(ZGLOBAL)
Power Engineering & Energy Solutions

THE IMPACT OF INCREASED RENEWABLE ENERGY PRODUCTION ON CALIFORNIA CONSUMERS: CHALLENGE OR OPPORTUNITY?

Prepared by: ZGlobal Inc.
February 2026

INTRODUCTION

California's remarkable renewable boom is reshaping the state and western energy landscape. Nearly 7,000 megawatts (MW) of new clean energy capacity were installed in 2024 alone, making it the largest single-year increase of green power in the state's history. This new figure broke the previous records set in both 2022 and 2023, marking a third consecutive year of unprecedented clean energy growth[1]. Not surprising for the world's fourth-largest economy. In 2025, California added approximately 5,700 MW nameplate capacity.

This rapid pace is good news for the climate, competition and consumers but raises key questions: Can the grid keep up? Is it causing retail rates to rise? Does it present a challenge or an opportunity for electric consumers in California and the West?

Renewable Power: The Debate

There is a growing debate over whether California is overproducing renewable energy, forcing the California Independent System Operator (CAISO) to either curtail renewable generation or export excess electricity to neighboring states at a loss. Critics speculate that the rapid growth in renewable production is driving up consumer[2] retail electricity rates. These skeptics urge state policymakers to reconsider the push toward 100%[3] clean energy, arguing that the goal is either infeasible or prohibitively expensive. The reality, however, is far more complex, and renewables may be receiving disproportionate blame for challenges driven by multiple factors

Reasons for energy imports and exports:

1. During periods of high solar and wind production, especially at midday, California often generates more electricity than its in-state demand. Other times, such as in the evening and summertime, California is short of energy and purchases or imports energy from out of state.
2. Even though there has been a massive buildout of battery storage, California is now one-third of the way to its 2045 goal. Battery storage acts as a critical bridge between clean energy and reliability. By capturing excess solar and wind power when it's plentiful and releasing it when demand peaks, batteries keep the grid stable and make it possible to rely on renewable energy around the clock. California has now gone three years in a row without calling a Flex Alert for voluntary conservation – a testament to building the state's strong battery storage fleet[4]. Some argue that California may still have an excess of clean energy and we are simply giving it away to other states at a loss.
3. To prevent grid overload, the CAISO may export electricity to other states at prices based on supply and demand, meaning the energy price may be positive or negative for both exports and imports of energy, depending on grid and market conditions.

---

[1] https://www.gov.ca.gov/2025/06/04/new-data-shows-california-is-adding-more-clean-energy-capacity-to-the-grid-faster-than-ever-before/

[2] CAISO consumers are loads in PG&E, SCE, SDG&E, Community Choice Aggregators and public power agencies within the CAISO foot-print.

[3] California Senate Bill 100 mandates the State electricity to be sourced from 100% renewables and zero carbon free resources by 2025 with an interim target of 60% by 2030.

[4] https://www.energy.ca.gov/news/2025-11/californias-battery-storage-fleet-continues-record-growth-strengthening-grid

This study seeks to unpack the import and export market dynamics shaping these outcomes during January 1, 2022 - December 31, 2024. The report is aimed at answering these questions and is organized as follows:

- **Part 1 – Gross Energy Imports and Exports Price Analysis**
  Has California sold electricity to neighboring states at lower prices than it has paid to purchase electricity from them? Although data on aggregate gross energy imports and exports into and out of California are publicly available, they are difficult to interpret in their raw form. Disaggregating the volume and cost of energy at each intertie between the CAISO and neighboring Balancing Authorities (BAs) on an hourly basis will allow for a more precise assessment of whether, and when, CAISO is exporting electricity at lower prices than it is importing electricity, as well as the associated costs of these gross imports and exports.

- **Part 2 – Negative Energy Price Impacts of Renewable Excess on In-State Oversupply**
  The rapid increase in solar generation has contributed to periods of in-state electricity oversupply during peak solar production hours, leading to negative energy prices even when battery storage is fully utilized to absorb excess generation. What is the impact of negative energy pricing on gross imports and exports? During these negative price periods, is California effectively paying out-of-state BAs to take electricity off its system, or are other market dynamics at play? More broadly, who ultimately benefits from negative energy pricing?

EXECUTIVE SUMMARY

The analysis conducted by ZGlobal draws on a detailed understanding of California's electricity markets using publicly available CAISO data, disaggregating energy imports and exports at each of the 26 interties between CAISO and neighboring out-of-state balancing authorities (BAs) for every hour from 2022 through 2024. In summary, the average cost of CAISO electricity imports is lower than both the CAISO systemwide average price and the average cost of exports. Although negative pricing occurred in less than 5 percent of all hours, the volume of negatively priced imports was approximately twice that of negatively priced exports. These findings indicate that California is not "giving away" its clean energy; rather, the data suggests the opposite.

Summary of Findings

Conclusion #1: CAISO imported 162 TWh for ~ $10 billion at an average cost of $59/MWh between 2022 and 2024.

a) Over the 2022–2024 period, CAISO imported roughly three times more electricity than it exported. The average annual cost of gross energy imports was also lower than the CAISO systemwide average energy cost, meaning California generally purchased electricity from neighboring BAs at prices below its own average market price. Specifically, California bought out-of-state energy at an average of $59/MWh, approximately 20% lower than the three-year systemwide average of $68/MWh, resulting in an estimated $1.6 billion in avoided energy costs.
b) Notably, the cost of electricity imported into CAISO from neighboring BAs was consistently lower than the cost of electricity exported from CAISO to those same BAs. In other words, when CAISO purchased energy (gross imports), it did so at a lower price than when it sold

energy (gross exports). On average, California bought electricity from out of state at $59/MWh while selling electricity to out-of-state BAs at $82/MWh (including export transmission costs), effectively buying low and selling high.

c) A portion of these imports occurred at negative prices. CAISO data shows 1,334 hours in which imports cleared at negative prices. During these hours, out-of-state generators delivered 5.9 TWh into CAISO and collectively paid $66 million to do so. This was therefore not "free" energy, out-of-state generators were effectively paying CAISO to accept their output.

Conclusion #2: CAISO exported 50TWh for ~ $4 Billion at a cost of 68 $/MWh between 2022 and 2024.

(a) The average annual market cost of gross energy exports was $68/MWh; however, when export transmission charges are included, the average rises to $82/MWh. This export-inclusive cost is higher than the CAISO average systemwide energy cost of $68/MWh.
(b) The $82/MWh average cost of exports (including transmission) is approximately 42% higher than the average cost of imports of $59/MWh. Even when export transmission fees are excluded, the $68/MWh average export price remains higher than the $59/MWh average import price.
(c) A portion of exports occurred at negative market prices. When energy clears at negative prices, entities exporting from CAISO are compensated for taking that energy, but they still pay the CAISO Transmission Access Charge (TAC) regardless of whether prices are positive or negative. Over the study period, there were 1,234 hours in which exports cleared at negative prices. During these hours, market participants exported 2.6 TWh and were collectively paid $35 million by CAISO (equivalent to $13.40/MWh). Over the same period, exporting entities paid CAISO $30 million in TAC charges.
(d) CAISO collected a total of $744 million in transmission export revenues over the study period, representing a direct financial benefit to CAISO consumers.
(e) Although not quantified in this report, the fact that export costs are higher than import costs does not necessarily mean that neighboring balancing authorities (BAs) are receiving unfavorable terms. It is economically plausible that purchasing energy from California was still cheaper than producing electricity from their own generation resources, leading them to choose imports from CAISO despite the higher relative export price.

Conclusion #3: By purchasing electricity from neighboring Balancing Authorities (BAs) to displace higher-cost in-area generation, while simultaneously selling electricity to those same BAs at prices above California's marginal production costs, California achieves a favorable overall trade balance.

Observations

1. **Negative pricing:** Negative prices are usually the result of "oversupply" combined with "must-run" generation contractual obligations. Negative energy pricing has benefited CAISO consumers in three ways:
    a) First, the overabundance of energy during solar hours coincides with periods when CAISO load is low (typically during spring months), driving wholesale costs of electricity down so that the cost of the commodity to consumers is reduced. Suppliers are changing the negative price and consumers get paid to use the negative priced energy.

b) Second, the negative prices encourage entities to purchase energy from the CAISO market and sell to the BAs, incurring the CAISO TAC of roughly $16/MWh, which is applied to transmission owners' rates that would have otherwise been paid by California consumers.

c) Third, similar to a produce market or Christmas tree vendor, inventory must be sized to match expected customer demand. That necessitates over-supply. With produce markets and Christmas tree lots, the excess product is recycled or disposed of at a cost. With energy markets, the excess product is sold at negative prices. However, the supply of renewable and hydro resources that contribute to oversupply during low demand periods is the same supply of resources that are used during higher demand periods, displacing more expensive generation sources. Bottom line: this reduces the overall cost of energy to California consumers.

2. **Energy Imports During Negative Priced Periods:** Out-of-state generators have to pay the CAISO to deliver energy during negative-priced hours. Table 7 shows, over the study period, that the CAISO had 1,334 hours when imports cleared at negative prices. During these hours, out-of-state generators delivered 5.9 TWh into CAISO and collectively paid the CAISO market $66 million to do so at an average price of -$11/MWh. The negative gross import volumes accounted for approximately 2.8% of the total CAISO load.

3. **Energy Exports During Negative Price Periods:** For exports at negative prices, entities that export energy from the CAISO are paid for buying energy at the negative prices, but they pay the CAISO TAC regardless of whether the market price is positive or negative. Table 8 shows, over the study period, 1,234 hours during which exports cleared at negative energy prices. Over this period, market participants exported 2.6 TWh and were collectively paid by the CAISO $35 million or $13.40/MWh for energy. Since the exporting entities were utilizing in-area generation that was paying the CAISO to generate electricity, the net cost would be close to $0 (the generators pay $35 million to generate, and the exporting entity is paid $35 million to buy the energy to export). However, the exporting entity paid CAISO $30 million for the TAC.

4. **Benefits to CAISO Loads:** During negative price periods over the study period, CAISO collected $66 million in payment to take the imported energy, plus $30 million in export TAC costs, resulting in a total payment to CAISO of $96 million.

