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Industrial Decarbonization in California

Cost-Competitive Electrification with Thermal Energy Storage and Wholesale Rates

Jared Getzoff
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Executive Summary

This paper examines the prospect of replacing industrial natural gas boilers in California that provide medium to high heat with thermal energy storage (TES) and giving firms access to locational marginal price (LMP) electricity in wholesale markets under certain conditions. I accomplish this by comparing a hypothetical firm buying natural gas to meet their energy needs, to the same firm connecting directly to the transmission system and buying LMP electricity during the cheapest hours of each day. TES allows firms to select the cheapest hours of each day to charge their battery. Charging at times of excess renewable supply on the grid enables firms to meet their daily heat needs at the lowest possible cost. By comparing the modeled annual fuel costs for a firm under the natural gas and electrification scenarios, I demonstrate that it's possible for electrification to be cost-competitive with natural gas in California.

LMP is the marginal cost of delivering 1 MW of power to a specific node in the power grid. The data are 2024 CAISO day-ahead locational marginal price broken down at the zone level. Day-ahead markets are where over 90% of transactions occur, while zones represent the average price of all nodes within a zone and simplifies the analysis.[1]I use two different natural gas prices for the analysis. The first is EIA-reported California industrial natural gas prices, which likely represents the ceiling of what an industrial firm would pay. The second is California Citygate prices, which represents the floor a firm would pay. Generally, firms pay different prices somewhere between the two, with larger firms paying closer to Citygate prices and smaller firms paying closer to EIA-reported ones. I use a \$13.9525 per megawatt-hour CAISO transmission access charge, which was updated as of January 2025 from the previous rate of \$11.6304. Finally, I use a cap-and-trade permit price of \$28 per ton of CO_2, the most recent advanced auction settlement price from the February 2025 joint auction.

I have four main findings. First, the modeled annual electricity cost with an 8-hour battery charging period in the electrification scenario is lower in all three CAISO zones when compared to modeled annual fuel costs using EIA-reported California industrial natural gas prices. When compared to annual fuel costs using Citygate natural gas prices, using electricity is more expensive in all three zones, with the two southern zones SP-15 and ZP-26 being 14% and

[1] See Appendix A for a map of CAISO zones.

11% higher, respectively. In the electrification scenario, the modeled annual cost of electricity is roughly twice as high in NP-15 as in SP-15 and ZP-26.

Second, the CAISO transmission access charge (TAC), a fixed charge per MWh has considerable impact on the cost-competitiveness of electrification of industry. The breakeven CAISO TAC point between SP-15 and Citygate prices is $11.24/MWh for SP-15, and $11.84/MWh for ZP-26 when charging 8 hours per day. This means that at the breakeven TAC point, annual fuel costs in the electrification scenario are equivalent to annual fuel costs in the Citygate natural gas scenario. Further reductions in TAC increase the favorability of electrification and TES over natural gas. Electrifying in NP-15 is never cheaper than natural gas at Citygate prices, even with a $0 TAC. In the 8-hour charging scenario, TAC makes up 63% and 65% of the total annual fuel cost in SP-15 and ZP-26, respectively. Additionally, by paying the TAC but using electricity in a way that does not increase overall transmission costs, TES provides system-wide benefits and contributes to funding for future transmission investments.

Third, battery charging rates have a significant impact on the cost-competitiveness of electrification. Faster charging rates allow firms to take greater advantage of the cheapest hours of the day. SP-15 and ZP-26 reach breakeven with Citygate prices at 5.26 and 6.45 hours of daily charging, respectively. In the model, charging time is an adjustable parameter, but in practice, variation arises from factors such as grid constraints, technology choices, business needs, and battery configurations. Additionally, optimized battery charging strategies may lead to even lower annual fuel costs.[2]

Fourth, I also model the net present cost of replacing a natural gas boiler with thermal energy storage over a 30-year investment horizon. Although capital expenditures for thermal energy storage are nearly three times those of a natural gas boiler, projected discounted annual fuel costs over the investment period still account for 84% or more of the total net present cost in all three CAISO zones. These results suggest that even large differences in upfront capital expenditures are overshadowed by long-run fuel costs, though they remain sensitive to key modeling assumptions discussed later in the report. Given annual fuel costs outsized role in overall net present cost, modest changes to TAC are sufficient to make electrification cost-competitive in SP-15 and ZP-26.

[2] Conversation with an employee at a thermal battery company, March 2025.

Based on this analysis, the following recommendations will help increase thermal energy storage deployment for industrial decarbonization:

- Explore rate design with CAISO and FERC approval that allows new load to draw power from the transmission system at wholesale rates under certain market conditions such as off-peak times
- Study grid nodes where conditions are most favorable for nearby industry to electrify with thermal energy storage
- Identify industrial firms with the highest natural gas costs who may be interested in pilot programs to electrify load using wholesale rates
- Reform TAC rates, which account for over 60% of modeled annual electricity costs. Since this load is dispatchable or off-peak, it has a lower system cost and should not be charged the same as inflexible or peak loads

This research shows the potential of decarbonizing industry in California through rate design that allows firms access to wholesale prices during periods of high supply and low demand, helping to utilize excess renewable energy while still contributing to infrastructure costs.

1. Introduction

Since the passage of the Global Warming Solutions Act in 2006, the state has been a leader in efforts to reduce emissions and decarbonize its economy. Despite the state's leadership, Californians are bearing an ever-growing emotional and financial cost of a changing climate.

