	72	118	102	223
9	214	251	224	169	80	69	82	79	64	93	188	138
10	108	179	167	238	96	72	114	51	69	64	135	132
11	169	105	127	241	75	67	51	63	44	62	53	110
12	107	58	78	51	96	60	82	69	68	51	63	150
13	27	57	77	56	83	219	115	49	115	79	52	140
14	45	54	42	86	69	255	63	66	112	129	74	128
15	91	51	64	83	67	185	104	52	86	113	65	105
16	71	57	40	49	95	173	123	140	68	65	78	60
17	107	79	46	99	201	164	129	108	98	77	125	81
18	147	157	57	100	77	138	138	90	91	96	136	111
19	199	152	116	106	127	106	188	133	81	82	112	113
20	200	197	147	98	210	82	178	126	98	76	80	116
21	200	125	161	95	231	97	163	111	74	77	55	113
22	95	73	102	96	190	85	114	115	68	78	79	52

* "When Marginal" is designed to reflect those hours when CAISO policy suppresses LMPs. It includes only those hours when one or more peakers are running in the relevant market and at least one peaker has a marginal cost that exceeds the CAISO LMP for that hour.

2017 to 2020 Dispatch Commentary

- Largest peaker deployment occurs in Desert Southwest and SP15 during summer months.
- Peaker dispatch during the evening ramp is prevalent across all months.
- Peaker dispatch during the morning ramp is prevalent in winter months.
- PNW economic peaker dispatch is very small compared to other regions because hydro system provides similar service.
- PNW peaker dispatch is so small that PNW region must be viewed within the context of fast-start pricing in other regions.
- Energy GPS has ongoing work to identify “peaking” hydro supply which serves same role as thermal peakers.

Results Part 2

- Evaluate the price impact of CAISO policy to exclude fast start costs from LMP in NP15, SP15, the Pacific Northwest (PNW), and Desert Southwest (DSW).

- Estimate: (1) cost savings to load in the CAISO BAA, (2) inter-regional impacts associated with energy flowing to California from other regions, (3) potential impacts to revenue for Northwest hydro generation

Summary of Price Impacts by Hour

	Year o..	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Grand ..
SP-15	2017	0.52	0.34	0.24	0.19	0.62	6.77	11.84	13.31	12.95	10.47	9.10	8.22	7.37	7.38	7.45	4.32	8.20	16.96	23.49	22.33	19.90	5.64	1.78	0.80	8.34
	2018	0.91	0.82	0.37	0.67	3.61	13.27	17.84	15.56	12.77	13.70	9.66	7.40	8.03	8.50	11.51	11.49	16.59	26.75	31.60	27.98	16.26	6.76	3.11	2.45	11.15
	2019	1.91	0.95	0.76	0.59	1.87	9.35	11.86	10.92	12.48	10.56	7.78	7.23	7.58	8.99	6.95	5.94	10.52	19.44	22.41	18.22	11.88	5.88	1.95	0.88	8.20
	2020	1.62	1.95	1.10	0.98	1.67	4.48	7.25	8.21	7.34	7.94	6.72	4.46	5.00	4.87	5.23	6.34	10.64	17.50	20.31	15.89	8.25	3.03	1.01	1.05	6.37
NP-15	2017	0.82	0.80	0.96	0.64	0.56	3.88	6.76	5.71	5.94	4.08	4.06	2.67	2.97	2.83	1.98	2.22	6.60	15.92	21.80	16.63	9.77	3.63	0.84	1.04	5.13
	2018	1.08	0.98	0.81	0.89	2.33	6.55	6.91	6.33	3.73	1.31	2.34	2.88	2.45	2.89	2.41	3.29	6.16	13.45	17.96	13.34	7.92	2.94	1.07	0.87	4.62
	2019	0.37	0.51	0.38	0.54	0.67	3.84	5.44	4.88	3.20	2.42	1.59	2.55	2.49	2.31	1.45	3.22	5.95	13.19	14.10	9.65	5.23	1.31	0.63	0.62	3.61
	2020	1.20	0.81	0.24	0.69	0.84	3.04	4.67	4.17	2.48	1.64	1.87	2.31	2.02	1.52	1.01	2.65	6.67	12.02	13.49	8.50	4.29	1.63	0.63	0.45	3.29
DSW	2017	0.62	0.65	0.80	0.44	0.46	1.04	3.30	5.90	8.40	6.52	3.51	2.65	1.81	1.86	2.12	2.09	2.27	2.76	4.41	5.55	5.54	5.25	3.02	1.45	3.02
	2018	0.28	0.19	0.14	0.05	0.16	0.64	1.46	2.36	2.91	2.12	1.49	0.74	0.90	0.83	1.08	1.09	1.21	1.55	1.82	1.71	1.69	1.51	0.75	0.35	1.13
	2019	0.09	0.05	0.05	0.02	0.03	0.16	0.14	0.44	1.47	1.08	0.76	0.55	0.42	0.47	0.42	0.28	0.43	0.50	0.45	0.48	0.60	0.21	0.01	0.12	0.38
	2020	0.16	0.15	0.14	0.16	0.17	0.34	0.80	0.96	1.77	2.13	1.62	1.17	1.33	0.76	0.75	0.58	0.65	0.95	0.92	0.93	0.78	0.73	0.25	0.21	0.77
PNW	2017	0.78	0.75	0.65	0.96	0.71	1.12	2.63	3.20	4.59	4.05	2.54	1.70	1.72	1.38	1.10	1.84	1.76	2.37	2.47	2.99	2.48	2.64	1.79	1.67	2.00
	2018	0.91	0.68	0.73	0.71	0.96	1.99	1.69	3.74	2.86	2.86	2.44	1.97	2.15	1.70	1.67	3.69	1.93	1.91	2.27	1.73	1.20	1.75	1.29	1.12	1.83
	2019	0.14	0.38	0.19	0.31	0.33	0.33	0.49	0.64	0.96	0.93	0.44	0.35	0.33	0.43	0.38	0.33	2.37	2.01	2.30	0.86	0.55	0.41	0.19	0.16	0.66
	2020	0.30	0.45	0.12	0.32	0.17	0.17	0.29	0.61	0.78	0.86	0.99	1.28	0.85	0.77	0.70	0.58	0.81	1.10	1.58	1.10	0.73	0.28	0.10	0.04	0.62

Regional Results:

- Each region was evaluated independently and is not impacted by outcomes in other regions.
- For example, the LMP impact in the PNW only reflects the application of fast start pricing to resources within the PNW itself.
- This approach is conservative as the market price in one region can be determined by a marginal fast-start resource dispatched in another region
- Examining the potential impacts of fast start pricing on regional trade is discussed on a later slide.