As shown in Section 3 in the analysis regarding the Price Impacts of Increased Renewable Penetration on Consumers, it is apparent that the single largest increase in retail rates is caused by the exponential increase in the transmission and distribution costs, such as infrastructure improvements to prevent wildfires and building a more resilient grid that is not as vulnerable to wildfires. Customers have shouldered a hefty price for wildfire safety measures. From 2019 through 2023, the California Public Utilities Commission authorized the three largest utilities to collect $27 billion in wildfire prevention and insurance costs from ratepayers, according to a report to the Legislature[5]. The $27 billion investment translates into much higher impact on retail rate over 40 years after a 10 percent return on the undepreciated capital asset ("return on rate base") over the

[5] 2024-sb-695-report.pdf

capital asset life of 40 years. This means that the wildfire-related capital revenue requirement is becoming a more significant proportion of the total revenue requirement in rates over time.

The empirical analysis in this report suggests that negative market energy prices provide a benefit to all consumers as the risk is passed on to the suppliers. There is a debate that suppliers will eventually find a way to pass the cost back to the consumers, however, retail rate is highly driven by Transmission and Distribution costs which account for more than two thirds of the retail residential bill in California IOU service area.

Study Period	Sum of Energy Imports (MWh)	Sum of Energy Exports (MWh)	Sum of Import Energy Cost (LMP*MW)	Sum of Gross Export Energy (LMP*MW)	Import Energy Hourly Average (MW)	Export Energy Hourly Average (MW)	Import Energy per unit cost $/MWh	Export Energy per unit cost $/MWh
Qtr1	16,395,626	2,188,341	$757,542,948	$97,207,222	7,591	1,013	$46	$44
Qtr2	15,700,230	4,004,332	$938,503,226	$247,470,876	7,269	1,854	$60	$62
Qtr3	17,971,179	5,923,211	$1,687,429,973	$649,658,737	8,320	2,742	$94	$110
Qtr4	12,249,584	3,033,206	$1,576,266,728	$456,967,459	5,671	1,404	$129	$151
2022 Total	**62,316,619**	**15,149,090**	**$4,959,742,875**	**$1,451,304,293**	7,114	1,729	$80	$96
Qtr1	10,432,384	2,542,983	$965,779,253	$240,908,997	4,830	1,177	$93	$95
Qtr2	11,525,237	4,058,260	$362,529,868	$149,709,246	5,336	1,879	$31	$37
Qtr3	14,560,163	7,889,780	$912,548,000	$598,569,200	6,741	3,653	$63	$76
Qtr4	10,932,126	3,018,420	$586,755,433	$181,660,921	5,061	1,397	$54	$60
2023 Total	**47,449,910**	**17,509,442**	**$2,827,612,555**	**$1,170,848,365**	5,417	1,999	$60	$67
Qtr1	10,554,875	3,408,666	$432,504,432	$325,110,052	4,887	1,578	$41	$95
Qtr2	12,658,230	4,549,843	$266,492,695	$73,919,762	5,860	2,106	$21	$16
Qtr3	15,797,616	7,202,237	$675,297,443	$359,082,788	7,314	3,334	$43	$50
Qtr4	13,340,460	2,856,296	$529,432,921	$115,203,771	6,176	1,322	$40	$40
2024 Total	**52,351,181**	**18,017,042**	**$1,903,727,491**	**$873,316,373**	5,976	2,057	$36	$48
Grand Total	**162,117,710**	**50,675,574**	**$9,691,082,920**	**$3,495,469,030**				

Table 1- Summary of Results

Study Period	Sum of Energy Imports (MWh)	Sum of Energy Exports (MWh)	Sum of Import Energy Cost (LMP*MW)	Sum of Gross Export Energy (LMP*MW)	Import Energy Hourly Average (MW)	Export Energy Hourly Average (MW)	Import Energy per unit cost $/MWh	Export Energy per unit cost $/MWh
Qtr1	16,395,626	2,188,341	$757,542,948	$97,207,222	7,591	1,013	$46	$44
Qtr2	15,700,230	4,004,332	$938,503,226	$247,470,876	7,269	1,854	$60	$62
Qtr3	17,971,179	5,923,211	$1,687,429,973	$649,658,737	8,320	2,742	$94	$110
Qtr4	12,249,584	3,033,206	$1,576,266,728	$456,967,459	5,671	1,404	$129	$151
2022 Total	**62,316,619**	**15,149,090**	**$4,959,742,875**	**$1,451,304,293**	7,114	1,729	$80	$96
Qtr1	10,432,384	2,542,983	$965,779,253	$240,908,997	4,830	1,177	$93	$95
Qtr2	11,525,237	4,058,260	$362,529,868	$149,709,246	5,336	1,879	$31	$37
Qtr3	14,560,163	7,889,780	$912,548,000	$598,569,200	6,741	3,653	$63	$76
Qtr4	10,932,126	3,018,420	$586,755,433	$181,660,921	5,061	1,397	$54	$60
2023 Total	**47,449,910**	**17,509,442**	**$2,827,612,555**	**$1,170,848,365**	5,417	1,999	$60	$67
Qtr1	10,554,875	3,408,666	$432,504,432	$325,110,052	4,887	1,578	$41	$95
Qtr2	12,658,230	4,549,843	$266,492,695	$73,919,762	5,860	2,106	$21	$16
Qtr3	15,797,616	7,202,237	$675,297,443	$359,082,788	7,314	3,334	$43	$50
Qtr4	13,340,460	2,856,296	$529,432,921	$115,203,771	6,176	1,322	$40	$40
2024 Total	**52,351,181**	**18,017,042**	**$1,903,727,491**	**$873,316,373**	5,976	2,057	$36	$48
Grand Total	**162,117,710**	**50,675,574**	**$9,691,082,920**	**$3,495,469,030**				

Table 2 - Summary of Results

Year	Gross Import Energy per Unit Cost $/MWh	Gross Exports Energy per Unit Cost $/MWh	Gross Exports Energy per Unit Cost plus TAC $/MWh	CAISO Systemwide Cost of Energy $/MWh
2022	$80	$96	$112	$95
2023	$60	$67	$81	$65
2024	$36	$48	$62	$44

Table 3 - Summary CAISO Day-Ahead Market Imports, Exports, and Systemwide Energy Costs (2022–2024)

Year	CAISO Systemwide Cost of Energy $/MWh	CAISO Gross Import: Energy per Unit Cost $/MWh	CAISO Gross Imports (MWh)	Cost of Imports	CAISO System wide average - CAISO Imports	California Savings
2022	$95	$80	62,316,619	$4,985,329,520	$15	$934,749,285
2023	$65	$60	47,449,910	$2,846,994,600	$5	$237,249,550
2024	$44	$36	52,351,181	$1,884,642,516	$8	$418,809,448
Total	**$68**	**$59**	**162,117,710**	**$9,716,966,636**	**$9**	**$1,590,808,283**

Table 4 - Summary CAISO Day-Ahead Market Imports and Systemwide Energy Costs (2022–2024)

Year	CAISO Systemwide Cost of Energy $/MWh	CAISO Gross Export: Energy per Unit Cost $/MWh	Export Transmission Cost $/MWh	Export Cost ($/MWh)	CAISO gross Exports (MWh)	Cost of Exports	CAISO Exports - CAISO System wide Average	California Revenue
2022	$95	$96	$16.38	$112	15,149,090	$1,702,454,734	$17	$263,291,184
2023	$65	$67	$13.5	$81	17,509,442	$1,409,510,081	$16	$271,396,351
2024	$44	$40	$13.99	$54	18,017,042	$972,740,098	$10	$179,990,250
Total	**$68**	**$68**	**$15**	**$82**	**50,675,574**	**$4,170,092,984**	**$14**	**$714,677,785**

Table 5 - Summary CAISO Day-Ahead Market Exports and Systemwide Energy Costs (2022–2024)

Year	CAISO Systemwide Cost of Energy $/MWh	CAISO Gross Import: Energy per Unit Cost $/MWh	Export cost ($/MWh)	% of Export over Imports	% Export over system wide
2022	$95	$80	$112	40%	18%
2023	$65	$60	$81	34%	24%
2024	$44	$36	$54	50%	23%
Total	**$68**	**$59**	**$82**	**42%**	**22%**

Table 6 - Summary Comparison between CAISO Day-Ahead Market for Imports, Exports and Systemwide Energy Costs (2022–2024)

APPENDIX A - DETAILED REPORT

Definition and Data Collection

There are 26 interface transmission paths between CAISO and its neighboring BAs in the western U.S., where energy can either be imported into the CAISO or exported from the CAISO.