According to the *California Air Resources Board's (CARB) 2022 Scoping Plan*, California's industrial sector contributed approximately 1,222,000 jobs and $324 billion in output in 2019, representing 7.6% of total employment and 10.4% of state GDP.[3] According to EIA data, in 2023 California as a whole consumed 2,085 billion cubic feet of natural gas, 31% of which was consumed by the industrial sector.[4] Electrifying natural gas consumption would represent a significant increase in demand for the grid. From 2000-2022, industry in California accounted for around 23% of total emissions.[5] These industries include cement, mining and

[3] National Association of Manufacturers, *2021 California Manufacturing Facts*, 2021, https://www.nam.org/state-manufacturing-data/2021-california-manufacturing-facts/

[4] "California Profile." Accessed May 6, 2025. https://www.eia.gov/state/print.php?sid=CA.

[5] "Current California GHG Emission Inventory Data | California Air Resources Board." Accessed April 16, 2025. https://ww2.arb.ca.gov/ghg-inventory-data.

minerals, and food and beverage processing. This report does not address process emissions, which are emissions that do not come from the fuel source. Although they can account for over 60% of total emissions for cement, in many other industries they are far lower.[6]

Despite the state's strong commitment to decarbonizing industry, high industrial electricity rates make it uneconomical to electrify fossil fuel-based boilers and other industrial heat processes. According to the *Joint Agency Staff Gas Transition White Paper*, 85% of fuel combustion in the industrial sector stems from heat production.[7] Unfortunately, the *CARB 2022 Scoping Plan* notes that current industrial electricity rate structures make it potentially uneconomical to replace existing natural gas power.[8] As an E3 report on industrial decarbonization notes, "A key driver of the cost competitiveness of electric heating technologies to incumbent natural gas combustion technologies is expected to be the relative electric and gas prices". Electricity rates are significantly higher than natural gas prices in many states, but the ratio is particularly unfavorable in California, where projected average electricity prices between 2025 and 2045 exceed $35/MMBtu, while natural gas remains under $6/MMBtu over the same period.[9]

For California to achieve its net zero goal by 2045, there must be a viable path to decarbonizing industry. The Joint Agency Staff paper outlines several technological pathways for decarbonizing industry in the state: low-carbon fuels such as biomethane; hydrogen; and carbon capture, utilization, and storage (CCUS).[10] However, these pathways all face some combination of high costs, long commercialization timelines, and potential environmental impacts.

According to the same white paper, biomethane suffers from many of the same environmental harms as conventional fuel combustion and the state currently lacks infrastructure

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[6] "Emissions of Greenhouse Gases in the Manufacturing Sector | Congressional Budget Office," February 28, 2024. https://www.cbo.gov/publication/60030.

[7]California Public Utilities Commission, California Energy Commission, and California Air Resources Board. *Progress Towards a Gas Transition: A White Paper Supporting the CPUC's Long-Term Gas Planning Rulemaking (R.20-01-007)*. February 22, 2024. https://www.cpuc.ca.gov/industries-and-topics/natural-gas/long-term-gas-planning.

[8] CARB, *2022 Scoping Plan*, 2022. 209.

[9] Sean Smillie, *Decarbonizing Industrial Heat: Measuring Economic Potential and Policy Mechanisms*, n.d., fig. 38.

[10] California Public Utilities Commission, California Energy Commission, and California Air Resources Board. *2024 Joint Agency Staff Paper: Progress Towards a Gas Transition – A White Paper Supporting the CPUC's Long-Term Gas Planning Rulemaking (R.20-01-007)*. Sacramento, CA: California Public Utilities Commission, February 22, 2024. https://www.cpuc.ca.gov/industries-and-topics/natural-gas/long-term-gas-planning. 11.

for widescale fuel deployment.[11] Green hydrogen, produced from electrolysis with clean energy requires cheap electricity, which would face the same high electricity rate issue as direct industrial electrification in California. Hydrogen also has climate risks. In the 20 years after it escapes into the atmosphere it has a climate warming impact 35 times greater than CO_2.[12] Given hydrogen's small molecular size and current leakage rates from our natural gas system, it seems reasonable to expect climate impacts from hydrogen infrastructure.[13] Additionally, although there are exciting efforts to build out hydrogen infrastructure, it's currently quite limited.[14]

CCUS, by its nature, can never be cheaper than conventional natural gas as it requires additional energy and equipment to operate. Even if it were, it requires investment in a statewide CO_2 pipeline infrastructure for effective sequestration or utilization. Simply put, none of these options are currently cost-competitive with natural gas and will require significant investment and time to bring costs down.

Industrial heat pumps are another exciting technology to reduce reliance on fossil fuels. Despite having an upper heat output bound of around 300°C[15], which would not make them a viable alternative for higher heat industrial processes (some of which can require temperatures over 1000°C), E3 estimates that low temperature heat below 200°C accounts for 75% of all industrial heat needs. Unfortunately, my analysis shows that even with high rates of efficiency in the 200-300% range, they still suffer from the same high retail electricity rates that makes electrification uneconomical. Higher efficiency ground source heat pumps may be more economical but are still unable to meet the temperature needs of medium and high heat industrial processes.

Retail rates are high and vary little throughout the day, but there is also a wholesale marketplace that has different pricing dynamics. California has an independent system operator (referred to as CAISO), which manages the movement of electricity over the transmission system in most of California and a small portion of Nevada. CAISO operates a wholesale marketplace

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[11] CPUC, CEC, and CARB, *Gas Transition White Paper*, 2024. 21-30

[12] Blogs, E. D. F. "New Research Reaffirms Hydrogen's Impact on the Climate, Provides Consensus." *Energy Exchange* (blog), July 19, 2023. https://blogs.edf.org/energyexchange/2023/07/19/new-research-reaffirms-hydrogens-impact-on-the-climate-provides-consensus/.

[13] MIT News | Massachusetts Institute of Technology. "New Climate Chemistry Model Finds 'Non-Negligible' Impacts of Potential Hydrogen Fuel Leakage," December 16, 2024. https://news.mit.edu/2024/new-climate-chemistry-model-finds-non-negligible-impacts-potential-hydrogen-fuel-leakage-1216.