Price Impacts by Month/Hour for NP15 2017 to 2020

LMP Delta Hub New All NP15: Hours where Peaker is Marginal

HE x	January	February	March	April	May	June	July	August	September	October	November	December	Grand Total
1	40.61		25.51		26.49	21.99	19.16	14.84	21.20	16.92	23.57	91.70	23.39
2	26.17	34.07	34.03	28.05	31.88	19.80	18.54	16.27	18.33	26.15	26.65	26.31	23.55
3	28.92	19.13	32.91	37.50	30.82	33.48	16.51	17.75	29.87	27.35	31.99		25.48
4	30.68	31.68	21.59	41.39	29.62	28.27	19.65		22.86	19.77	35.42	35.31	25.95
5	35.30	13.79	17.46	29.77	28.97	22.99	18.41	6.54	0.80	15.55	11.79	27.43	20.60
6	18.28	22.31	19.42	27.21	22.27	13.57	19.15	13.87	13.74	17.50	15.66	16.88	18.48
7	14.25	17.98	19.30	23.88	30.71	19.55	16.37	14.90	14.54	16.74	17.96	14.69	17.65
8	16.49	26.94	26.30	32.76	38.90	25.72	27.48	18.26	23.67	10.59	18.64	14.26	20.69
9	24.00	34.19	42.74	34.62	37.22	32.45	21.38	24.33	32.43	17.94	28.00	20.91	27.75
10	26.27	37.09	35.92	42.70	30.18	27.77	20.85	21.86	28.95	19.90	22.68	24.35	28.28
11	24.13	41.45	34.55	37.31	29.22	24.39	18.30	19.87	27.07	18.91	35.53	28.97	28.14
12	29.22	41.83	30.92	25.47	31.74	26.74	16.05	25.96	27.64	20.40	37.22	35.68	29.94
13	34.89	40.36	27.32	35.25	30.62	29.59	21.47	20.31	23.35	21.84	25.35	26.44	26.68
14	38.07	31.80	46.03	54.45	32.98	24.48	19.24	21.03	27.87	21.58	35.88	26.81	28.56
15	23.63	31.30	15.33	33.24	28.11	26.92	21.50	20.19	33.27	19.93	30.74	26.30	24.76
16	27.65	40.75	34.84	38.11	38.95	28.15	18.47	20.49	27.54	22.32	25.28	32.63	26.29
17	20.77	33.89	39.97	31.72	27.32	25.25	23.52	26.66	23.13	28.36	28.54	18.79	26.04
18	19.47	22.00	30.05	34.47	28.35	23.42	24.87	20.76	23.91	26.00	31.59	22.90	25.23
19	19.73	24.39	25.01	29.90	27.30	19.79	19.92	18.47	24.68	26.49	29.01	24.10	24.18
20	17.13	22.43	20.47	24.91	22.56	16.32	12.48	14.28	16.85	18.93	18.66	19.95	18.91
21	13.97	15.64	16.05	21.49	18.74	14.57	13.47	12.41	14.25	13.91	16.70	15.70	15.98
22	17.55	9.28	8.95	21.38	19.07	17.43	14.92	16.27	14.63	22.81	19.10	17.90	16.54
23	27.43	27.56	11.60	7.99	19.21	19.94	19.19	19.59	27.18	16.02	15.24	27.27	20.98
24	26.77	42.08	30.86	51.72	19.91	23.79	22.12	13.83	16.09	17.65	9.33		23.68
Gra..	19.56	25.22	22.84	27.74	25.54	20.76	18.80	18.29	21.74	21.20	24.59	21.06	22.16

LMP Delta Hub New All NP15: All Hours

HE x	January	February	March	April	May	June	July	August	September	October	November	December	Grand Total
1	0.98	0.00	0.82	0.00	1.71	0.92	2.78	0.72	0.53	0.27	0.79	0.74	0.86
2	1.06	0.90	0.55	0.23	1.29	0.99	1.20	0.79	0.76	0.42	0.89	0.21	0.77
3	0.23	0.51	0.82	0.63	1.49	0.84	1.20	0.43	0.50	0.22	0.27	0.00	0.59
4	0.25	0.84	0.52	0.69	1.67	0.94	1.27	0.00	0.76	0.80	0.30	0.28	0.69
5	0.85	0.37	1.69	1.98	2.10	0.57	1.48	0.11	0.01	1.88	0.49	1.55	1.10
6	2.51	3.16	7.05	7.48	4.13	1.24	3.24	2.35	2.86	8.33	5.09	4.35	4.33
7	5.51	8.59	11.36	5.77	3.72	1.96	1.98	2.52	3.76	10.66	9.58	6.04	5.94
8	8.51	13.59	6.58	3.55	3.45	2.79	2.88	2.06	2.17	2.13	9.01	7.13	5.27
9	8.13	7.56	3.10	3.46	2.40	3.51	1.03	2.16	3.24	1.74	4.43	5.57	3.84
10	2.12	4.92	3.48	1.42	2.68	3.01	1.01	1.41	2.65	1.60	1.89	2.36	2.36
11	0.97	4.40	3.34	1.87	3.30	2.85	1.62	1.28	3.16	1.98	2.66	2.34	2.47
12	1.41	4.81	2.49	0.85	3.58	2.23	1.42	2.30	2.30	1.64	3.72	4.60	2.60
13	1.69	2.86	2.42	1.18	3.46	3.21	2.42	1.97	2.53	3.17	1.48	3.41	2.48
14	2.15	1.69	2.23	1.82	3.72	2.45	3.10	2.54	2.09	1.39	2.99	2.38	2.38
15	0.38	1.39	0.62	1.94	2.27	2.24	3.12	2.44	1.11	1.77	1.54	1.70	1.71
16	1.12	1.80	1.69	1.91	2.83	3.28	3.87	3.63	3.67	4.68	2.11	3.42	2.84
17	2.18	2.70	1.61	3.17	2.20	4.63	6.45	8.82	8.10	14.41	16.17	5.61	6.35
18	10.21	8.18	7.75	8.62	7.77	10.73	15.24	12.89	16.73	18.87	29.22	17.36	13.64
19	13.36	14.68	15.93	18.69	17.61	13.03	13.65	11.62	18.10	21.15	25.38	18.85	16.83
20	8.98	12.51	15.03	19.10	17.11	9.93	7.85	8.64	11.09	11.75	10.73	11.75	12.03
21	4.28	5.26	8.67	12.53	13.00	8.99	6.52	5.40	2.61	3.70	4.87	5.70	6.80
22	2.26	0.90	1.44	4.10	4.61	5.23	3.01	2.36	1.10	0.74	1.11	1.59	2.38
23	1.55	0.98	0.28	0.07	1.24	1.00	1.08	0.95	0.45	0.26	0.51	1.10	0.79
24	0.86	1.86	0.75	0.43	0.80	0.79	2.14	0.33	0.67	0.14	0.23	0.00	0.75
Gra..	3.40	4.35	4.18	4.23	4.51	3.64	3.73	3.24	3.79	4.74	5.64	4.50	4.16

- Left-hand matrix shows only those hours when the marginal cost of a peaker exceeds the LMP. It is the additional $ per MWh that would result in only those hours.
- The right-hand matrix takes the same money expressed in the left-hand matrix and divides that money across all hours of the year.
- Shading ties to MWh in each cell. Cells with darker shading have more MWh.