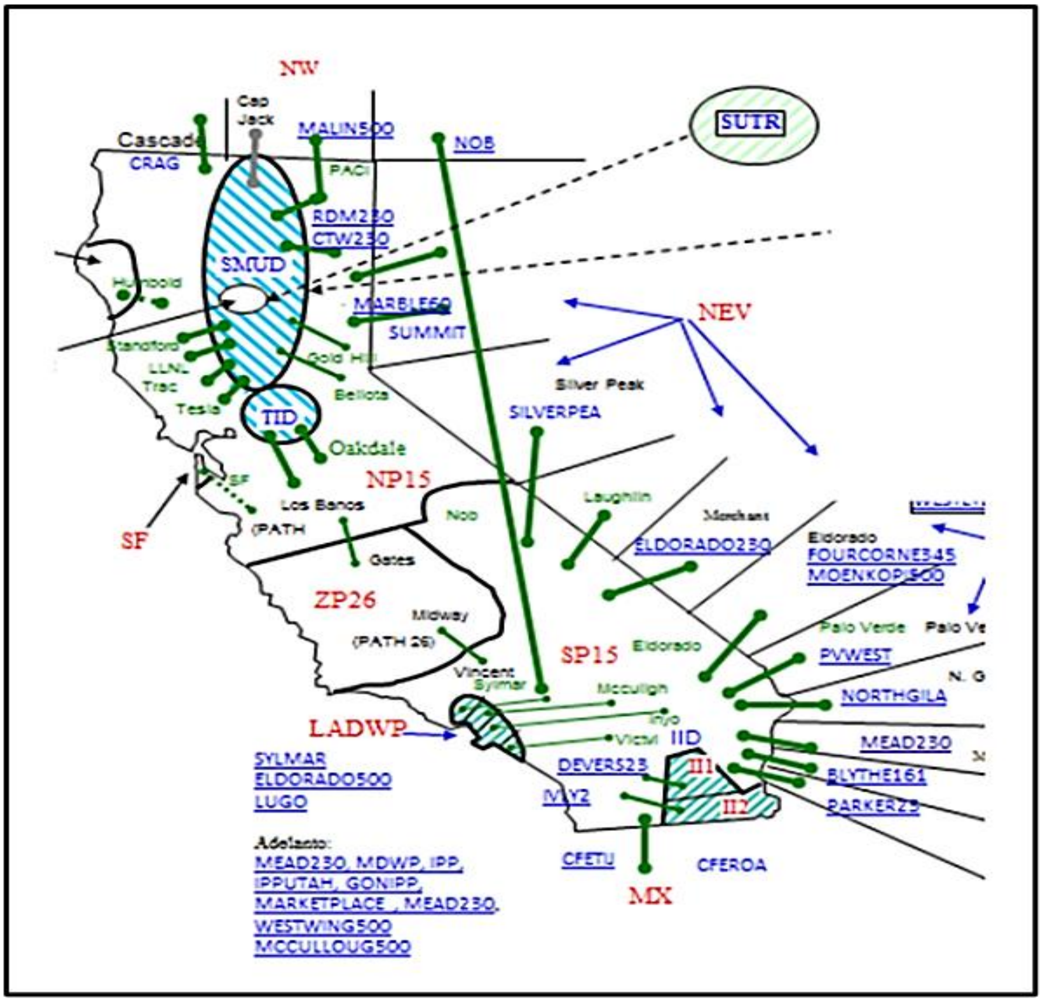


Figure 1 - Interface Paths Between CAISO & Other BAs for Imports and Exports

This analysis used publicly available data from the CAISO OASIS website. For each hour, we downloaded:

- Import and export quantities (MWh).
- Corresponding LMPs (Imports and Exports separately) at all 26 interface points.

Over a one-year period, this resulted in 8,760 hours × 26 interfaces × 2 directions (import/export). The hourly data represented the day-ahead clearing prices at each interface where imports or exports occur. Quarterly volumes were calculated by summing hourly imports and exports separately for each of the 26 interface points.

This analysis used CAISO's published day-ahead[6] hourly cost of electricity, known as the Locational Marginal Price (LMP)[7]. LMP is calculated at every node in the CAISO footprint and reflects the cost of electricity generation, transmission congestion, and energy losses for loads, generators, imports, and exports. For this report, the "cost of electricity" refers to the wholesale energy cost paid by load-serving entities and excludes retail-level costs such as transmission, distribution, and public benefit charges.

LMP is determined through a nodal pricing method based on actual bids from generators, loads, imports, and exports across the CAISO grid, neighboring utilities, and other market participants. By stacking supply offers from in-state and out-of-state generators against demand bids from loads and exporters, CAISO identifies the clearing price at the intersection of supply and demand. This clearing price, the LMP, represents the marginal cost of serving one additional megawatt-hour at a specific location, accounting for energy costs, congestion, and system losses.

Hundreds of in-state and out-of-state generators participate in the day-ahead market as suppliers, while loads and exporters represent demand. Because CAISO is part of the broader Western Interconnection, any generator in the region can sell into the CAISO market (imports) and any utility outside California can purchase from the CAISO market (exports). Thus, the CAISO day-ahead market ensures efficient pricing across the grid while integrating regional supply and demand.

At the system level, CAISO's total cost of energy is the net wholesale cost to its loads, including in-state generation, imports, and exports. This systemwide cost is viewed as a benchmark to analyze whether CAISO is buying or selling imports and exports above or below the annual average price. For example, if CAISO imports 100 MW and exports 40 MW in a given hour, the net import is 60 MW. If it imports 100 MW but exports 140 MW, the net export is 40 MW.

In summary, LMP reflects the marginal cost of balancing supply and demand under network constraints, while the systemwide cost of energy captures the aggregate net cost of serving CAISO's load. Historically, because California is the largest population center in the Western Interconnection, it has relied on imports—particularly from the Northwest and the Southwest—to help meet peak load requirements.

Section 1. Volume of Imports/Exports from 2022 to 2024

In the day-ahead market, CAISO relied significantly on imports across 2022–2024, though the balance of imports and exports shifted year to year (see Table 1 above).

2022: CAISO imported 62 TWh and exported 15 TWh, resulting in 47 TWh of net imports, about 23% of total load (211 TWh).

[6] CAISO day-ahead market represents 93 percent of the total cost and therefore is a good approximation of the total electricity cost (excluding retail transmission, distribution and other regulatory and public benefits costs). https://www.caiso.com/documents/2023-annual-report-on-market-issues-and-performance.pdf, page 88

[7] https://www.caiso.com/systems-applications/portals-applications/open-access-same-time-information-system-oasis

2023: Imports fell to 47 TWh while exports rose to 17.5 TWh, leaving 29.5 TWh of net imports, about 15% of total load (203 TWh). Compared with 2022, imports declined 24% while exports increased 17%.

2024: Imports increased slightly to 52 TWh, with exports rising to 18 TWh, for 34 TWh of net imports. This represents 16% lower imports and 20% higher exports compared to 2022.

1.1 Per Unit Cost of Imports/Exports, Excluding CAISO TAC to Exports

Below is a summary of the CAISO systemwide cost of energy from 2022 through 2024.

1.1.1 CAISO Day-Ahead Market – 2022:

1. The CAISO systemwide cost of energy was reported at $95/MWh[8]. The total CAISO estimated wholesale energy cost of serving load was about $21.6 billion or $95/MWh for 211 TWh.
2. CAISO market paid about $5 billion for gross imports and collected $1.45 billion for gross exports. The net imports were about $3.55 billion, which is about 16% of the total cost of energy.
3. CAISO market per unit cost for gross imports was $80/MWh and $96/MWh for gross exports.
4. The cost of gross imports is less than the CAISO systemwide energy cost, and revenue from gross exports was higher than the CAISO systemwide cost of energy.
5. In addition, the CAISO market collected $248 million or $16.38/MWh in TAC from gross exporters. This increases the cost of gross exports from $1.45 billion to $1.7 billion for an average of $112/MWh, significantly above the CAISO systemwide cost of energy.

1.1.2 CAISO Day-Ahead Market – 2023:

1. The average total cost of the electricity system-wide was reported at $65/MWh[9]. The total CAISO estimated wholesale cost of serving load in 2023 was about $14.5 billion, for 203 TWh.
2. CAISO paid about $2.8 billion for the gross imports and sold $1.2 billion from the gross exports. The net imports were about $1.6 billion, which is about 11% of the total cost of energy.
3. The average price of gross imported energy was $60/MWh and $67/MWh for gross exports.
4. Similar to 2022, the cost of imports was less than the CAISO systemwide cost of energy, and revenues from exports were higher than the CAISO systemwide cost of energy.
5. In addition, CAISO collected $253 million in transmission fees from exporters. This increases the amount of CAISO revenue from gross exporters from $1.2 billion to $1.4 billion with an average gross export per unit cost of $81/MWh, significantly greater than the CAISO systemwide cost of energy.

1.1.3 CAISO Day-Ahead Market – 2024:

---

[8] www.caiso.com/Documents/Presentation-2022-Annual-Report-on-Market-Issues-and-Performance-Jul-28-2023.pdf, page 3

[9] 2023-annual-report-on-market-issues-and-performance.pdf, page 86

1. The CAISO systemwide cost of energy was reported at $44/MWh[10]. The total CAISO estimated wholesale cost of serving load in 2024 was about $9.1 billion for 207 TWh.
2. CAISO paid about $1.9 billion for the gross imports and collected $0.87 billion from the gross exports.
3. The average price of imported energy was $36/MWh from imports and $48/MWh in exports.
4. Similar to 2023, the cost of imports was less than the CAISO average and revenue from exports was higher than the CAISO average.
5. In addition, CAISO collected $243 million in transmission fees from gross exporters. This increases the gross export revenues from $0.87 billion to $1.1 billion with an average gross export per unit cost of $62/MWh, significantly above the CAISO systemwide cost of energy.

Section 2. Price Impacts of Renewable Excess on In-State Oversupply

California has seen a sharp rise in the number of hours when wholesale energy prices turn negative. This trend is most noticeable in the spring when demand is low, and hydroelectric plants must release water as snow melts. This section explores whether negative pricing is materially significant and who benefits from it. The analysis emphasizes exports, since the interaction between CAISO and neighboring states is central to understanding whether CAISO load ultimately gains or loses from negative prices.

Negative prices reflect deliberate economic choices. Renewable generators, with near-zero marginal costs, often continue producing even when prices are negative, accepting that they are effectively paying to generate. Other generators, however, prefer to shut down or curtail output when prices fall below their bids. For example, if a generator schedules 100 MW at $10/MWh but the market clears below that level, it can self-curtail rather than operate at a loss. While these self-curtailment decisions are outside the scope of this report, they are analyzed in a separate ZGlobal study[11].

Negative pricing is not unique to electricity markets. Consider the Christmas tree market: Before December 25, trees may cost $100 or more. By December 26, many lots will give them away, or even pay customers to haul them off, despite no change in the quality of the trees. The shift in timing changes the market value. Similar patterns occur in food retail, where unsold inventory is written off as a loss. In energy markets, timing is equally critical, especially for intermittent resources like wind and solar that cannot easily adjust their output. Suppliers respond rationally, sometimes choosing to pay to generate rather than shut down. Importantly, the share of renewable output subject to negative prices remains a small fraction of total wholesale electricity sales.

Understanding imports and exports under positive and negative prices is essential. CAISO defines these as follows: Imported energy costs include out-of-state transmission charges, while exports from CAISO to other states always incur CAISO TAC charges, regardless of whether LMPs are positive or negative. Gross positive and negative LMPs and volumes are calculated separately by summing across all 26 scheduling/interface points between CAISO and neighboring states for each

---

[10] https://www.caiso.com/documents/2024-annual-report-on-market-issues-and-performance-aug-07-2025.pdf, page 138

[11] https://zglobal.biz/the-increasing-trend-of-negative-energy-pricing-and-renewable-energy-curtailments-in-california-is-this-a-problem-or-an-expected-outcome-of-a-rationally-functioning-market/

hour. The same method applies to both imports and exports, ensuring a consistent measure of market flows under positive and negative pricing conditions.