[14] "2024 Annual Evaluation of Fuel Cell Electric Vehicle Deployment and Hydrogen Fuel Station Network Development,"

[15] "Industrial Heat Pumps | ACEEE." Accessed May 4, 2025. https://www.aceee.org/industrial-heat-pumps.

and publishes locational marginal price (LMP) data, which represents the marginal cost of delivering 1 MW of power to a specific location in the power grid.[16] In California, retail rates through investor owned utilities (IOUs) are charged to customers by utilities through a more complex ratemaking process with the California Public Utilities Commission (CPUC) that factors in significant additional costs such as low-voltage transmission and distribution infrastructure, the utility's guaranteed rate of return, and public purpose program fees.[17] Generally, it is only load serving entities (LSEs) like utilities, grid-scale batteries, and other market participants who buy on the wholesale market and generators or independent power producers (IPPs) who sell.[18] [19]

Compared to retail electricity prices, wholesale prices more accurately reflect changes in supply and demand within a single day and throughout the seasons. California often has excess generation from solar and low demand during the day, often leading to low or negative LMPs. My analysis shows that in 2024, the three CAISO zones (show in Figure 1), NP-15, SP-15, and ZP-26, had LMPs under $30/MWh 28%, 37% and 38% of the time.[20] The phenomenon of high generation during the day and low demand is sometimes referred to as the "duck curve" and has been deepening over time.[21] Grid-scale batteries enable shifting off-peak generation to peak periods, where demand is high and generation from solar has waned. Although they also provide other grid benefits, like ancillary services, their explosive growth on the grid can be partially attributed to the value of shifting excess supply to periods of high demand.[22] Seasonally, there are greater times of excess supply and low demand in the spring, with curtailment of wind and

[16] Hinman, Cynthia. "Day-Ahead Market Overview,", 60, 2019.
[17] "Electric Rates." Accessed April 19, 2025. https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-rates.
[18] "CAISO Markets and Interconnection Process | Grid Interconnections | Generating Your Own Power | Your Business | Home - SCE." Accessed May 5, 2025. https://www.sce.com/business/generating-your-own-power/Grid-Interconnections/The-California-Independent-System-Operator--CAISO----Wholesale-Markets.
[19] "Understanding and Participating in California ISO (CAISO) Processes | Federal Energy Regulatory Commission." Accessed May 5, 2025. https://www.ferc.gov/understanding-and-participating-california-iso-caiso-processes.
[20] "Wholesale Electricity Market Data - U.S. Energy Information Administration (EIA)." Accessed March 10, 2025. https://www.eia.gov/electricity/wholesalemarkets/data.php. Data analyzed by author.
[21] "As Solar Capacity Grows, Duck Curves Are Getting Deeper in California - U.S. Energy Information Administration (EIA)." Accessed May 5, 2025. https://www.eia.gov/todayinenergy/detail.php?id=56880.
[22] Bowen, Thomas, Ilya Chernyakhovskiy, and Paul Denholm. "Grid-Scale Battery Storage: Frequently Asked Questions,"

solar more than tripling since 2019 during the season, according to Nat Bullard's annual presentation on the state of decarbonization.[23]

Figure 1. *A map of CAISO Zones. Source: "OASIS - PRODUCTION - PUBLIC - Apapjbos4392 - 0." Accessed April 20, 2025. https://oasis.caiso.com/mrioasis/logon.do.*

One technology that would be able to take advantage of periods of low wholesale prices to deliver heat throughout the entire day is thermal energy storage (TES). While a lithium-ion battery typically discharges over 2 to 4 hours[24], TES is designed to discharge over longer periods of time.[25] For example, a TES system offered by Rondo, a company based in Alameda, CA advertises itself to charge in 6-8 hours and discharge 24 hours a day.[26] By using low cost materials such as bricks or molten salt and storing electricity as heat, TES has lower storage medium costs than lithium-ion batteries.[27] [28]

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[23] Nat Bullard. "Presentations." Accessed May 9, 2025. https://www.nathanielbullard.com/presentations. Slide 86.
[24] "Duration of Utility-Scale Batteries Depends on How They're Used - U.S. Energy Information Administration (EIA)." Accessed May 5, 2025. https://www.eia.gov/todayinenergy/detail.php?id=51798.
[25] Energy.gov. "Thermal Energy Storage." Accessed May 5, 2025. https://www.energy.gov/eere/buildings/thermal-energy-storage.
[26] Rondo Energy." Accessed April 24, 2025. https://www.rondo.com/.
[27] Rissman and Gimon, *Decarbonizing U.S. Industry*. 15
[28] BloombergNEF. "Lithium-Ion Battery Pack Prices See Largest Drop Since 2017, Falling to $115 per Kilowatt-Hour: BloombergNEF," December 10, 2024. https://about.bnef.com/blog/lithium-ion-battery-pack-prices-see-largest-drop-since-2017-falling-to-115-per-kilowatt-hour-bloombergnef/.

Shifting the energy used for industrial heat in California from natural gas to TES would add a substantial amount of load to the grid. Based on EIA's data and the California Energy Commission's total electricity generation for 2023 was around 281 TWh, including imports and excluding behind the meter generation. Accounting for different efficiencies of natural gas boilers and thermal batteries, electrifying industrial heat would add roughly 167 TWh, or a 53% increase from 2023, in total grid load.[29] [30]

This paper examines the prospect of electrifying industry in California by using thermal energy storage and giving firms access to wholesale electricity rates under certain conditions, such as making this rate available for new load that is replacing fossil fuel consumption and only at off-peak times. Additionally, the policy focuses on new TES demand connecting directly to the transmission system.