Price Impacts by Month/Hour for SP15 2017 to 2020

LMP Delta Hub New All SP15: Hours where Peaker is Marginal

HE x	January	February	March	April	May	June	July	August	September	October	November	December	Grand Total
1	36.53	40.33	17.78	28.17	40.05	7.50	38.28	41.85	25.90	35.44	41.36	48.09	34.86
2	33.53	43.35	22.40	25.56		8.32	22.29	54.78	24.06	21.84	47.00	56.64	36.21
3	34.91	33.59	12.95	17.87	29.69	25.33	34.30		28.47	27.92	35.11	44.11	30.16
4	26.48	39.65	27.19	25.80	21.13	25.79	28.09		33.50	17.93			28.63
5	30.63	30.76	20.35	17.04	31.83	20.02	55.41	83.43	24.37	19.32	30.88	44.11	28.68
6	34.86	45.10	29.34	29.98	30.72	23.42	70.72	82.38	23.22	30.01	26.80	56.27	34.55
7	32.76	33.90	29.84	28.18	26.65	24.59	77.18	61.03	21.66	31.14	37.86	37.98	32.57
8	33.27	42.63	31.19	32.25	38.12	33.02	32.83	72.19	24.16	22.07	38.53	46.14	35.33
9	37.45	61.92	44.81	34.36	38.37	36.71	44.69	68.39	33.04	34.04	45.79	50.59	43.76
10	42.64	65.72	39.34	38.08	37.97	33.67	45.34	56.81	36.81	39.00	47.52	56.77	45.56
11	41.41	52.71	46.95	41.00	39.20	35.27	55.21	43.35	38.26	43.14	49.40	54.19	45.67
12	41.70	52.51	47.73	39.64	43.33	33.93	39.45	45.49	31.98	39.68	50.11	54.23	42.97
13	40.04	66.42	44.90	39.05	45.46	29.78	49.86	37.03	29.94	37.69	44.55	50.32	42.05
14	37.13	77.57	54.92	41.76	43.47	26.52	41.74	33.85	33.69	36.71	46.26	54.75	41.93
15	30.04	57.37	54.87	43.19	44.96	27.36	39.44	52.77	30.69	35.27	47.41	56.03	42.92
16	33.81	65.50	45.67	35.78	37.70	32.29	34.79	32.62	27.29	32.27	51.45	59.41	39.02
17	32.61	54.57	42.98	40.41	35.92	25.61	24.36	29.31	29.09	29.91	35.42	47.62	34.11
18	31.66	33.32	33.37	29.73	33.34	26.85	21.95	32.24	26.83	28.10	36.08	47.03	32.22
19	35.10	35.11	28.39	27.40	29.55	22.51	22.24	32.26	26.84	30.69	37.39	44.55	31.33
20	29.19	35.53	28.48	27.66	25.19	19.75	19.91	25.71	24.92	29.37	27.49	41.49	27.77
21	25.73	33.53	25.62	24.89	24.38	19.99	21.86	30.55	21.93	25.98	29.42	39.33	26.42
22	27.34	38.31	16.49	18.40	22.65	20.22	20.80	47.71	13.54	24.82	30.42	41.88	25.94
23	30.17	27.38	20.02	24.34	31.60	19.86	18.17	23.32	0.34	25.69	32.49	45.95	28.36
24	33.46	25.77	22.41	29.51	41.24	17.62	42.46	62.54	32.29	27.20	30.15	51.77	35.05
Gra..	33.75	42.81	33.20	29.67	31.08	25.41	31.16	37.48	27.53	30.42	37.77	47.31	33.95

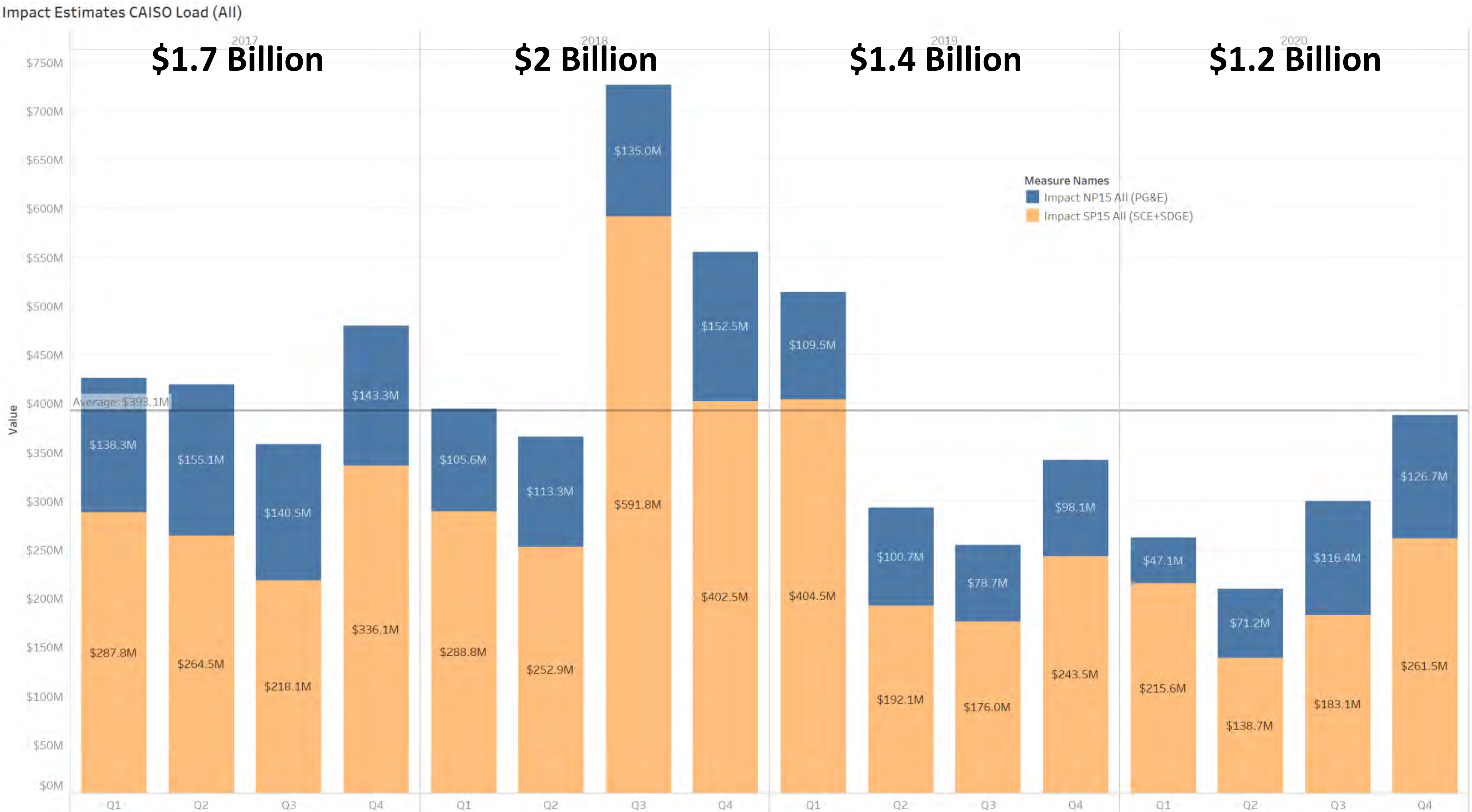
LMP Delta Hub New All SP15: All Hours

HE x	January	February	March	April	May	June	July	August	September	October	November	December	Grand Total
1	0.88	1.78	0.72	1.64	1.61	0.06	0.31	0.67	1.08	1.71	1.72	2.71	1.24
2	1.62	1.15	0.54	0.85	0.00	0.07	0.18	0.88	1.40	0.35	1.96	3.20	1.02
3	1.41	1.49	0.11	0.15	0.72	1.27	0.28	0.00	0.95	0.23	0.59	0.36	0.62
4	0.64	1.05	0.22	0.43	0.51	0.86	1.81	0.00	1.68	0.14	0.00	0.00	0.61
5	0.99	0.82	2.13	2.84	2.82	1.33	4.02	2.69	1.83	1.87	0.77	1.07	1.94
6	0.84	9.58	17.03	18.24	10.40	4.10	11.41	7.97	3.48	13.31	2.90	2.27	8.47
7	9.51	18.00	22.62	17.14	7.95	5.33	8.09	6.89	6.14	20.09	18.30	6.74	12.20
8	16.36	26.41	18.87	13.17	8.91	5.78	2.91	6.99	5.84	9.08	13.48	17.12	12.00
9	15.40	23.56	16.62	7.73	8.97	7.95	3.96	7.17	6.61	9.61	12.59	17.13	11.38
10	14.44	22.68	9.83	6.98	8.27	8.14	5.48	9.62	8.28	7.86	13.07	14.19	10.67
11	10.69	15.86	10.22	6.15	6.96	6.17	7.12	3.15	5.10	5.57	11.53	11.80	8.31
12	7.40	7.43	10.78	4.62	6.99	6.22	5.41	3.67	6.66	6.08	8.77	7.87	6.82
13	8.72	8.23	10.14	7.16	5.50	4.96	9.25	4.18	5.99	6.99	6.31	6.49	6.99
14	6.29	6.86	12.85	7.31	5.96	5.75	8.75	6.55	8.14	6.81	5.40	8.39	7.43
15	3.63	5.08	11.51	6.48	7.61	5.70	10.50	12.77	6.14	5.97	9.09	8.58	7.78
16	4.91	8.69	7.73	4.47	4.26	4.84	9.54	8.68	6.37	7.55	8.15	9.10	7.02
17	7.10	12.07	8.32	6.73	5.21	4.91	8.64	13.00	12.60	19.54	24.50	15.36	11.49
18	25.79	20.64	18.03	12.88	8.60	9.85	13.45	22.10	19.00	21.76	32.47	37.17	20.16
19	29.73	30.45	24.27	21.01	19.78	13.88	15.78	21.85	21.25	27.48	33.34	34.85	24.45
20	21.65	28.30	26.64	24.21	21.33	13.49	13.97	19.49	18.49	21.55	19.01	25.43	21.10
21	11.21	19.59	18.39	20.53	19.27	12.66	11.11	15.77	7.31	9.85	8.82	14.59	14.07
22	3.75	12.21	4.52	6.44	10.23	4.89	3.02	6.54	0.45	3.20	4.06	5.07	5.33
23	1.46	2.42	1.29	1.62	4.08	1.32	1.17	0.94	0.00	1.24	3.52	4.45	1.96
24	1.08	0.91	1.26	2.21	1.00	0.29	1.37	2.52	0.54	0.22	2.01	2.09	1.30
Gra..	8.56	11.89	10.62	8.38	7.37	5.41	6.56	7.67	6.47	8.67	10.10	10.67	8.52