2.1 Positive Import LMPs

Generators located outside CAISO that sell energy into the CAISO day-ahead market are paid the positive LMP at the CAISO interface. CAISO, in turn, recovers these costs by charging other day-ahead participants, such as CAISO demand, battery charging, and hydroelectric pumping as well as convergence bids. Importantly, non-CAISO transmission costs are the responsibility of the external generators.

Example: A Montana generator delivering 100 MW to CAISO when the import LMP is $50/MWh will receive:

- Payment from CAISO: 100 MWh × $50/MWh = $5,000
- Transmission charges: 100 MW × (non-CAISO transmission rate), paid to the non-CAISO transmission owner.

The $5,000 CAISO pays to the Montana generator is funded by CAISO market participants, primarily load-serving entities purchasing energy. Thus, positive import LMPs represent a cost to CAISO retail customers.

2.2 Negative Import LMPs

When LMPs are negative, out-of-state generators selling into the CAISO day-ahead market are charged the negative LMP at the CAISO interface. The revenues CAISO collects are redistributed to day-ahead participants purchasing energy at negative prices or selling at positive prices (including CAISO load, storage charging, positive-LMP generators, and convergence bids). As with positive imports, non-CAISO transmission costs remain with the exporting generator.

Example: A Montana generator delivering 100 MW when the import LMP is -$50/MWh will be:

- Charged by CAISO: 100 MWh × -$50/MWh = - $5,000
- Additionally charged non-CAISO transmission costs

The $5,000 collected from the Montana generator is paid out to CAISO market participants buying at negative prices. Thus, negative import LMPs represent revenue to CAISO load serving entities. There are many reasons why a generator would pay to generate, mostly renewables would need to generate to capture other non-CAISO revenues such as revenues from green attributes or carbon credit or simply contractual obligation that force them to generate even at loss.

2.3 Positive Export LMPs

Generators located inside CAISO that sell energy into the day-ahead market for export are paid the positive LMP at their generator node. The exporter (which may or may not be the generator itself) is charged at the CAISO scheduling/interface point LMP. If the generator is also the exporter, they bear congestion and loss costs equal to the difference between their node price and the scheduling point price, plus the CAISO TAC for energy leaving the system.

Example: A Fresno generator exporting 100 MW to Arizona:

- Generator receives: 100 MWh × $50/MWh = $5,000
- Exporter pays: 100 MWh × $52/MWh = - $5,200
- Export TAC: 100 MWh × $15/MWh = - $1,500

Net transaction = $5,000 – $5,200 – $1,500 = - $1,700

With this example, the CAISO load is unaffected since the generator's output serves Arizona demand.

2.4 Negative Export LMPs

For exports at negative LMPs, CAISO generators are charged the negative LMP at their node. The exporter pays (or receives) settlement at the scheduling point LMP, along with CAISO TAC.

Example: A Fresno generator exporting 100 MW when the generator node LMP is -$50/MWh and the scheduling point LMP is -$52/MWh:

- Generator pays: 100 MWh × -$50/MWh = - $5,000
- Exporter receives: 100 MWh × -$52/MWh = $5,200
- TAC charge: 100 MWh × $15/MWh = - $1,500

Net transaction = -$5,000 + $5,200 – $1,500 = - $1,300

This example illustrates how negative export pricing can result in generators paying to produce and export energy while CAISO still collects TAC charges.

2.5 Negative Import LMPs

In Section 1 of this report, gross import costs were presented as a combined total of both positive and negative prices. To better understand the impacts of negative imports, when LMPs fall below $0/MWh, the study separated them from the total and analyzed their effect during the study period (see Tables 7 and 8).

- **Frequency and Volume:** CAISO data shows 1,334 hours when imports cleared at negative prices. During these hours, out-of-state generators delivered 5.9 TWh into CAISO and collectively paid $66 million to do so. This was not simply "free" energy, generators were effectively paying CAISO to accept their output.
- **Scale Relative to Load:** The negative import volumes accounted for approximately 2.8% of total CAISO load, equivalent to serving the demand of over one million Californians. From the perspective of CAISO consumers, this represented a net benefit: CAISO collected $66 million from import generators who chose to pay CAISO in order to continue operating.
- **Rising Trend:** Negative import hours have grown rapidly, from 22 hours in 2022 to 211 hours in 2023, and further to 796 hours in 2024, indicating a clear and accelerating trend.

Period	Number of Hours where Imports <0$/MWh	% of hours	Sum of Imports MWh	Sum of IMPORT LMP ($/MWh*MW)	Average $/MWh
Qtr1	13	1%	91,713	-$237,159	-$3
Qtr2	9	<1%	190,433	-$158,059	-$1
Qtr3	0	0%	0	$0	$0
Qtr4	0	0%	0	$0	$0
2022 Total	**22**	**<1%**	**282,147**	-$395,218	-$1
Qtr1	15	1%	95,720	-$188,649	-$2
Qtr2	187	9%	855,730	-$5,274,215	-$6
Qtr3	0	0%	0	$0	$0
Qtr4	9	<1%	48,238	-$202,666	-$4
2023 Total	**211**	**2%**	**999,688**	-$5,665,530	-$6
Qtr1	247	11%	977,699	-$12,883,243	-$13
Qtr2	527	24%	2,116,572	-$31,424,977	-$15
Qtr3	11	<1%	82,694	-$136,233	-$2
Qtr4	11	<1%	63,596	-$292,258	-$5
2024 Total	**796**	**9%**	**3,240,561**	**-$44,736,711**	-$14
Qtr1	305	14%	1,451,052	-$15,861,500	-$11
2025 Total	**305**	14%	**1,451,052**	-$15,861,500	-$11
Grand Total	**1,334**	**5%**	**5,973,449**	**-$66,658,960**	-$11

Table 7 - Negative Imports into CAISO: Frequency, Volume, & Financial Benefits to California Consumers (2022–2024)

2.6 Negative Export LMPs

Similar to what was described in Section 2.5, the study separated the periods when export LMPs were below $0/MWh and analyzed their specific impact during the study period.

- **Frequency and Volume:** CAISO data shows 1,234 hours during which exports cleared at negative prices. Over this period, market participants exported 2.6 TWh and collectively were paid by the CAISO $35 million to export energy, but also paid the CAISO to generate the energy, resulting in a net cost of $0 (excluding the cost of congestion and losses). However, the exports would also incur the CAISO TAC, resulting in approximately $36.4 million payment to the CAISO. This was not simply free energy for neighboring balancing authorities; California generators themselves paid CAISO the TAC to export their output.
- **Relative Scale:** These negative export volumes represented about 1.2% of the total CAISO load. From the perspective of CAISO consumers, the $35 million collected came directly from in-state generators choosing to pay in order to continue generating for export netted against roughly the same amount paid to entities to export energy results in $0 cost to the CAISO.
- **TAC:** The entities exporting energy incurred approximately $36.4 million in TAC fees. These transmission revenues are largely credited back to CAISO load, reducing overall system costs.
- **Rising Trend:** Negative export hours are increasing sharply, growing from 20 hours in 2022 to 203 hours in 2023 and reaching 783 hours in 2024.

Period	Number of Exports Hours where LMP is <0 $/MWh	% of hours	Sum of Exports MWh	Sum of Exports LMP ($/MWh*MW)	Average $/MWh
Qtr1	13	1%	26,885	-$53,100	-$1.98
Qtr2	7	<1%	52,641	-$61,464	-$1.17
Qtr3	0	0%	0	$0	$0.00
Qtr4	0	0%	0	$0	$0.00
2022 Total	**20**	**<1%**	**79,526**	**-$114,564**	-$1.44
Qtr1	11	1%	22,056	-$56,501	-$2.56
Qtr2	183	8%	307,755	-$2,057,077	-$6.68
Qtr3	0	0%	0	$0	$0.00
Qtr4	9	<1%	12,523	-$134,196	-$10.72
2023 Total	**203**	**2%**	**342,334**	**-$2,247,774**	-$6.57
Qtr1	241	11%	427,451	-$6,546,149	-$15.31
Qtr2	506	23%	1,220,951	-$19,885,065	-$16.29
Qtr3	18	1%	49,157	-$75,622	-$1.54
Qtr4	18	1%	47,576	-$356,889	-$7.50
2024 Total	**783**	**9%**	**1,745,135**	**-$26,863,725**	-$15.39
Qtr1	228	11%	472,741	-$6,145,478	-$13.00
2025 Total	**228**	**11%**	**472,741**	-$6,145,478	-$13.00
Grand Total	**1,234**	**4%**	**2,639,736**	**-$35,371,540**	-$13.40

Table 8 – Negative Exports from CAISO: Frequency, Volume, & Financial Impacts on Generators & Revenues to Consumers (2022–2024)

2.7 Summary of Negative Pricing Impacts

During the study period, and considering negative pricing hours only:

- Out-of-state generators paid $66 million to CAISO load.
- Market participants that exported energy paid approximately $30 million in TAC fees, benefiting CAISO load, and were paid $35 million by the CAISO in the form of negative-priced exports. However, generators that continued to operate during those hours paid the CAISO approximately the same $35 million, resulting in a net energy cost to the CAISO of $0.
- Total Benefit to CAISO load was roughly $96 million.

Although these amounts represent a relatively small share of total system costs, the evidence shows that the CAISO load is not losing money from negative pricing. In fact, the opposite is true:

- California load benefits directly from payments collected.
- Neighboring states gain short-term access to cheap or even free energy, which allows them to conserve capacity.
- That conserved capacity can later flow back into CAISO during non-solar hours, when California's load has the greatest need for imports.

More broadly, negative pricing imports and exports produce a mix of benefits:

- Negative imports primarily benefit CAISO consumers.

- Negative exports primarily benefit out-of-state consumers, while TAC charges from all exports flow back to the CAISO load.

Period	Number of Hours where imports LMPs <0$/MWh	Number of Hours wher Exports LMP is <0 $/MWh
Qtr1. 2022	13	13
Qtr2 2022	9	7
Qtr3,2022	0	0
Qtr4, 2022	0	0
Qtr1,2023	15	11
Qtr2,2023	187	183
Qtr3, 2023	0	0
Qtr4,2024	9	9
Qtr1, 2024	247	241
Qtr2,2024	527	506
Qtr3, 2024	11	18
Qtr4, 2024	11	18
Qtr1, 2025	305	228
Total	1,334	1,234

Table 9 - Number of Hours with Negative Day-Ahead Prices (< $0/MWh) for Imports & Exports in the CAISO Market (2022–Q1 2025)

Appendix D includes additional charts to illustrate import and export price ranges during the study period.