Notably, this policy focuses on a technology that is commercially available today and cost-competitive with natural gas, without requiring additional state funding. We can begin decarbonizing industry today, reducing both greenhouse gas emissions and criteria air pollutants, and reinforcing California's role as a climate leader.

Section 2 of this report details a model of a firm meeting a specific energy need through natural gas and through electrification with TES. Section 3 looks at the results, including how the transmission access charge (TAC) plays a key role in the economics of TES and how variations on the charge change TES's cost-competitiveness. Section 4 of this report builds on the firm model by analyzing net present cost over a 30-year investment horizon.

2. Methodology

2.1. Annual Fuel Cost

I specify an economic model of an industrial firm with an energy need. They require a consistent number of therms per hour, some number of hours a day, and they operate every single day of the year. The annual fuel cost calculation is essentially the daily energy need of the firm multiplied by the cost of energy. Since this paper focuses on replacing natural gas, I

[29] "California Profile." Accessed May 6, 2025. https://www.eia.gov/state/print.php?sid=CA.
[30] Commission, California Energy. "2023 Total System Electric Generation." California Energy Commission. Accessed May 6, 2025. https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/2023-total-system-electric-generation. Calculated by the author.

measure a firm's energy need in therms, which is an imperial unit commonly used in the United States to measure natural gas consumption. It can be easily converted into megawatt-hours, a standard unit of electricity.

For a natural gas burning firm, buying fuel is a straightforward calculation. They require T therms of natural gas per hour, H hours per day, D_m days per month at a cost, C_m, specific to a month, and pay a cap-and-trade permit cost, P, per therm. They have a boiler efficiency of η_G, and since η_G is less than 1, they require $\frac{T}{\eta_G}$ therms per hour to make up for efficiency losses. Since my data are monthly averages for natural gas prices, I multiply the total therms needed per day by the average price of a therm in that month plus the cost per therm for a cap-and-trade (based off of standard natural gas CO_2 emissions) permit. This will give me a daily cost for that month, which I then multiply by the days in that month. I repeat this for each month of the year and sum up all monthly costs to get the total annual fuel cost of natural gas. This is referred to as the "natural gas scenario" in this paper.

$$\text{Total Annual Fuel Cost of Natural Gas} = \frac{T}{\eta_G} \cdot H \cdot \sum_{m=1}^{12} D_m \cdot (C_m + P)$$

For a firm purchasing wholesale power, let $\overline{H}_d$ represent the set of the lowest cost hours of wholesale electricity (day ahead locational marginal price or DA LMP) on day, *d*. For example, the set could include hour 1 which is between midnight and 1am on a specific day, *d*. The set is of size $H_{max}$where H_{max} is between 4 and 10 hours per day, inclusive, and represents the daily charging hours by the thermal energy storage system. For example, if H_{max} is 8, then $\overline{H}_d$ is the set of the 8 hours with the cheapest DA LMP in that day. $p_{d,h}$ is the average price of a therm of electricity on a particular day *d,* during a particular hour, *h*, where *h* is selected from the set $\overline{H}_d$. For example, if hour 9 is in $\overline{H}_d$, then $p_{d,9}$ would be the average price of a therm of electricity between 8 and 9am on a particular day, *d.* $|\overline{H}_d|$ is the cardinality of or the number of elements in the set, and is equivalent to H_{max}. ϕ is the CAISO transmission access charge (TAC) in \$/therm, which is added to every purchased therm.

The inner summation represents the average price of a therm of electricity during the set of the cheapest $\overline{H}_d$ hours on a particular day of the year. Since price data are the average cost of a therm in specific hour for every day of the year, we use the selected hourly prices for hours in $\overline{H}_d$ to calculate an average price per therm during the charging period, including the additional cost of the TAC. The outer summation multiplies the average cost of a therm on a particular day times the total required T therms per hour, H hours per day, with an efficiency rating of η_E, the efficiency of thermal energy storage, and repeats this for every day of the year. Similar to the natural gas scenario, an efficiency less than 1 means that a firm must procure more energy than they end up getting for useful work, due to efficiency losses. This is referred to as the "electrification scenario" in this paper.

$$\text{Total Annual Fuel Cost of Electricity} = \frac{T}{\eta_E} \cdot H \cdot \sum_{d=1}^{365} \left(\frac{1}{\left|\overline{H}_d\right|} \sum_{h \in \overline{H}_d} p_{d,h} + \phi \right)$$

2.2. Net Present Cost

I next construct a simple model of an investment decision by a firm, over a timeframe, T, in years, facing a discount rate δ, an initial capital investment in thermal energy storage, FC, an initial fuel cost per year, $VC_{\text{elec},0}$, which does not include TAC, an electricity price annual growth rate of γ, an initial annual cost from TAC, $VC_{\phi,0}$, and an annual TAC growth rate, λ. This model represents a firm making the decision now to switch to and invest in thermal energy storage in year 0 and spend FC_E. $VC_{\text{elec},0} + VC_{\phi,0}$, is equivalent to the total annual fuel cost in the electrification scenario described in the previous section. Then from year 1 through year T, they purchase electricity to meet their needs. Inside the summation represents the variable costs in a given year, discounted by some discount rate and growing from the base year variable cost at the previously described growth rates. The summation represents the sum of all of the variable costs over the entire investment horizon.

$$\text{Net Present Cost} = \mathrm{FC_E} + \sum_{\mathrm{t}=0}^{\mathrm{T}} \delta^{\mathrm{t}} \cdot (VC_{elec,0} \cdot \gamma^t + VC_{\phi,0} \cdot \lambda^t)$$