- Left-hand matrix shows only those hours when the marginal cost of a peaker exceeds the LMP. It is the additional $ per MWh that would result in only those hours.
- The right-hand matrix takes the same money expressed in the left-hand matrix and divides that money across all hours of the year.
- Shading ties to MWh in each cell. Cells with darker shading have more MWh.

High Level Cost Savings Estimate for CAISO Load

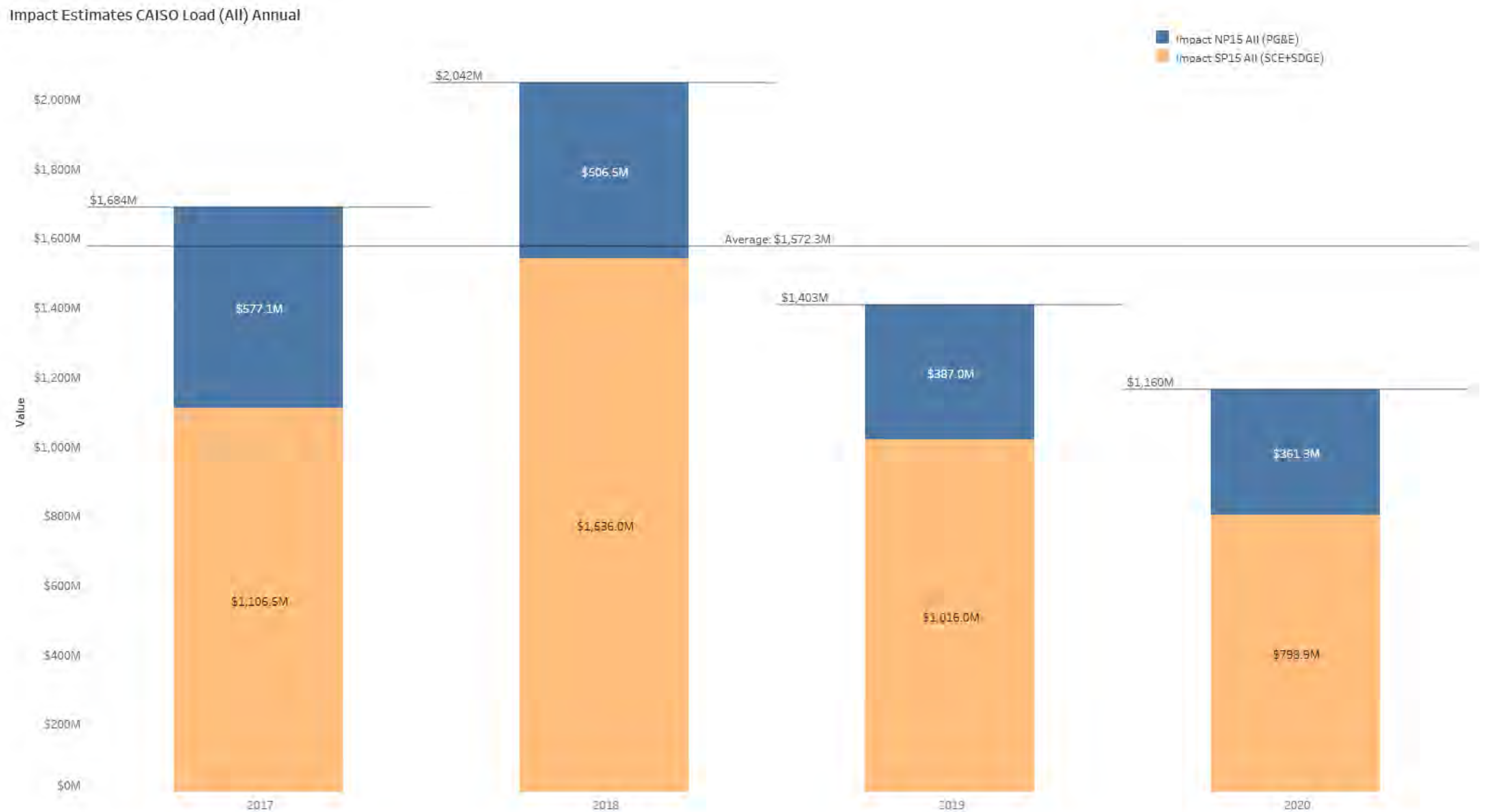
Cost = (Hourly LMP Impact) x (Hourly Regional Load)



- Cost estimates based on hourly load x hourly LMP impact.
- Greater impact Q3 2018 through Q1 2019 driven by SoCal Gas price spikes.
- From Q2 2019 through Q4 2020 averaging about $1.2 billion per year.

High Level Cost Savings Estimate for CAISO Load

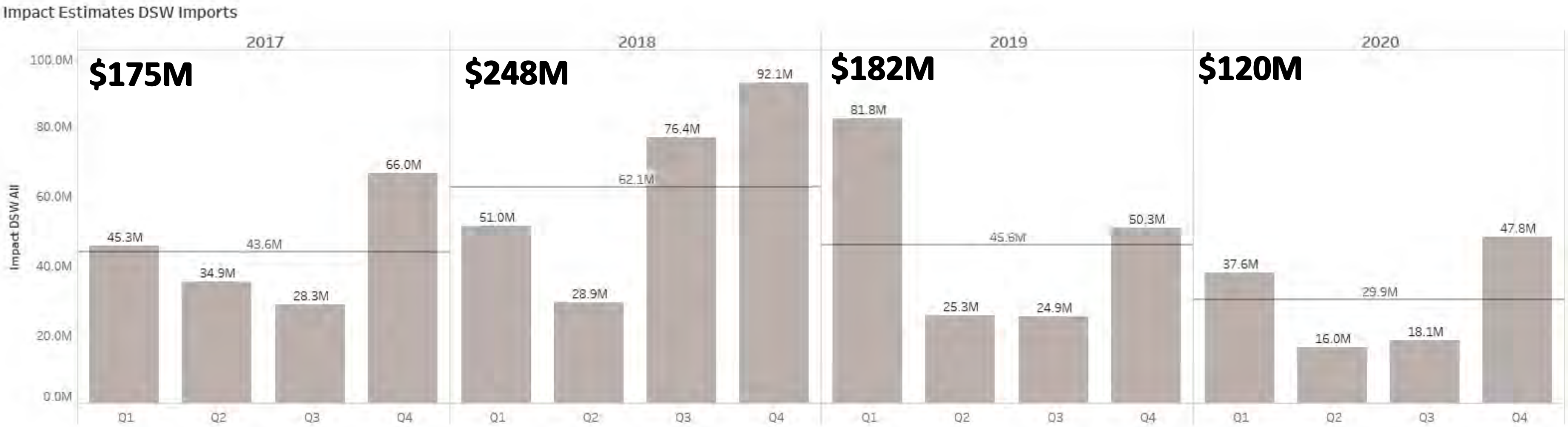
Cost = (Hourly LMP Impact) x (Hourly Regional Load)