Section 3. Price Impacts of Increased Renewable Penetration on Consumers

While Sections 1 and 2 focused on wholesale market dynamics, imports, exports, and negative pricing, it is equally important to examine how these trends intersect retail electricity bills. Section 3 explores the consumer perspective, asking whether rising renewable penetration has contributed to higher residential rates.

The average annual residential rate in California has more than doubled in the last 10 years, from 0.143 $/kWh to close to 0.30 $/kWh, but this is deceiving because of the multitier rates. So, this analysis is focused on the moderate residential consumption of 755 kWh per month for a typical household and looks at a larger sample of California utilities. It was stunning how difficult it was to gather this information.

The data shows that the latest increases in PG&E's rates indicate that the utility has the highest average monthly residential rate in California, even higher than SDG&E.

Is California's electricity restructuring the cause for PG&E retail rates to double? The simple answer is a resounding no. In fact, restructuring of the wholesale energy market, which is only one component of the residential bill, mainly the energy line item, has decreased. The remaining components of residential electricity costs that were not restructured have skyrocketed.

Rate increases are disproportionate among California utilities for a variety of reasons. As an example, the Imperial Irrigation District (IID), a public power utility, has the lowest rates in California.

This is despite being in the desert of Southern California, where there is no hydro generation and extremely hot weather, but very low risks of fires. IID should be given a lot of credit for keeping rates low, but this disproportionality across the utilities, regardless of why, is worth exploring.

A typical residential electric bill comprises two components:

1. Energy
2. Delivery Charges (transmission, distribution, other delivery charges)
3. For example, in 2025, the typical E-1 residential customer in El Dorado Hills, California, with a monthly usage of 613 kWh would see the following bill breakdown from PG&E: the energy charge is $0.1377 per kWh [12] (This makes up roughly 41% of the retail rate). In the past, it used to be much higher. Delivery charge of 0.288 per kWh for a total of $0.445 /kWh.

For instance, in 2022, the typical E-1 residential customer in El Dorado Hills[13], CA bill breakdown from PG&E for a monthly usage of 613 kWh[14] is: Energy $0.157/kWh, representing roughly 41% of the total retail rate. (Historically, this energy component had been significantly higher.) The delivery charge is $0.288 per kWh, bringing the total retail rate to approximately $0.445 per kWh.

In 2014, a typical E-1 residential customer in El Dorado Hills, California, with a monthly usage of 690 kWh[15] would have seen the following bill breakdown from PG&E: the energy charge was $0.150 per kWh, representing roughly 41% of the total retail rate. (Historically, this energy component had been significantly higher.) The delivery charge was $0.198 per kWh, resulting in a total retail rate of approximately $0.356 per kWh.

The good news is that the energy cost, adjusted for inflation, and components decreased due to competition, but the bad news is that transmission and distribution (T&D) or delivery costs have tripled or quadrupled, and not because of renewables, but rather wildfire resiliency and upgrade of aging T&D infrastructure.

Table 10 summarizes residential E-1 energy and delivery cost and the relative increase or decrease since 2014.

Year	Pioneer Energy Rate ($/KWh)	PG&E Delivery Cost ($/KWh)	Pioneer Energy Cost Changes from 2014	PG&E Delivery Cost Changes from 2014	Total Rate ($/KWh)
2014	0.150	0.198	0.00%	0.00%	0.348
2022	0.157	0.288	4.46%	45.45%	0.445
2025	0.137	0.298	-9.49%	50.51%	0.435

Table 10 - Sample Residential E-1 Retail Rate

12 https://pioneercommunityenergy.org/wp-content/uploads/2025/02/Pioneer-March-2025-Residential-Rate-Sheet.pdf.

13 Placer and El Dorado County are in PG&E service area, and the energy is mostly served by Pioneer Community Choice Aggregator under Assembly Bill 117 (2002). Placer and El Dorado Counties is where most of ZGlobal staff live and work.

14 https://www.pge.com/assets/pge/docs/account/alternate-energy-providers/pio-rcc.pdf.

15 http://inedc.com/22/wp-content/uploads/2022/06/pio_rateclasscomparison.pdf

2024 CPUC Senate Bill 695 provides a forecast of the bundled residential average rate (Energy, T&D and other charges showings below[16]:

Bundled Residential Average Rate	Year-End				
	2023 Actual	2024	2025	2026	2027
PG&E Nominal Rate	$ 0.322	$ 0.371	$ 0.400	$ 0.435	$ 0.460
SCE Nominal Rate	$ 0.305	$ 0.305	$ 0.344	$ 0.365	$ 0.385
SDG&E Nominal Rate	$ 0.404	$ 0.404	$ 0.432	$ 0.462	$ 0.494

Table 11 - Forecasted Average Retail Rate

Some may argue that transmission cost increases were the result of renewable energy project development, while the increase in distribution costs is a result of climate change and wildfire prevention, in particular. Whatever the reasons, T&D costs remain regulated and monopolized, and the costs keep going up.

The observations from this study do not see the trend abating, and the prediction is that California has not come close to hitting the ceiling on these costs. Perhaps the focus needs to be on a different approach to lowering utility bills or, at least, preventing these open-ended increases.

Is it time to open transmission and distribution to the competition?

[16] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/office-of-governmental-affairs-division/reports/2024/2024-sb-695-report.pdf#page=56
Table 11, Page 66

APPENDIX B - TRANSMISSION CHARGES

Balancing Authorities and Market Structure in the West

Historically, local utilities owned, maintained, and operated their entire electric systems, including generation, to serve their customers. Over time, independent (non-utility) generators were also allowed to sell energy into organized and bilateral markets. Federal rules, overseen by the North American Electric Reliability Council (NERC), require utilities to balance supply (both utility-owned and independent generation) and load every minute. This responsibility falls to the Balancing Authority (BA), which ensures that electricity supply and demand within its geographic footprint are always balanced. Maintaining this balance is critical. If supply falls short of demand, system frequency drops below stable levels, risking serious equipment damage and widespread blackouts.

There are approximately 37 BAs in the western U.S., most of which are directly or indirectly interconnected. Together, they manage:

- ~156,000 miles of transmission lines
- ~170,000 MW of capacity
- Service to ~90 million people

BAs also buy and sell energy among themselves as supply and demand fluctuate across regions. The western interconnection spans Alberta and British Columbia in Canada, Baja California Norte in Mexico, and 14 U.S. Western states.

CAISO's Role in California: Within this footprint, CAISO is unique. It is the only organized wholesale market in the West and serves about 80% of California's load. Unlike utilities, CAISO is not-for-profit and owns no generation or transmission assets, it strictly operates the market and maintains reliability of the grid. By contrast, many other BAs in the West are vertically integrated utilities that own, operate, buy and sell power while managing reliability obligations.

California has eight BAs, listed below:

1. BANC – Balancing Authority of Northern California
2. CAISO – California Independent System Operator
3. IID – Imperial Irrigation District
4. LADWP – Los Angeles Department of Water & Power
5. PacWest – PacifiCorp West
6. NV Energy – Nevada Energy
7. TID – Turlock Irrigation District
8. WALC – Western Area Lower Colorado

CAISO serves as BA for PG&E, SCE, and SDG&E and several cities in Southern California, which own generation and transmission but are not balancing authorities. There are also five municipal utilities that are participating transmission owners within the CAISO. All of their transactions must go through CAISO.

IID and TID function as both utilities and BAs. They own transmission and generation assets, serve defined geographic territories, and transacted energy independently.

Other Western BAs are primarily utilities that handle both operations and market interactions for their own service areas.

Economic Dispatch: BAs act as grid operators, dispatching generation to maintain reliability at the lowest cost. Because each generator has different operating costs, resources are dispatched starting with the least costly, subject to system constraints and reliability requirements.

- Traditional utility BAs perform economic dispatch internally.
- ISOs/RTOs, like CAISO, use bid-based markets where buyers and sellers submit offers, and energy is cleared based using LMP.

Dispatch Process: Day-Ahead Commitment: BAs determine which generators should be online for each hour of the following day. They factor in load forecasts, unit operating limits, ramp rates, and minimum run times. Forecasting uses weather data, past consumption, behavioral patterns, and economic activity.

Real-Time Dispatch: BAs adjust committed resources in real time to match actual load and grid conditions. Automatic generation control (AGC) fine-tunes output to maintain frequency, balancing demand, generation, and interchange (imports/exports).

Because all Western BAs are interconnected, transactions can cross state lines. For example, a generator in New Mexico can sell power anywhere in the western interconnection, provided transmission capacity is secured across the relevant BAs.

Year	Annual total energy (GWh)	Average load (MW)	% change	Annual peak load (MW)	% change
2019	214,955	24,541	-3.9%	44,301	-11.6%
2020	211,919	24,128	-1.7%	47,121	6.4%
2021	211,020	24,092	-0.1%	43,982	-6.7%
2022	210,879	24,059	-0.1%	52,061	6.4%
2023	203,268	23,207	-3.5%	44,534	-14.5%

Table 12 - Annual System Load in CAISO 2018 to 2023

LMP Composition: The electricity cost for imports is one of the components that California consumers pay in their monthly electricity bill, which is associated with imports. Transmission payments paid by exports in the form of TAC are credited to the consumers. LMP or nodal pricing ensures efficient energy delivery by reflecting the true cost of providing electricity at different locations within the electric grid and at the interface's node. CAISO calculates over 3,000 LMPs' price nodes within the CAISO footprint and 26 LMPs' prices at the interface each hour in the day-ahead market. These prices between locations vary depending on the demand or loads /consumption of electricity based on the availability of transmission capacity in a specific interface between the BA and at each of the approximatley 3,000 nodes within the CAISO footprint. Since power prices fluctuate with supply and demand, LMP ensures that electricity is priced efficiently, taking into account local consumer demand and energy supply costs.

The LMP consists of three components:

1. Energy (System Marginal Energy Cost): Cost to produce the next marginal MWh. Uniform across nodes if there is no congestion.

2. Congestion: Additional cost when transmission bottlenecks require dispatching higher-cost local generation.
3. Losses: Costs associated with line losses; marginal losses increase with distance from generation.

At each node:

- Generators receive the same nodal LMP regardless of their bid, incentivizing truthful marginal-cost bidding.
- Loads pay the nodal LMP at their withdrawal point.
- CAISO, as a central clearinghouse, collects loads and pays generators.