For a firm waiting until year τ to replace their natural gas boiler when it breaks in the future with thermal energy storage, and a cost of natural gas fuel in year 0, $VC_{\text{gas},0}$, (which represents the total annual fuel cost in the natural gas scenario, described in the previous section). $VC_{\text{elec},0} + VC_{\phi,0}$ is again equivalent to the total annual fuel cost in the electrification scenario described in the previous section. The firm faces a cost decision represented by the following:

$$\text{Net Present Cost Future Replacement with TES} = \sum_{t=0}^{\tau-1}(\delta^t \cdot VC_{\text{gas},0}) + FC_E \cdot \delta^\tau + \sum_{t=\tau}^{T} \delta^t \cdot (VC_{elec,0} \cdot \gamma^t + VC_{\phi,0} \cdot \lambda^t)$$

Finally, I compare both of these net present costs, to a baseline or counterfactual scenario of a firm replacing their natural gas boiler with another natural gas boiler in year τ when it breaks. They pay a capital cost, FC_{GAS}, to purchase a new boiler. The net present cost is represented by the following equation:

$$\text{Net Present Cost Future Replacement Gas} = \sum_{t=0}^{T}(\delta^t \cdot VC_{\text{gas},0}) + FC_{GAS} \cdot \delta^\tau$$

2.3. Model Assumptions

This model assumes that charging and discharging occurs over a 24-hour timeframe. However, experts from thermal energy storage companies have noted that they are also studying 48-hour charge and discharge periods, with a 16-hour charging window. This ignores the potential benefits of an approach that looks at the cheapest set of hours (e.g. 16) over a 48-hour time frame, where a battery can better handle day-to-day price fluctuations by charging more on the cheaper day. The tradeoff is between a higher capital expenditure of a larger battery with lower variable costs. Conversations with one battery company noted that the price of daily charging at a node with extremely favorable conditions for 48-hour charging was lower than the traditional bottom-8 24-hour charging approach.[31] This model is also assuming a battery needs to charge to 100% each day to meet a firm's energy needs. Additionally, the model does not consider the output gas flow rates of the battery and how that affects the rate of discharge of the battery.

This model assumes that a battery meets charging and discharging needs during the timeframe identified for charging and does not require "ramp-up" time to reach full charging or discharging rates.

This model also assumes that shifting industrial natural gas consumption into electricity demand onto a local node does not significantly change the LMP at that node or negatively affect

[31] Conversation with an employee at a thermal battery company, March 2025.

other customers or the cost of the overall system. This assumption is supported by findings from Der Jagt et al., who report that even under scenarios with substantial deployment of flexible demand sinks—loads that can operate flexibly when prices are low—average electricity prices remained stable and system costs were not significantly affected.[32]

This model also does not consider how federal tax incentives such as Advanced Manufacturing Production Credit (45X), Qualifying Advanced Energy Project Credit (48C), Clean Fuel Production Credit (45Z) or specific state incentives may affect the economics of TES.

This model does not include operations and maintenance costs for TES or natural gas boilers. It uses technology costs, storage costs, boiler and battery efficiency, and power input and output equipment costs from and Energy Innovation study by Jeffrey Rissman and Eric Gimon.[33]

This research assumes that new load connects directly to the transmission system and does not account for the cost of that connection. It also assumes a clear and feasible path of interconnection for a spur line, though in practice there may be property or siting constraints. It may be more economical for smaller projects to connect to the distribution system, given the cost of a transmission connection. Further research is needed to understand the cost tradeoffs.

2.4. CAISO and the Transmission Access Charge

The CAISO Transmission Access Charge (TAC) calculation is the sum of all annual transmission revenue requirements (TRR) of participating transmission owners (PTO) divided by the sum of the estimated annual gross load in MWh in each PTOs system. This is represented by the following equation:

$$TAC = \frac{\sum TRR\ (\$)}{\sum MWh}$$

The TRR is the mechanism through which a PTO recovers the associated costs of their transmission facilities that they have turned over to the independent system operator (ISO) for operation. Each TRR is broken into regional (R-TRR) and local portions (L-TRR). Regional

[32] Sam van der Jagt, Neha Patankar, and Jesse D. Jenkins, *Understanding the Role and Design Space of Demand Sinks in Low-Carbon Power Systems*, *Energy and Climate Change* 5 (2024). 3.
[33] Rissman, Jeffrey, and Eric Gimon. "Decarbonizing U.S. Industry While Supporting a High-Renewables Grid," 15-16

refers to high-voltage lines over 200 kilovolts (kV), while local refers to lines under 200 kV. Local is used to serve a specific PTO's load while regional is used to move power around the ISO. Although this sounds like transmission vs. distribution, some lines that are in the local definition may still be classified as transmission by the ISO. PTOs are mostly investor-owned utilities (IOUs), municipal utilities, and public utility districts.

R-TRR is recovered through a uniform volumetric charge, the regional transmission access charge (R-TAC), and as of writing currently stands at $13.9525/MWh.[34] The ISO then returns a portion of the funds collected through the R-TAC to the appropriate PTO based on the ISO Tariff Appendix F Rate Schedule. The L-TRR is collected by the PTO from its customers and can vary by PTO. However, some PTOs are not load-serving entities; these are typically developers who recover their costs solely through the R-TRR. This research focuses on the Regional Transmission Access Charge (R-TAC) and is referred to simply as "TAC" throughout this paper.[35]

Both the TRR and the estimated gross load are approved by the Federal Energy Regulatory Commission (FERC) through a rate case. During this time, the PTO must demonstrate that all costs that contribute to the TRR are "just and reasonable". I've simplified this description to ignore major differences between PTOs, non-PTOs, wheeling access charges, the transmission revenue balancing account, and wholesale exports as it's not entirely relevant to this paper. [36]