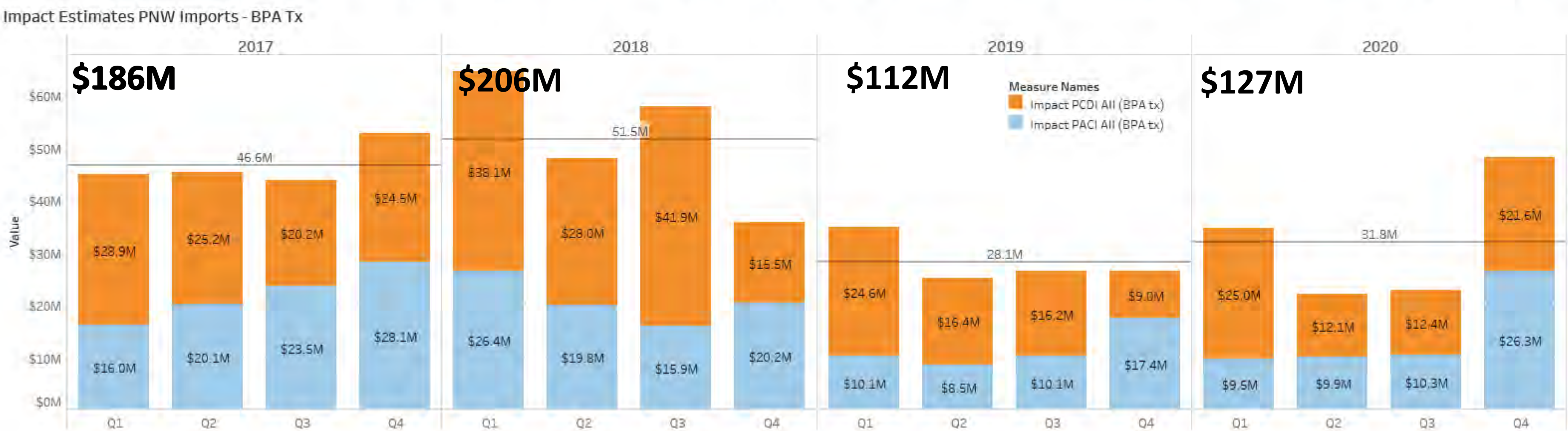


- Same data is previous slide, aggregated annually rather than quarterly.

High Level Cost Impact for Imports to California

Cost = (Hourly LMP Impact) x (Hourly Regional Imports)





- DSW Imports reflect data for imports to California from NV and AZ.
- PNW Imports reflect data for imports to California at COB (blue) and NOB (orange).
- Simplified estimate applying delta price in CAISO (NP15 or SP15) to tie line flows. While not a precise estimate due to potential congestion rent collected by California, it provides an estimate of the magnitude of the impact.

2020 PNW Hydro Generation by Hour
2020 PNW Delta Hydro Generation by Hour

Average hourly production by hour and month of the year for 2020 (close to a normal hydro year as measured by January to July unregulated runoff at The Dalles):

PNW Hydro MWh by Hour 2020

HE x	January	February	March	April	May	June	July	August	September	October	November	December
1	11,291	14,808	9,319	9,143	16,606	18,299	14,827	10,312	7,599	7,568	10,882	11,201
2	10,897	14,684	9,108	8,838	16,427	18,131	14,533	9,978	7,164	7,297	10,695	10,917
3	10,867	14,632	9,053	8,748	16,348	18,027	14,397	9,761	6,997	7,212	10,621	10,883
4	11,098	14,822	9,271	8,931	16,420	18,011	14,354	9,680	6,960	7,224	10,627	11,043
5	11,684	15,428	9,960	9,481	16,690	18,204	14,415	9,769	7,051	7,428	10,834	11,601
6	12,948	16,365	11,769	10,696	17,238	18,419	14,631	10,111	7,545	8,299	11,939	12,851
7	14,481	17,275	13,207	11,437	17,695	18,413	14,845	10,912	8,783	9,830	13,243	14,329
8	15,127	17,599	13,867	11,603	17,766	18,782	15,057	11,260	9,290	10,319	13,702	14,819
9	15,069	17,290	13,539	11,418	17,734	19,104	15,350	11,567	9,336	10,118	13,608	14,503
10	14,838	16,647	12,658	11,066	17,929	19,350	15,682	11,918	9,479	10,026	13,444	13,911
11	14,429	15,995	11,919	10,781	17,954	19,438	16,015	12,373	9,678	9,974	13,258	13,475
12	14,011	15,431	11,476	10,614	18,009	19,521	16,311	12,909	9,945	9,912	13,006	13,059
13	13,710	15,154	11,003	10,350	17,952	19,581	16,710	13,364	10,403	9,805	12,768	12,742
14	13,563	14,837	10,589	10,066	17,963	19,529	16,870	13,707	10,701	9,760	12,578	12,456
15	13,557	14,728	10,379	9,805	17,979	19,497	16,951	14,037	11,035	9,829	12,588	12,557
16	14,143	15,111	10,357	9,689	18,010	19,521	17,056	14,179	11,374	10,049	13,273	13,907
17	15,105	16,208	10,874	9,885	18,287	19,611	17,264	14,534	12,107	10,654	14,240	15,175
18	15,839	17,119	11,796	10,738	18,675	19,848	17,501	14,709	12,537	11,433	15,023	15,849
19	15,912	17,575	12,766	11,554	18,986	19,918	17,580	14,655	12,549	11,863	14,983	15,733
20	15,574	17,560	13,208	11,812	18,953	19,818	17,455	14,283	12,273	11,741	14,669	15,323
21	15,028	17,293	13,071	11,796	18,702	19,591	17,148	13,845	11,564	11,027	14,178	14,833
22	14,274	16,690	12,371	11,286	18,342	19,435	16,602	13,194	10,517	10,257	13,515	14,101
23	13,080	15,816	11,039	10,503	17,512	18,989	15,804	11,710	8,999	9,079	12,174	12,720
24	12,118	15,200	10,014	9,747	17,067	18,703	15,205	10,925	8,202	8,249	11,520	11,908
Grand ..	13,693	16,011	11,362	10,416	17,718	19,073	15,940	12,237	9,670	9,540	12,807	13,329

Average hourly production for the relevant month less average production for that month. A positive value indicates production for that hour exceeds the monthly average:

PNW Hydro Delta MWh from Monthly Avg by Hour 2020

HE x	January	February	March	April	May	June	July	August	September	October	November	December
1	-2,403	-1,203	-2,043	-1,273	-1,113	-773	-1,113	-1,925	-2,071	-1,972	-1,925	-2,128
2	-2,796	-1,328	-2,254	-1,578	-1,291	-941	-1,407	-2,259	-2,506	-2,243	-2,112	-2,412
3	-2,827	-1,379	-2,309	-1,669	-1,370	-1,046	-1,543	-2,477	-2,673	-2,327	-2,186	-2,446
4	-2,595	-1,189	-2,091	-1,485	-1,299	-1,062	-1,587	-2,557	-2,711	-2,316	-2,180	-2,286
5	-2,009	-583	-1,402	-936	-1,029	-868	-1,525	-2,468	-2,620	-2,112	-1,973	-1,729
6	-745	354	407	280	-480	-654	-1,309	-2,126	-2,125	-1,240	-868	-478
7	787	1,264	1,845	1,021	-24	-659	-1,095	-1,325	-888	290	436	1,000
8	1,434	1,588	2,506	1,187	48	-290	-883	-977	-380	779	895	1,490
9	1,376	1,279	2,177	1,002	15	31	-590	-671	-334	579	802	1,174
10	1,145	636	1,296	650	211	278	-258	-319	-192	486	637	582
11	736	-16	557	365	236	365	74	136	8	434	451	146
12	318	-580	114	197	291	448	371	672	275	373	199	-270
13	17	-857	-359	-67	233	508	770	1,127	733	265	-38	-587
14	-130	-1,174	-773	-350	245	457	930	1,470	1,031	220	-229	-873
15	-136	-1,283	-983	-611	260	425	1,010	1,799	1,364	290	-219	-772
16	449	-900	-1,005	-727	291	448	1,116	1,942	1,703	509	466	577
17	1,411	196	-488	-531	568	538	1,324	2,297	2,437	1,114	1,433	1,846
18	2,146	1,108	434	322	956	776	1,561	2,472	2,866	1,893	2,216	2,520
19	2,219	1,564	1,404	1,138	1,267	846	1,640	2,418	2,879	2,323	2,176	2,404
20	1,881	1,549	1,846	1,396	1,235	745	1,515	2,046	2,603	2,201	1,862	1,994
21	1,334	1,282	1,709	1,380	983	519	1,208	1,608	1,894	1,488	1,371	1,504
22	580	679	1,009	870	624	362	662	957	846	718	709	772
23	-614	-195	-323	87	-207	-83	-136	-527	-672	-460	-633	-609
24	-1,576	-811	-1,348	-669	-651	-369	-735	-1,312	-1,468	-1,291	-1,287	-1,421

Key takeaways:

- The PNW hydro system has storage and flexibility that allows it to ramp up and down in a manner that is similar to peakers.
- Exports from PNW to CAISO and the DSW are displacing peakers in other regions.
- Lack of fast start pricing results in compensation that fails to accurately reflect full value hydro provides

Note: Hydro data is from EnergyGPS' 60-dam data set which encompasses 92% of the installed hydro capacity in the US portion of the Columbia River basin.

Conclusions

- Peakers are dispatched frequently in the CAISO and the DSW.
- The volume of peaker dispatches in the WECC is material in terms of number of units dispatched, number of hours dispatched, and MWh dispatched.
- CAISO's policy to exclude fast start costs from the calculation of LMPs suppresses LMPs in all regions and deprives other generators providing similar or superior services of revenue.
  - Cost savings for CAISO load in range of **$1.2 to $2 billion per year**
  - Reduced revenue for CAISO imports from DSW in range of **$120 million to $240 million** per year.
  - Reduced revenue for CAISO imports from PNW in range of **$110 million to $200 million** per year.
- The adoption of standard FERC policy related to fast start costs could impact prices in the following ways:
  - Higher prices during morning and evening ramp hours.
  - Higher prices during hours when PNW hydro increases production.
  - Higher prices in CAISO. Likely higher in DSW and PNW.
  - Higher congestion rents for transmission between PNW and CAISO.

ENERGYGPS LLC

Technical Appendix

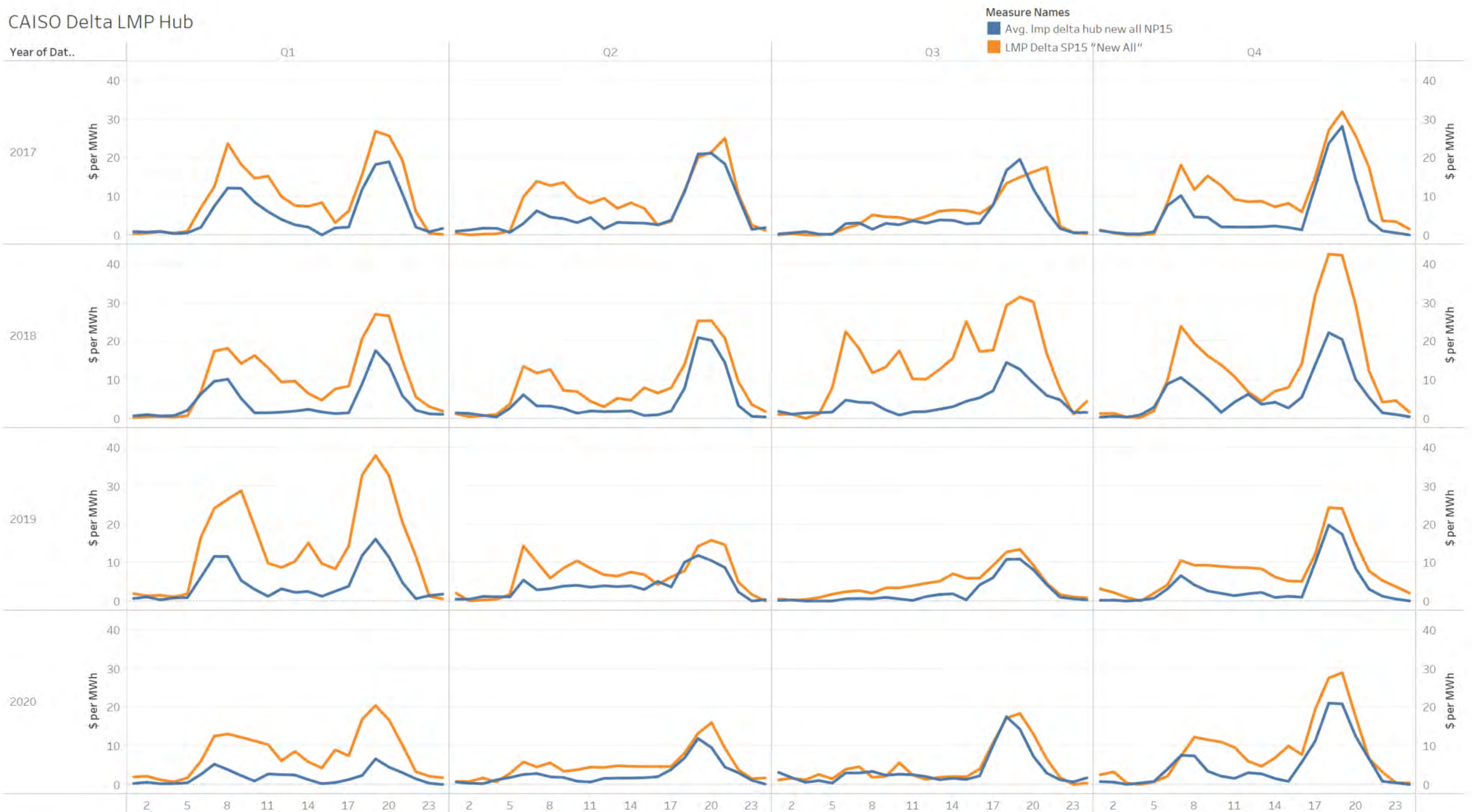
Relative Impact on LMPs
Impact of “First Hour” compared to “All Hours”

	Comparison of "First Hour" versus "Any Hour" Impact on LMPs				
		2017	2018	2019	2020	All
NP15	**Total LMP Impact Across All Hours**	**$5.13**	**$4.62**	**$3.61**	**$3.29**	**$4.16**
	% of Value if Peaker Sets Price During Startup Hour	63%	65%	69%	67%	66%
	Additional Value if Peaker Sets Price Any Hour	37%	35%	31%	33%	34%
SP15	**Total LMP Impact Across All Hours**	**$8.34**	**$11.15**	**$8.20**	**$6.37**	**$8.52**
	% of Value if Peaker Sets Price During Startup Hour	63%	65%	69%	70%	66%
	Additional Value if Peaker Sets Price Any Hour	37%	35%	31%	30%	34%
DSW	**Total LMP Impact Across All Hours**	**$3.02**	**$1.13**	**$0.38**	**$0.77**	**$1.32**
	% of Value if Peaker Sets Price During Startup Hour	55%	54%	47%	57%	55%
	Additional Value if Peaker Sets Price Any Hour	45%	46%	53%	43%	45%
PNW	**Total LMP Impact Across All Hours**	**$2.00**	**$1.83**	**$0.66**	**$0.62**	**$1.28**
	% of Value if Peaker Sets Price During Startup Hour	64%	63%	58%	58%	62%
	Additional Value if Peaker Sets Price Any Hour	37%	37%	42%	42%	38%