The LMP is established by stacking supply offers and demand bids, applying transmission constraints and losses, and determining the market-clearing price at each node. Appendix C provides simplified numerical examples of how locational marginal pricing and congestion can result in negative pricing outcomes.

TAC: Energy exported from CAISO is subject to the TAC, approved by FERC.

- 2022: $16.38/MWh – exporters paid ≈ $248 million
- 2023: $14.45/MWh – exporters paid ≈ $253 million
- 2024: $13.50/MWh – exporters paid ≈ $253 million
- 2025: $13.99/MWh – exporters paid ≈ $45 million in Q1 alone

Over the full study period, CAISO collected approximately $790 million in TAC fees, in addition to energy costs.

Quarter	CAISO TAC $/MWh	CAISO Transmission Costs to Exporters
Q1 2022	$16.38	$35,845,033
Q2 2022	$16.38	$65,590,952
Q3 2022	$16.38	$97,022,188
Q4 2022	$16.38	$49,683,916
Total	**2022**	**$248,142,089**
Q1 2023	$14.45	$36,746,100
Q2 2023	$14.45	$58,641,857
Q3 2023	$14.45	$114,007,315
Q4 2023	$14.45	$43,616,166
Total	**2023**	**$253,011,439**
Q1 2024	$13.50	$46,016,991
Q2 2024	$13.50	$61,422,885
Q3 2024	$13.50	$97,230,200
Q4 2024	$13.50	$38,559,996
Total	**2024**	**$243,230,072**
Q1 2025	$13.99	$45,275,040
	Total	**$789,658,639**

Table 13 - CAISO Transmission Costs Paid by Exporters

Imports do not pay the TAC. The electricity price or LMP associated with imports includes transmission costs paid by the generators to non-California transmission owners that are selling electricity to CAISO.

APPENDIX C – ILLUSTRATIVE EXAMPLES OF LMP AND CONGESTION PRICES

Example 1: Basic Supply and Demand Clearing Prices with no Transmission Constraints

Generation bids are as follows:

1. G1 = 500MW bid at $30/MWh at Node A. This generator is in Oregon and sells into CAISO as an import. The $30/MWh bid means G1 is only willing to sell energy if the market-clearing price is $30/MWh or higher.
2. **G2 = 500 MW bid at $50/MWh at Node B**.
   This generator is located within CAISO and sells in the CAISO market. The $50/MWh bid means G2 is only willing to sell energy if the market-clearing price is $50/MWh or higher.
3. **G3 = 80 MW Self-Scheduled (price taker) at Node C.**
   This generator is located within CAISO and sells in the CAISO market. As a price taker, G3 is willing to accept whatever price the market clears.
4. **Load = 500 MW at Node C.**
   The load is a price taker, meaning it is willing to pay the market-clearing price to purchase energy from G1, G2, and G3.

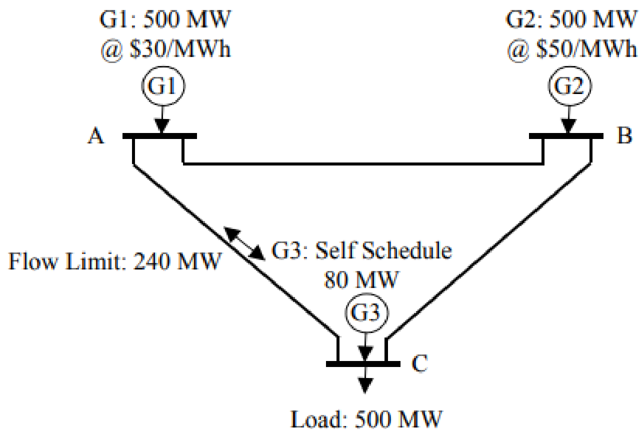


Figure 2 - Example 1 – Basic Supply and Demand Clearing Prices Without Transmission Constraints, Showing Uniform LMPs Across Nodes A, B, & C

Assume No Flow Limit of 240 MW from Node A to C:

The load at node C is 500 MW and is self-scheduled (price taker). The three transmission lines are assumed to have no losses and have identical impedances. Note that for every MW generated from G1 to serve the load, 2/3 MW will flow online A-C, whereas for every MW generated from G2 to serve the load, 1/3 MW will flow on that line. These fractions (2/3 and 1/3) state how much power will flow on a path in each direction because of the injection of 1 MW at one node and withdrawal at another. These fractions are called the Power Transfer Distribution Factors (PTDFs) or shift factors. The shift factor for node C is 0 because there is no change in the flow on any path if 1 MW is injected and withdrawn at node C.

The least cost solution to meet the 500 MW load at C would have been to generate 420 MW from G1 and 80 MW from G3. G1 is the marginal unit, and any additional generation needed to supply 1 MW of additional load can be served by G1 since G1 has another (500-420 MW) available supply or 80 MW. The energy clearing price would be 30$/MWh set by G1.

In this case, congestion is zero, ignoring losses, LMP at nodes A, B, and C are equal to 30$/MWh + 0 $/MWh + 0$/MWh = 30 $/MWh.

Here are the results:

- The energy as their price is 50$/MWh, which is above for G1,
- G3 is paid 80 MW x 30$/MWh = $2,400.
- Total payment to supplier G1 is 420 MW x 30 $/MWh = $12,600.
- G2 did not provide any = $12,600 + 0 + $2,400 = $15,000.
- Load is charged 500 MW x 30$/MWh = $15,000.
- A to C flow = 420 MW x 2/3 = 281 MW.
- A to B to C flow = 420 MW x 1/3 = 139 MW.
- Total flow from A-C is 281 MW + A to B to C flow 139 MW = 420 MW = G1
- The sum of the supplier's payment is equal to the sum of load charges with no congestion.

Example 2: Assume Transmission Constraint or Flow Limit of 240 MW from Node A to C:

The grid is much complicated. Assume a transmission limit between node A and C with a limit of 240 MW, meaning, for grid reliability, the maximum flow from Node A to C should not exceed 240 MW, and, in the previous dispatch, 281 MW was flowing from node A to C, which is not acceptable.

To ensure the flow on the A-C line does not exceed the 240 MW limit, the least cost solution is to schedule G1 at 300 MW and G2 at 120 MW. The flow on the A-C line will then be 2/3 x 300 MW + 1/3 x 120 MW = 240 MW. Note that the CAISO must reduce the cheaper energy from G1 and buy energy from more expensive sources of energy from G2, resulting in higher prices.

The LMPs resulting from this "optimal" solution are $30/MWh at node A, $50/MWh at node B, and $70/MWh at node C. This is because the LMP at each node is the cost of serving an increment of load at that node. The cost of serving one more MW of load at node A is $30, and at node B is $50. Regarding node C, note that to serve one more MW of load at node C from either G1 or G2 would increase the flow online A-C and violate the 240 MW flow limit.

The least cost way to serve one more MW of load at node C without violating the transmission constraint online A-C would be to increase G2 by 2 MW and reduce G1 by 1 MW. This will result in a net of 1 MW (to serve the increment of load), with a net effect of -1 MW x (2/3) + 2 MW x (1/3) = 0 MW on the flow on the A-C line The net cost to serve the incremental MW of load at node C is thus (2 MW x 50 $/MWh) – (1 MW x 30 $/MWh)= 70 $/MWh. The LMP at node C is therefore 70$/MWh, which is higher than the bid prices from both G1 and G2

- G1 receives a payment of 300 MW x 30 $/MWh = $9,000
- G2 receives a payment of 120 MW x 50 $/MWh = $6,000
- G3 receives a payment of 80 MW x 70 $/MWh = $5,600
- Total payment to generators 1,2, and 3 = $20,600
- Load at node C will pay 500 MW x 70$/MWh = $35,000

The net collection by CAISO of ($35,000 - $9,000 - $6,000 - $5,600) = $14,400. This collection is exactly equal to the congestion rent associated with the constraint on the A-C line. The shadow price of the A-C line constraint is $60/MWh, as shown above. The congestion rent associated with the A-C line is thus 60 $/MWh x 240 MW = $14,400, which equals the net amount collected by the CAISO.

More explanation: There was one binding transmission constraint (line A-C) with a shadow price[17] of 3 MW x (50 $/MWh - 30 $/MWh) = 60$/MWh. This is the value of the shadow price because an increase of 1 MW in the transmission capacity of line A-C (or relaxation of the constraint by 1 MW) would allow for the substitution of 3 MW of the more expensive G2 generation (50$/MWh) with 3 MW from the less expensive G1 generation (30$/MWh). With node C as the slack bus, the Marginal Congestion Cost components (MCC) of the LMPs are thus 0$/MWh at C.

At node A, the MCC is: - 2/3 x 60 $/MWh = - 40$/MWh.

At node B, -1/3 x 60 $/MWh = -$20/MWh.

The MCC component may be positive or negative depending on whether incremental power consumption at the relevant node marginally increases or decreases the congestion on the congested path(s).

Because the LMP at node C is 70$/MWh, the system Marginal Energy Cost Component (MEC) is 70$/MWh for all nodes. The Marginal Loss Cost components (MLC) are 0 $/MWh, because losses were ignored in Example 1. Note that the sum of the three components at each node equals the LMP at that node:

Node A: LMP = 70 $/MWh - 40 $/MWh + 0 $/MWh = 30 $/MWh.

Node B: LMP = 70 $/MWh - 20 $/MWh + 0 $/MWh =50 $/MWh.

Node C: LMP = 70 $/MWh + 0 $/MWh + 0 $/MWh = 70 $/MWh

G3 benefited the most as it received the highest per-unit revenue.

Example 3: This example shows that suppliers could be charged rather than get paid for supplying energy due to congestion.

Consider a three-node, three-transmission-line network, with Generation at nodes A, B, and C, and a load at node C. Generation capacities and bids are:

1. G1 = 360 MW Self-Scheduled (price taker) at node A,
2. G2 = 100 MW Bid at 10 $/MWh at node B
3. G3 = 100 MW Bid at 50 $/MWh at node C.
4. The load at node C is 420 MW and is self-scheduled (price taker).

The three transmission lines are assumed to operate without losses and have identical impedances. Line A-C has a transmission limit of 240 MW.

[17] Shadow prices can represent the cost of congestion in transmission lines. the shadow price reflects the marginal cost of congestion or the value of relaxing the congestion limit.