Since the TAC is a function of the TRR and the gross load, increasing gross load, the denominator, can lower the TAC if the increased load does not drive-up transmission costs, the numerator (e.g. require building more transmission to accommodate the load). Thermal energy storage, by consuming power when demand is low increases overall load without increasing overall transmission costs, supporting future transmission investments and spreading the benefits of a lower TAC to all system users. However, more study is needed to understand how moving

[34] California ISO, *High Voltage Access Charge Rates*, 2024.
[35] The Public Advocates Office describes TAC slightly differently: it is split into a high-voltage (HV) and low-voltage (LV) rate. HV (200 kV and above) has a single rate across the CAISO territory and is paid by transmission system users. LV (below 200 kV), used by utilities to serve their own customers, is paid by retail customers in utility service areas and varies by utility. *Public Advocates Office Transmission Data Dashboard*, 2024.
[36] California ISO, *How Transmission Cost Recovery Through the Transmission Access Charge Works Today: Background White Paper*, Market & Infrastructure Policy, April 12, 2017. 4-10

large amounts of new load onto the system from industry may impact transmission investment needs.

2.4.1. TAC Rates and Expectations

Figure 2 shows a chart of the high voltage TAC since 2009 from the Public Advocates Office (PAO). The January 2025 TAC rates included a total of $2.835 billion in filed TRRs, including $817 million from PG&E on an estimated annual gross load of 90,085,987 MWh in their territory. By dividing PG&E's TRR by the gross load you get a rate of $9.0699/MWh, referred to as the HV Utility Specific Rate. This differs from the TAC rate of $13.9525/MWh, whose calculation is referred to in the previous section.[37] The HV Utility Specific Rate is used to determine how much money the ISO should remit to the specific PTO (in this case PG&E) of the overall pool of collected TACs.

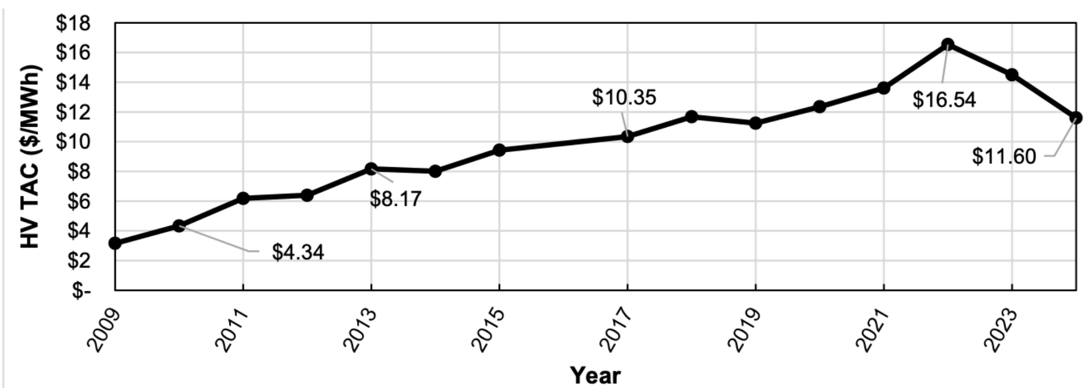

Figure 2. *Historical CAISO-Wide High Voltage TAC Rate, provided by the Public Advocates Office. Does not include the January 2025 rate of $13.9525/MWh. Source: "Public Advocates Office Transmission Data Dashboard," 2024.*

The Public Advocates Office (PAO) has put together TAC forecasts, show in Figure 3, based on different transmission build out scenarios. This research uses a 4% TAC growth rate for net present cost calculations, which is roughly in line with their "TAC with 2023-2024 TPP Projects" scenario. In the figure, you can see there is considerable uncertainty in how TAC may change in the future.

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[37] California ISO, *High Voltage Access Charge Rates*, 2024.

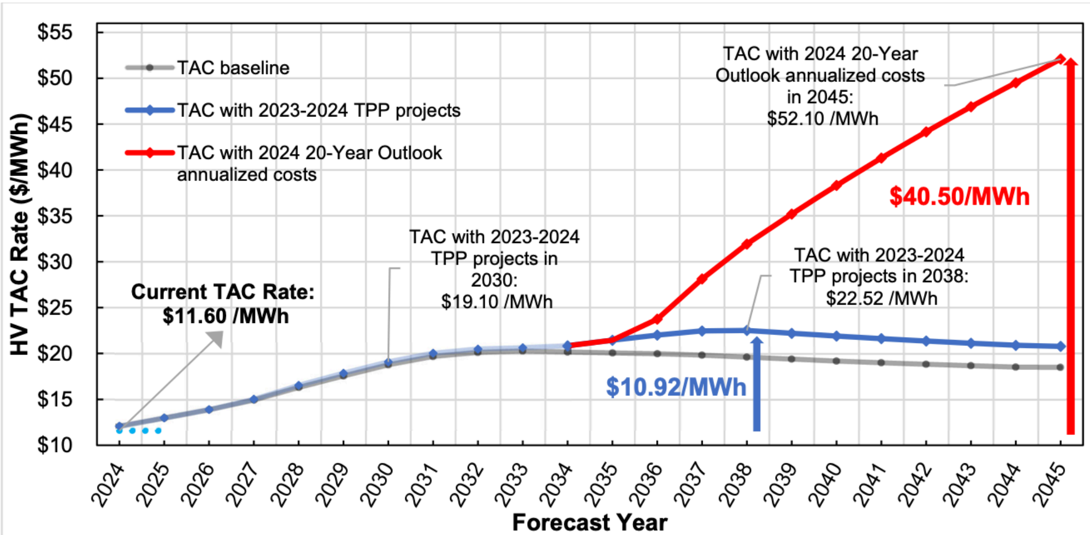

Figure 3. *HV TAC Rates Forecast and Forecast Scenarios. Source "Public Advocates Office Transmission Data Dashboard," 2024.*

3. Data

I constructed an excel model to calculate annual fuel costs and net present cost for a firm in the natural gas and electrification scenarios. I collected data from the U.S. Energy Information Administration (EIA), including CAISO day ahead locational marginal price data (DA LMP), natural gas prices, and industrial retail prices. I used capital cost data from an Energy Innovation study. Finally, I used various python scripts to clean data or compress 15-minute CAISO DA LMP data into hourly data.