- Note: Each region is calculated separately. There are no estimates of inter-regional impacts in this table.
- There are two elements of FERC policy that CAISO does not adhere to: (1) exclusion of unit commitment costs (startup costs) from the LMP and (2) exclusion of units operating at economic minimum from calculation of the LMP.
- This table parses these two impacts. The total impact is reflected by the top, bolded line for each market.
  - “% of Value if Peaker Sets Price During Startup Hour” shows the proportion of total attributable to Unit Commitment.
  - “Additional Value if Peaker Sets Price Any Hour” shows additional impact of exclusion of units at economic minimum.
- Both of these policy choices have a material impact on LMPs.

DSW Data subject to revision; conclusions unchanged.

Impact on CAISO Hub Prices by Year/Quarter/Hour

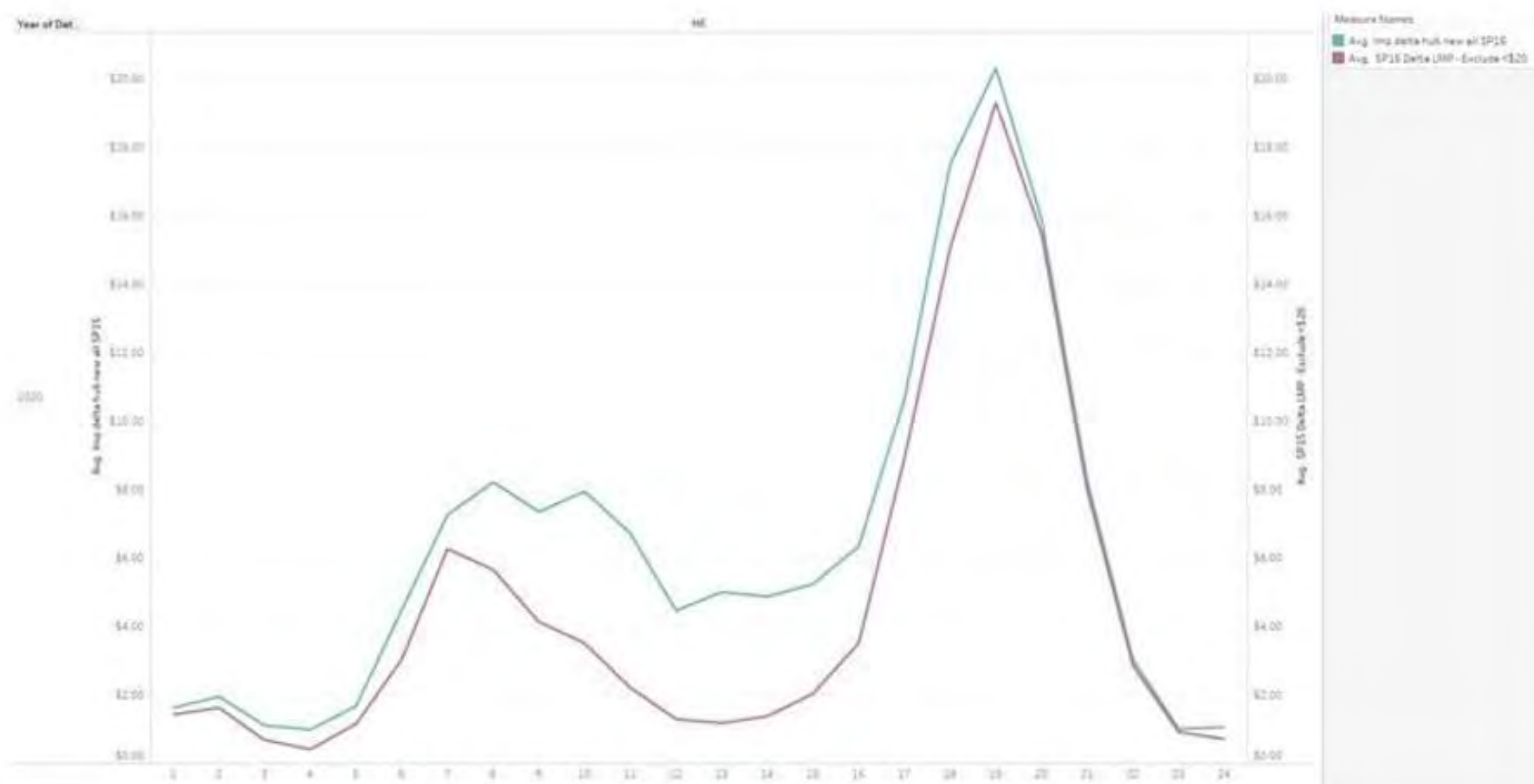


Note: these results show the LMP impact when peaker costs exceed LMP. The results are illustrative but not weighted by record counts. For example, the Q2 impacts are much smaller than the Q3 impacts if weighted by the number of times it occurs.

ENERGYGPS LLC

Further Refinements Can Improve Quality of Analysis

Average SP15 LMP Delta With and Without $20 Threshold Applied



- Challenge to understand which peaker dispatches are for reliability versus economic reasons.
- Bottom line shows results for SP15 where peaker dispatches during hours with low LMPs (middle of the day) and the potential for solar curtailment are excluded.
- Top line shows results as presented in this deck.
- Impact is meaningful but does not change overall conclusions.

Methodology

- Data:
  - Hourly unit-level dispatch data from EPA. Includes MMBtu consumption, MWh production, and emissions data for every unit in the United States.
  - Price and Cost Data: LMPs (CAISO), daily natural gas (ICE), allowed VOM (CAISO), natural gas transport (various).
  - Market Volume Data: PNW hydro (EGPS/USACE), transmission flows (BPA, CAISO), load (various BA’s).

- Methodology:
  - Study foot print: PNW (OR, WA, ID, MT), NP15, SP15, DSW (AZ, NV, NM, UT, WY)
  - Define a fast-start as a dispatch which lasts four hours or less. Identify instances in the EPA data where fast-starts occur.
  - Units eligible to set price during the first hour of dispatch.
  - For each dispatch, calculate first-hour marginal cost.
  - Within each market region for each hour, take the highest marginal cost of all units eligible to set price in that hour. (LMP Proxy)
  - Compare the LMP Proxy for that hour to the actual hub LMP. “LMP New” is the greater of LMP Proxy or the actual LMP in that hour.
  - Delta LMP = LMP New less actual hub LMP for that hour.

The Data

- EPA Air Markets Program Data (AMPD)
  https://ampd.epa.gov/ampd/
  - Date/Time Stamped, Hourly Data for all thermal electricity generators in the USA.
  - Meta Data such as Facility Name, Unit ID, State, Prime Mover, etc.
  - Flow data for each hour including MWh, MMBtu, CO_2 emissions.

- Market data including:
  - Real-time, 5-minute, LMP's for nodes and hubs (aggregated hourly).
  - Natural gas price data.
  - Natural gas LDC delivery cost data.
  - Demand and transmission flows.

- Meta Data
  - Maps each facility to: LMP, state, region, market, LDC.
  - Maps each facility to a natural

ENERGYGPS LLC

Analytical Process

1. Regional Analysis:
   a) Assign facilities to one of four regions based on state and balancing authority.
   b) Estimate startup costs and LMP impacts for facilities within a region.
   c) Identify a market hub for each region: SP15, NP15, AZPS, PACW from CAISO EIM data.