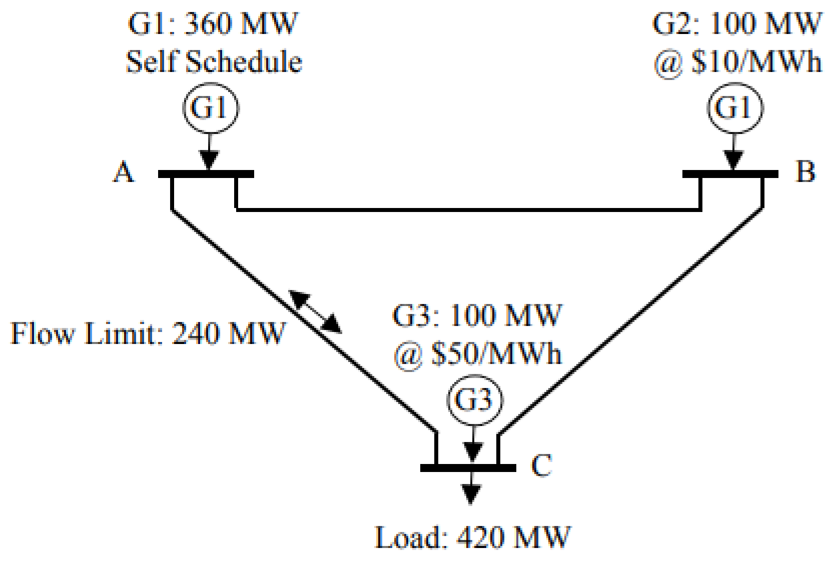


Figure 3 - Example 3 – Three-Node Network with a 240 MW Transmission Constraint on Line A–C, Illustrating Negative LMP at Node A & the Creation of Congestion Rents

The self-scheduled generation of 360 MW at G1 results in the flow of 360 x 2/3 = 240 MW on the A-C line. Thus, the only way to serve the load (which may include battery charging) at node C is to generate 60 MW from G3. The cheaper supply of 10 $/MWh at node B cannot be used. The LMP at each node is the cost of serving an increment of load at that node. The LMP at node B is 10 $/MWh, and the LMP at node C is 50$ /MWh. Regarding node A, 1 MW load at node A would reduce G1 generation at A by 1 MW, and the flow on line A-C by 1 x 2/3 = 2/3 MW, allowing 2 MW of generation from the cheaper G2 generation (because an increase of 2 MW from G2 would result in 2 x 1/3 = 2/3 flow on the A-C line filling the space created by the 1 MW Load at node A). This allows serving the incremental load of 1 MW at node A and replacing 1 MW of the more expensive G3 generation with the cheaper G2 generation.

The net cost of serving 1 MW of load at node A is thus (2MW x 10 $/MWh) – (1 MW x 50 $/MWh) = -30 $/MWh. The LMP at A is thus -$30/MWh.

In this example:

- G1 will be charged 30 $/MWh x 360 MW = $10,800 rather than receiving a payment.
- G3 receives a payment of 50 $/MWh x 60 MW = $3,000.
- The load is charged 50 $/MWh x 420 MW = $21,000.

This example results in a net collection by the CAISO of ($21,000 + $10,800 – $3,000) = $28,800. This collection is exactly equal to the congestion rent associated with the constraint on the A-C line. The shadow price of the A-C constraint is $120/MWh, because a 1 MW increase in the A-C limit allows for the displacement of 3 MW of G3 generation by 3 MW of the cheaper G2 generation, with an associated cost reduction of (50 $/MWh x 3 MW) – (10 $/MWh x 3MW) = 120 $/MW. The congestion rent associated with line A-C is thus 120 $/MWh x 240 MW = $28,800, which equals the net amount collected by the CAISO.

Example 4: Generation and Load in CAISO with Imports and Exports

Consider a two-node, single-line network with generation sources G1 at node 1 and G2 at node 2. The system includes an export equal to 5% of the load at node 1, while the remaining 95% of the load is located at node 2.

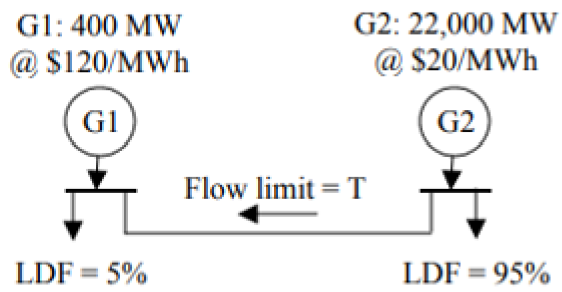


Figure 4 - Example 4 – Two-Node Network with Transmission Constraint (T), Showing Bids from G1 and G2 and Load Distribution Factors (LDF) Across Nodes

1. G1 generation from Washington at node 1 is offering to sell energy to CAISO 400 MW, and its bid price is 120 $/MWh.
2. G2 generation is within the CAISO of 22,000 MW at node 2, at a bid price of 20 $/MWh.
3. Export (load 1) at node 1 wishes to buy 950 MW and is willing to pay CAISO 50 $/MWh to export the energy from CAISO to Arizona.
4. CAISO load 2 (which could include battery charging) at node 2 is 19,000 MW and is willing to pay 50 $/MWh.

The transmission line between nodes 1 and 2 is assumed to be lossless for simplicity but has a transmission limit of T <= 700 MW in either direction.

Case 1: The transmission limit is 700 MW. In this case, not all 950 MW of export load can be served from the cheaper G2 generator without violating the transmission limit. The distributed load at node 1 is 0.05x 19,000MW = 950MW, and the distributed load at node 2 is 0.95*20,000MW = 19,000MW.

Due to the transmission constraint, only 700 MW of load at node 1 can be served from G2, and the remaining 250 MW must come from the higher cost G1 generation source. Thus, G1 is scheduled at 250MW and G2 at 19,700 MW.

- The resulting LMPs are LMP1=120 $/MWh and LMP2 = 20 $/MWh.
- G1 receives a payment of 250 MW x 120 $/MWh = $30,000.
- G2 receives a payment of 19,700 MW x 20$/MWh = $394,000.
- Export (load 1) is charged 950 MW x 120 $/MWh =$114,000.
- Load 2 is charged 19,000 MW x 20 $/MWh = $380,000.

The result is a net collection by the CAISO of ($380,000 + $114,000 – $30,000 – 394,000) = $70,000 This collection is exactly equal to the congestion rent associated with the constraint on line between nodes 1 and 2. the shadow price of the congestion constraint is (120 $/MWh - 20 $/MWh) = 100$/MWh resulting in a congestion rent of 100 $/MWh x 700MW = $70,000.

Case 2: The transmission limit is 550MW.

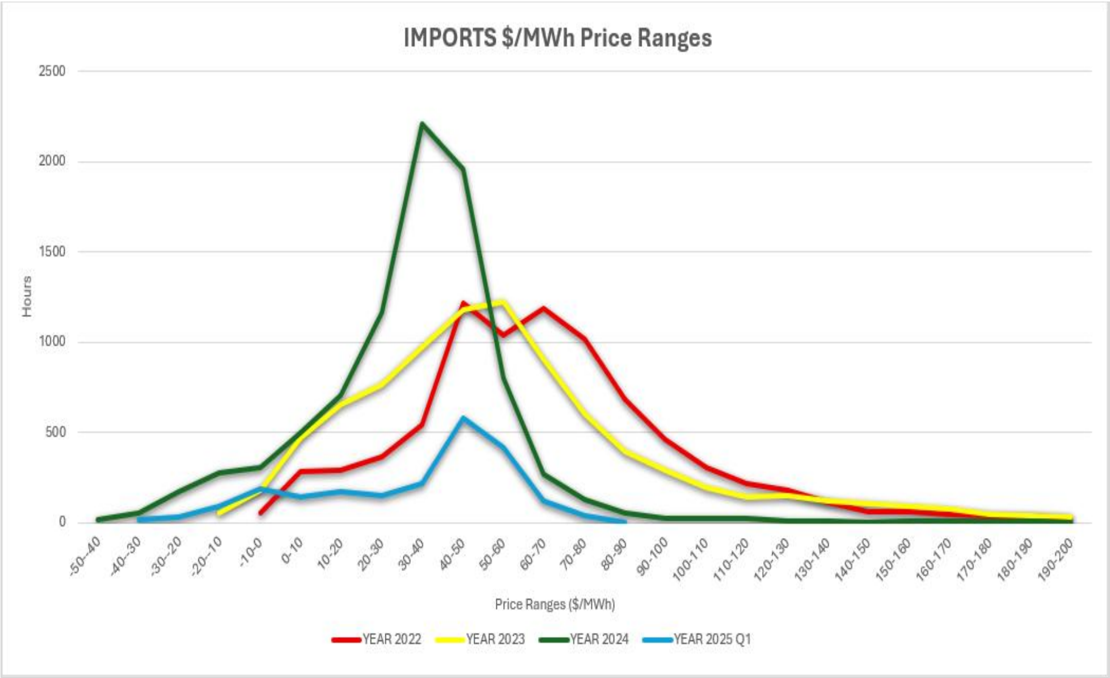
Since the maximum generation from G1 is 400MW, in this case, only (550MW+ 400MW) = 950 MW of export load at node 1 can be served at any price without violating the transmission constraint. Because the export load at node 1 is 5% of the total load, the load served at any price is thus 950MW/0.05 = 19,000 MW.