3.1. Natural Gas

The price firms pay for natural gas is not straightforward given the deregulated nature of the market. Customers are divided up into core and non-core customers. Core is mostly comprised of residential, small businesses, and industrial customers who use the utility distribution systems to purchase gas. Non-core customers manage the purchase and distribution of natural gas themselves, or through a third-party.[38]

In this report, EIA-reported data are used to estimate what core customers pay, but they likely do not reflect the prices paid for the majority of industrial natural gas consumption. This is because smaller industrial firms rely on the natural gas system run by utilities and regulated by

[38] California Public Utilities Commission. *High Natural Gas Prices in Winter 2022–23: Part I – A Staff White Paper Supporting CPUC Investigation I.23-03-008*. Updated February 10, 2025, 19-20, https://www.cpuc.ca.gov/.

the state. A therm of gas delivered through the regulated system averaged around $1.39 in 2024, more than twice the cost of a therm at the spot price (discussed more below).[39] [40] California has a deregulated natural gas market, so firms are free to procure gas on their own through their own pipelines or other distribution infrastructure.[41] Table 1 shows how the majority of emissions come from the largest industrial facilities, while the smallest 73% of facilities account for only 7% of emissions.

Table 1. *A breakdown of industry in California. Source: An employee of a thermal energy storage company. February 6, 2023.*

Emissions Bucket (MT CO2e)	Count of Facilities	Emissions (MT CO2e)	Thermal Load (MW)	% of Facilities	% of Emissions	% of Thermal Load
0-10K	143	574861	222	25%	1%	1%
10-50K	282	5966211	2290	48%	6%	8%
50-100K	46	3101396	1180	8%	3%	4%
100-250K	38	6237676	2297	7%	7%	8%
250-500K	23	7488828	2836	4%	8%	10%
500-1M	23	16789785	5506	4%	18%	20%
1-2M	19	25808848	8362	3%	27%	30%
2-4M	7	19441522	3832	1%	20%	14%
4M+	2	9750761	1263	0.30%	10%	5%

Citygate prices generally reflect regional natural gas prices and represent the total cost paid by a local distribution company at the point the gas is received from a pipeline operator. [42] Prices paid by non-core customers are not publicly reported,[43] so my analysis uses Citygate price as a conservative estimate for what most industry pays. This approach may bias results in favor of natural gas as Citygate excludes final costs of local distribution and storage. Data were

[39] "California Natural Gas Industrial Price (Dollars per Thousand Cubic Feet)." Accessed May 5, 2025. https://www.eia.gov/dnav/ng/hist/n3035ca3m.htm. Data converted by the author.
[40] "Natural Gas Citygate Price in California (Dollars per Thousand Cubic Feet)." Accessed May 5, 2025. https://www.eia.gov/dnav/ng/hist/n3050ca3m.htm. Data converted by the author.
[41] Email conversation with CPUC energy division employee. March 28, 2025.
[42] "Table Definitions, Sources, and Explanatory Notes." Accessed March 5, 2025. https://www.eia.gov/dnav/ng/TblDefs/ng_pri_sum_tbldef2.asp.
2025. https://www.naturalgasintel.com/glossary/what-is-a-natural-gas-citygate/
[43] Email conversation with CPUC energy division employee. March 28, 2025.

sourced from EIA as the California Citygate monthly average price for one thousand cubic feet of natural gas ($/Mcf) and converted to therms.[44]

When calculating annual fuel costs from natural gas, I include a $28 per metric ton of CO_2 or a $0.15 per therm charge, before accounting for efficiency losses. A single cap and trade permit covers the emissions of 1 metric ton of CO_2. I added this into the cost of the annual fuel costs from natural gas for Citygate pricing, since non-core customers who purchase natural gas on their own must acquire permits for their carbon emissions under cap-and-trade.[45] To prevent "emissions leakage", industrial firms simply relocating to an unregulated state, many firms are given a free allocation of cap-and-trade permits, sometimes referred to as "free allowances".[46] The opportunity cost of using a permit is the amount a firm could earn by selling it on the market, so continuing to burn natural gas includes this forgone value.

3.2. Electricity

I represent wholesale prices by using 2024 hourly zonal CAISO day-ahead locational marginal price (DA LMP) data for zones from EIA. Most transactions settle in the DA markets instead of the real-time markets, with energy costs from DA transactions representing 93% of total wholesale energy costs.[47] I use zone-level pricing data to simplify my analysis. I wrote a series of python scripts to process this data and find the average price of the cheapest 4 to 10 hours per day, for every day in the 2024 dataset.

The original EIA dataset had several missing days. To handle this, using Excel I took the overall daily average cost for the included days and multiplied by the number of days in the month. For example, if there were only 20 days of available data for March 2024, I summed up the average cost for each day, divided it by 20, then multiplied it by 31, the number of days in the month. Since 2024 was a leap year, I used 29 days for the month of February.