2. Estimate marginal cost for each unit for each dispatch: inputs include:
   a) EPA Data: MMBtu, tons of CO2, MWh of production.
   b) Market Data: Natural gas price for relevant hub, carbon price where relevant.
   c) Meta Data: LDC cost, VOM

3. Convert marginal cost calculations into unit-specific per MWh cost outputs
   a) Sum all marginal costs for that unit from #2 above.
   b) Divide marginal costs per unit by the MWh of production for the unit.

4. If a unit within each market meets the following criteria, it will be the marginal, price-setting unit for that region and that hour:
   a) The unit is in its “startup hour.”
   b) The unit has the highest per MWh marginal cost of all units in in a “startup hour” for that hour.
   c) The unit’s marginal cost is greater than the hub LMP for that hour.

5. Calculate market impact by comparing the estimated LMP of the marginal unit (from #4 above) to the hub LMP for that hour. That difference is the market impact.

ENERGYGPS LLC

Startup Cost per MWh Detailed View

How to determine if a unit can set price:

- Units can only set price when they are eligible to be "marginal." Under certain circumstances a unit cannot be marginal once it is going. For example, this occurs if pmin = pmax and the unit can only be turned off but not down.
- To simplify and be conservative (that is, make sure that no ineligible units are included in analysis), assume that unit can only set price during the hour of startup.

How to determine the Startup Hour:

- Define "Startup Hour" as the first and second hour of operation. For many units, the first hour of operation is a partial hour. Sometimes a small fraction of an hour. Some units have natural gas consumption and no MWh during the first hour. Or very few MWh relative to natural gas consumption.

How to determine Startup Hour Marginal Cost per MWh which is call LMP StartUp or "LMP_SU":

- Startup Hour cost per MWh = total natural gas, carbon, and VOM costs for first two hours of dispatch divided by the total MWh during the first two hours of dispatch. This is defined as "LMP_Startup".
- LMP Startup: Calculated for each hour for a unit eligible to set price.

How to convert LMP StartUp for each unit into a single, marginal cost for that market for that hour:

- LMP Proxy: Calculated for each hour within a given market (e.g., NP15), the maximum LMP Startup across all units for that hour.

How to calculate LMP New for each market for each hour:

- LMP Hub: The LMP for the relevant hub for the relevant hour as published by CAISO.
- LMP New: The higher of LMP Proxy or LMP Hub.

How to calculate market impact --- or Delta LMP – in each hour:

- LMP Delta Hub: The difference between LMP Hub and LMP New
- LMP Delta Node Marginal: The difference between the nodal LMP for the marginal generator and LMP New. Has the exact same number of records as LMP Delta Hub. (will explain these later)
- LMP Delta Node Marginal+: Same as Delta Node Marginal but excludes hours when the LMP Delta Node Marginal is negative (that is, when LMP Proxy < LMP Node). This record count is less than LMP Delta Hub. (will explain these later)

Helpful Book-Keeping Items

"Is Marginal" Flag

- This is a binary value of 0 or 1 for each unit for each hour.
- This flag is set to 1 in a given hour for only the unit that sets price for that hour.
- There is only one unit with the flag set to 1 in any given hour in each market.
- The Is Marginal flag is only set to 1 if:
  - It is in its Startup Hour.
  - Its Startup LMP becomes LMP New because:
    - Its LMP Startup becomes the LMP Proxy.
    - The LMP Proxy > LMP Hub.
- The flag is useful because it allows us to easily filter on and aggregate based upon the marginal unit.

"First Hour" Flag

- This is a binary value of 0 or 1 for each unit for each hour.
- This flag is set to 1 for a unit if it is the first hour of operation. Note that this is truly the first hour not the "Startup Hour".
- There can be multiple units with this flag set to 1 in any given hour.
- This flag is useful because it allows us to count the number of units starting in a given market.

Issues and Solutions

1. ***The first hour problem:*** Small volumes during first hour. Units can set price when they initially startup. Accordingly, trying to find the first hour of dispatch. EPA data reported hourly. There are many instances when the first hour is clearly a partial hour and sometimes a small fraction of an hour. There are hours with MMBtu's and no MWh's or disproportionate amount of MMBtu's to MWh's. Using a true first hour of dispatch to calculate marginal cost resulted in some exceedingly high marginal costs on small volumes. To address this issue, the startup hour is defined as the first and second hours of dispatch. The programming logic identifies the true first hour. Then the costs and production for the first two hours are aggregated to calculate a marginal cost. The calculated marginal cost is then applied to the second hour of operation which is considered the startup hour. There are two potential biases introduced by this logic: (1) under-estimates startup costs for some starts as they are amortized over two hours instead of one and (2) shifts the startup hour later by an hour in certain circumstances.
2. ***The local constraint problem:*** Startup reflects high cost local constraints rather than market-wide pricing. Startup unit is located in a constrained area, has a relatively high marginal cost, and is being started to address local issue. This occurs when LMP proxy (highest startup cost for a given hour in a given market) is established by a local reliability unit. EGPS has taken two steps to identify and address this issue.
   a) LMP Delta Node versus LMP Delta Hub. LMP Delta Hub takes the difference between the LMP Proxy and LMP Hub for that hour. LMP Delta Node compares the LMP Proxy to the LMP at the node for the unit that set LMP Proxy for that hour. This produces a different "delta" value than the LMP Delta Hub. The LMP Delta Node is usually, but no always, less than the LMP Delta Hub. While it is not certain that the LMP Delta Node would directly impact the hub for each hour, it addresses the issue of large gaps between what may be on the margin at the hub versus the node.
   b) Visual inspection. It is possible to visually inspect the data in a number of ways. First, it is possible to examine the LMP Delta Node for each Facility. It is reasonably clear which Facilities are located in constrained areas and it is easy to see the dispatches. Based on this inspection, it would be possible to exclude one or more Facilities from the data set if they are predominantly solving local constraints. The initial review of the data indicates that this happens, but not often.
   c) Visual inspection of the hours of dispatch. It is also possible to examine which hours of the day a unit is being dispatched. If the dispatches are occurring at night it is possible/likely that these dispatches are for local reliability. There are some, but not a lot, of examples of this. This is an area where more time could be invested.

Challenges and Limitations of Study

- Impossible to perfectly estimate the counterfactual “what would prices have been with startup costs in the LMP”.
  - Did not attempt to re-dispatch the grid with new price signals. Assumed the same dispatch under alternative rules as observed with current rules.
  - Did not attempt to move MWh from lower cost region to higher cost region. Drew circle around each region.
  - Given where peakers sit in the resource stack (at the top) and the large volume of peakers being dispatched in NP15, SP15, and the DSW, these units need to run and they likely will regardless of the pricing regime.
  - One caveat – once a market has a large battery fleet that could displace some of these peakers in certain hours, then the pricing regime (higher prices) would impact the products sold by batteries, when they would dispatch, and how they would manage state of charge. All the more reason to send the full price signal to the wholesale markets.
- While the regional divisions makes it feasible to calculate impacts to LMPs, it makes it harder to understand potential cross-regional impacts.
  - Possible to use inter-regional flows to create ranges of potential impacts.
  - This is an area that could use further study in the future to better understand implications for broader regional dynamics.
- Potential for units running to solve highly localized or specialized reliability needs to pollute the results with out-of-merit dispatch.
  - Performed extensive visual inspection of data in Tableau. Identified several units that may be providing local support. Running calculations with and without those units did not materially change results.
  - Calculated impact on LMP using nodal data in addition to hub data to see if there was a “high node” problem. While there are instances of high nodal prices (with lower hub prices) associated with dispatches from certain peaking units, calculating the market impact using the node rather than the hub did not materially change the results.

Tim Belden
tbelden@energygps.com
503-998-5544