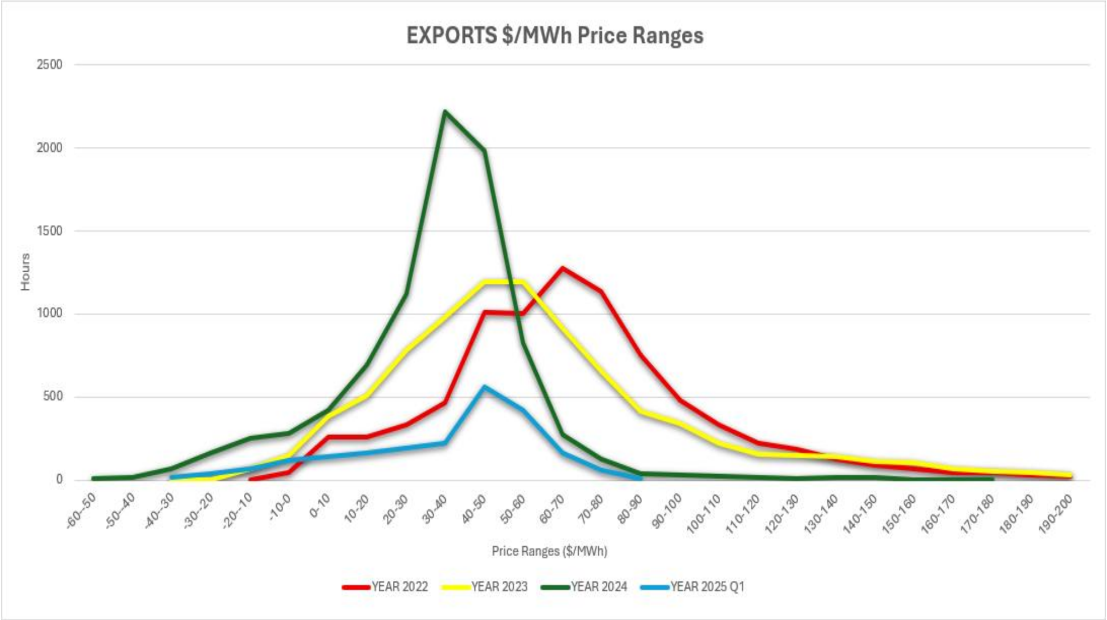
To compute the LMP1, the shadow price of the transmission constraint must be calculated. An increase of 1 MW in the transmission constraint would allow 1 more MW of load at node 1, and thus 20 more MW of load 2 to be served. Since the load 1 and 2 values are energy at 50$/MWh, the "cost" reduction is the difference between the increased value to the load 2 (50 $/MWh x 20MW = $1,000) and the cost of serving the 20 MW of load 2.

- Because all 20 MW of load 2 will be served from G2, the latter is 20 $/MWh x 20 MW = $400. The net cost reduction resulting from 1 MW incremental transmission capacity is thus $1,000 - $400 = $600. In other words, the shadow price of the transmission constraint in this case is 600$/MWh. Because the network is radial, this is the difference between the LMPs at nodes 1 and 2, which results in:
- LMP1 =20 $/MWh (Energy) + 600 $/MWh (Congestion) + 0 $/MWh (loses) = 620 $/MWh.
- LMP2 =20 $/MWh (Energy) + 0 $/MWh (Congestion) + 0$/MWh (losses) = 20$/MWh.
- Importer G1 is paid 400 MW x 620 $/MWh = $248,000.
- G2 is paid 19,550 MW x 20 $/MWh = $391,000.
- Total suppliers (G1 Importer and G2) are paid $248,000 + $391,000= $639,000.
- Exporter (Load 1) is charged 950 MW x 620 $/MWh = $589,000.
- Load 2 is charged 19,000 MW x 20 $/MWh = $380,000.

This example results in a net collection by CAISO of ($589,000 + $380,000 -$248,000 - $391,000) = $330,000. This collection is exactly equal to the congestion rent of 550MW x 600 $/MWh = $330,000 associated with the constraint on the line.

APPENDIX D – IMPORT AND EXPORT DATA





Period	Import Cost ($)	Import Volume (MWh)	Import $/MWh	Export Cost ($)	Export Volume (MWh)	Export $/Mwh (excluding Transmission Fee)	Export Transmission Fee $	Total Export Cost ($)	Total Export Cost ($/MWh)
Q1 2022	$757,542,948	16,395,626	$46	$97,207,222	2,188,341	$44	$35,845,033	$133,052,255	$61
Q2 2022	$938,503,226	15,700,230	$60	$247,470,876	4,004,332	$62	$65,590,952	$313,061,828	$78
Q3 2022	$1,687,429,973	17,971,179	$94	$649,658,737	5,923,211	$110	$97,022,188	$746,680,925	$126
Q4 2022	$1,576,266,728	12,249,584	$129	$456,967,459	3,033,206	$151	$49,683,916	$506,651,375	$167
Annual Total	**$4,959,742,875**	**62,316,619**	**$80**	**$1,451,304,293**	**15,149,090**	**$96**	**$248,142,089**	**$1,699,446,383**	$96

Period	Import Cost ($)	Import Volume (MWh)	Import $/MWh	Export Cost ($)	Export Volume (MWh)	Export $/Mwh (excluding Transmission Fee)	Export Transmission Fee $	Total Export Cost ($)	Total Export Cost ($/MWh)
Q1 2023	$965,779,253	10,432,384	$93	$240,908,997	2,542,983	$95	$36,746,100	$277,655,098	$109
Q2 2023	$362,529,868	11,525,237	$31	$149,709,246	4,058,260	$37	$58,641,857	$208,351,103	$51
Q3 2023	$912,548,000	14,560,163	$63	$598,569,200	7,889,780	$76	$114,007,315	$712,576,515	$90
Q4 2023	$586,755,433	10,932,126	$54	$181,660,921	3,018,420	$60	$43,616,166	$225,277,088	$75
Annual Total	**$2,827,612,555**	**47,449,910**	**$60**	**$1,170,848,365**	**17,509,442**	**$67**	**$253,011,439**	**1,423,859,804**	**$81**

Period	Import Cost ($)	Import Volume (MWh)	Import $/MWh	Export Cost ($)	Export Volume (MWh)	Export $/Mwh (excluding Transmission Fee)	Export Transmission Fee $	Total Export Cost ($)	Total Export Cost ($/MWh)
Q1 2024	$432,504,432	10,554,875	$41	$325,110,052	3,408,666	$95	$46,016,991	$371,127,043	$109
Q2 2024	$266,492,695	12,658,230	$21	$73,919,762	4,549,843	$16	$61,422,885	$135,342,647	$30
Q3 2024	$675,297,443	15,797,616	$43	$359,082,788	7,202,237	$50	$97,230,200	$456,312,987	$63
Q4 2024	$529,432,921	13,340,460	$40	$115,203,771	2,856,296	$40	$38,559,996	$153,763,767	$54
Annual Total	**$1,903,727,491**	**52,351,181**	**$36**	**$873,316,373**	**18,017,042**	**$48**	**$243,230,072**	**1,116,546,445**	**$62**

Period	Import Cost ($)	Import Volume (MWh)	Import $/MWh	Export Cost ($)	Export Volume (MWh)	Export $/Mwh (excluding Transmission	Export Transmission Fee $	Total Export Cost ($)	Total Export Cost ($/MWh)
2022	$4,959,742,875	62,316,619	$80	$1,451,304,293	15,149,090	$96	$248,142,089	$1,699,446,382	$112
2023	$2,827,612,555	47,449,910	$60	$1,170,848,365	17,509,442	$67	$253,011,439	$1,423,859,804	$81
2024	$1,903,727,491	52,351,181	$36	$873,316,373	18,017,042	$48	$243,230,072	$1,116,546,445	$62
Total	**$9,691,082,921**	**162,117,711**	**$60**	**$3,495,469,031**	**50,675,574**	**$69**	**$744,383,599**	**$4,239,852,630**	**$84**

Imports (Year)	Mean ($/MWh)	Std Dev ($/MWh)	1 Std Dev Range	2 Std Dev Range
2022	$80	$82	-$3 to $162	-$85 to $244
2023	$60	$44	$17 to $104	-$27 to $147
2024	$36	$29	$7 to $65	-$23 to $95
Exports (Year)	Mean ($/MWh)	Std Dev ($/MWh)	1 Std Dev Range	2 Std Dev Range
2022	$96	$85	$11 to $180	-$73 to $265
2023	$81	$50	$31 to $131	-$19 to $181
2024	$54	$35	$19 to $89	-$15 to $123

Statistical Observations

Efficiency Gap: On average over three years, California exported energy at a 30% premium (77 $/MW) compared to its import cost (59 $/MWh), confirming a successful "buy low, sell high" macro-trend. When including export transmission fee, the export premium goes well above 30$.

Volatility Suppression: The average Standard Deviation for imports dropped from $82 in 2022 to $29 in 2024, demonstrating that while prices have lowered, they have also become significantly more consistent.

Negative Price Weight: The 2 Standard Deviation ranges for the 3-Year Average still dip into negative territory, largely due to the massive weight of the 796 negative pricing hours recorded in 2024.

Analysis of Volatility and Distribution

- **Declining Volatility:** The standard deviation for both imports and exports has decreased significantly since 2022, signaling a more stabilized market as storage and renewable capacity increased.
- **Skewness and Tails:** The high standard deviation relative to the mean (especially in 2022) is driven by "extreme tails" in the distribution, where prices occasionally exceeded $350/MWh.
- **Impact of Negative Prices:** While 2024 had lower means and standard deviations, it experienced a surge in import negative pricing hours (796 hours), which pulls the lower standard deviation boundaries into negative territory.

Period	Import Hours (< $0/MWh)	Export Hours (< $0/MWh)
Q1 2024	247	241
Q2 2024	527	506
Q3 2024	11	18
Q4 2024	11	18

Import Correlation: Volume and Price Sensitivity

- **High Volume/High Price (2022):** In 2022, high natural gas prices (averaging over $9/MMBtu) and record peak loads drove both high import volumes (62 TWh) and high costs ($4.9B).
- **Declining Volume and Price (2023-2024):**
    - **2023:** Import volumes dropped to 47 TWh as hydroelectric generation increased 60% and battery/solar output grew significantly. This lowered reliance on imports and contributed to a substantial price drop.
    - **2024:** While volumes recovered slightly to 52 TWh, total import costs continued to fall significantly ($1.9B) due to lower natural gas prices (down 30-60% from 2022).

- **Hourly Distribution:** Frequency data shows imports are most common in the $28–$75/MWh range, but "extreme tails" (over 200 hours > $320/MWh) occur during peak demand when volume needs are highest.
- In 2022, California exported ~15TWh at an average of **$95.80/MWh**, capitalizing on regional heatwaves where external demand was high and supply tight.
- Export volumes increased to ~18 TWh by 2024. This growth is correlated with high midday solar production, which frequently pushes the system in an export direction during hours 10 through 16.
- **Negative Price Correlation:** An increase in solar and battery capacity has led to more hours of negative pricing (< $0/MWh). In Q2 2024 alone, there were **527 hours** where imports had negative LMPs, correlating with high internal solar surplus that required either curtailment or paying others to take the energy. Conversely, there were 506 hrs of negative exports prices during the same period.