Table 2 shows the average price for the past 5 years with 2024, the year used for this analysis, being cheaper than previous years (except for NP-15). This paper does not incorporate forecasts of wholesale prices in CAISO, and further sensitivity analysis is needed to understand

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[44] EIA, *California Citygate Price*, accessed May 5, 2025.
[45] Conversation with a former employee at a thermal battery company, April 2025.
[46] "Allowance Allocation | California Air Resources Board." Accessed May 5, 2025. https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program/allowance-allocation.
[47] California Independent System Operator. *2023 Annual Report on Market Issues and Performance*. Department of Market Monitoring. July 29, 2024. https://www.caiso.com/documents/2023-annual-report-on-market-issues-and-performance.pdf. 87-88.

how projections of wholesale price changes may affect the long run cost-competitiveness of thermal energy storage.

Table 2. *Average annual DA LMP price by zone in $/MWh. Source: Calculated average DA LMP in $/MWh. Source: EIA, Wholesale Electricity Market Data, accessed March 10, 2025. Data calculated by author.*

Annual Average Price DA LMP $/MWh						
	All Hours			Between 8am-6pm		
Year	NP-15	SP-15	ZP-26	NP-15	SP-15	ZP-26
2020	32.22	33.98	30.86	27.32	27.73	24.81
2021	52.36	49.88	48.75	45.17	49.07	39.12
2022	89.24	85.10	82.40	77.42	69.30	65.65
2023	61.44	57.15	55.08	51.32	40.04	38.39
2024	49.26	32.36	31.59	32.56	15.88	15.28

Finally, I add an additional CAISO transmission access charge (TAC) of $13.9525/MWh or $0.41/therm, before accounting for efficiency losses from heating.[48] Unlike natural gas, a buyer on the wholesale electricity market does not pay cap-and-trade costs directly, as the cost of energy includes the cost of cap-and-trade permits to the generator.[49]

3.3. Efficiency

I used 95% efficiency for thermal energy storage[50] and 85% for natural gas boilers, [51] efficiencies commonly cited in other studies and also recommended to me by two employees of thermal energy storage companies. In my analysis, for a firm meeting an energy need of 100 therms using natural gas, they would need to purchase roughly 117.6 therms, while if they were meeting the need with thermal energy storage, they would need to purchase around 105.3 therms of electricity.

[48] California Independent System Operator, *High Voltage Access Charge Rates*, 2024.
[49] Conversation with a former employee at a thermal battery company, April 2025.
[50] Rissman, Jeffrey, and Eric Gimon. "Decarbonizing U.S. Industry While Supporting a High-Renewables Grid," 27,
[51] Sean Smillie, *Decarbonizing Industrial Heat: Measuring Economic Potential and Policy Mechanisms*. 37.

3.4. Capital Costs

For capital costs, I relied on an E3 report, *Decarbonizing Industrial Heat: Measuring Economic Potential and Policy Mechanisms*. They use estimates from an Energy Innovation study.[52] Capital costs for a natural gas steam boiler are $234/kW-out, thermal energy storage is $300/kW-out, $100/kW-in, $5/kWh of storage.[53] kW-out is output power used for heat, while kW-in would be power coming in to charge a battery. I ignore operations and maintenance costs and assume they are a small portion of overall net present costs.

4. Results

4.1. Default Scenario

In the default scenario I modeled annual fuel costs with the current CAISO TAC, the most recent advanced cap-and-trade permit price, and a charging time of 8 hours per day. The electrification scenario is lower in all three CAISO zones when compared to EIA-reported industrial data. When compared to annual fuel costs using Citygate natural gas prices, costs in all three zones are higher, with the two southern zones SP-15 and ZP-26 being 14% and 11% higher, respectively. In the electrification scenario, modeled annual fuel costs are roughly twice as high in NP-15 as in SP-15 and ZP-26.

Table 3. *Annual fuel cost results with default parameters, rounded to 4 significant figures.*

Market Parameters	
CAISO TAC	$13.9525 / MWh
Cap-and-Trade Permit Price	$28 / ton of CO2
Firm Parameters	
Therms per hour	100
Hours per day	24
Battery charge time per day (hours)	8
Zone	**Annual Fuel Cost**
NP-15	$1,114,000
SP-15	$603,600
ZP-26	$586,400

[52] Rissman, Jeffrey, and Eric Gimon. "Decarbonizing U.S. Industry While Supporting a High-Renewables Grid,"
[53] Sean Smillie, *Decarbonizing Industrial Heat: Measuring Economic Potential and Policy Mechanisms*. Excel model associated with study.

Gas Rate	**Annual Fuel Cost**
EIA	$1,222,000
Citygate	$530,200

The average annual fuel cost of delivered energy (considering boiler and battery efficiency) in the modeled scenario was $42.70/MWh in NP-15, $23.20/MWh in SP-15, $22.54/MWh in ZP-26, $47.50/MWh using EIA natural gas data, $20.60/MWh using Citygate natural gas data, and $185.50 using industrial retail rates.

4.1.1. Varying the CAISO Transmission Access Charge and Charging Time

The CAISO Transmission Access Charge (TAC) makes up a significant portion of the annual fuel cost in the electrification scenario (Table 4).

Table 4. *The percentage of the total annual fuel cost in the electrification scenario that comes from the CAISO Transmission Access Charge.*

Zone	% cost from TAC
NP-15	34%
SP-15	63%
ZP-26	65%

To look at how changes in TAC affect the economics of electrification, I defined a breakeven multiplier, M, as the amount you would need to multiply the total annual fuel cost in the electrification scenario, C_{elec}, to break even with the cost of the Citygate natural gas scenario, C_{gas}. When $M > 1$, electrification is cheaper, when $M < 1$, electrification is more expensive, and when $M = 1$, the two scenario costs are the same:

$$M = \frac{C_{gas}}{C_{elec}}$$

The following graphs show how the Transmission Access Charge (TAC) affects the breakeven multiplier, with each panel representing a fixed battery charging duration (4, 6, 8, or 10 hours). The y-axis is the breakeven multiplier, M, and the y-axis represents different values of the TAC.

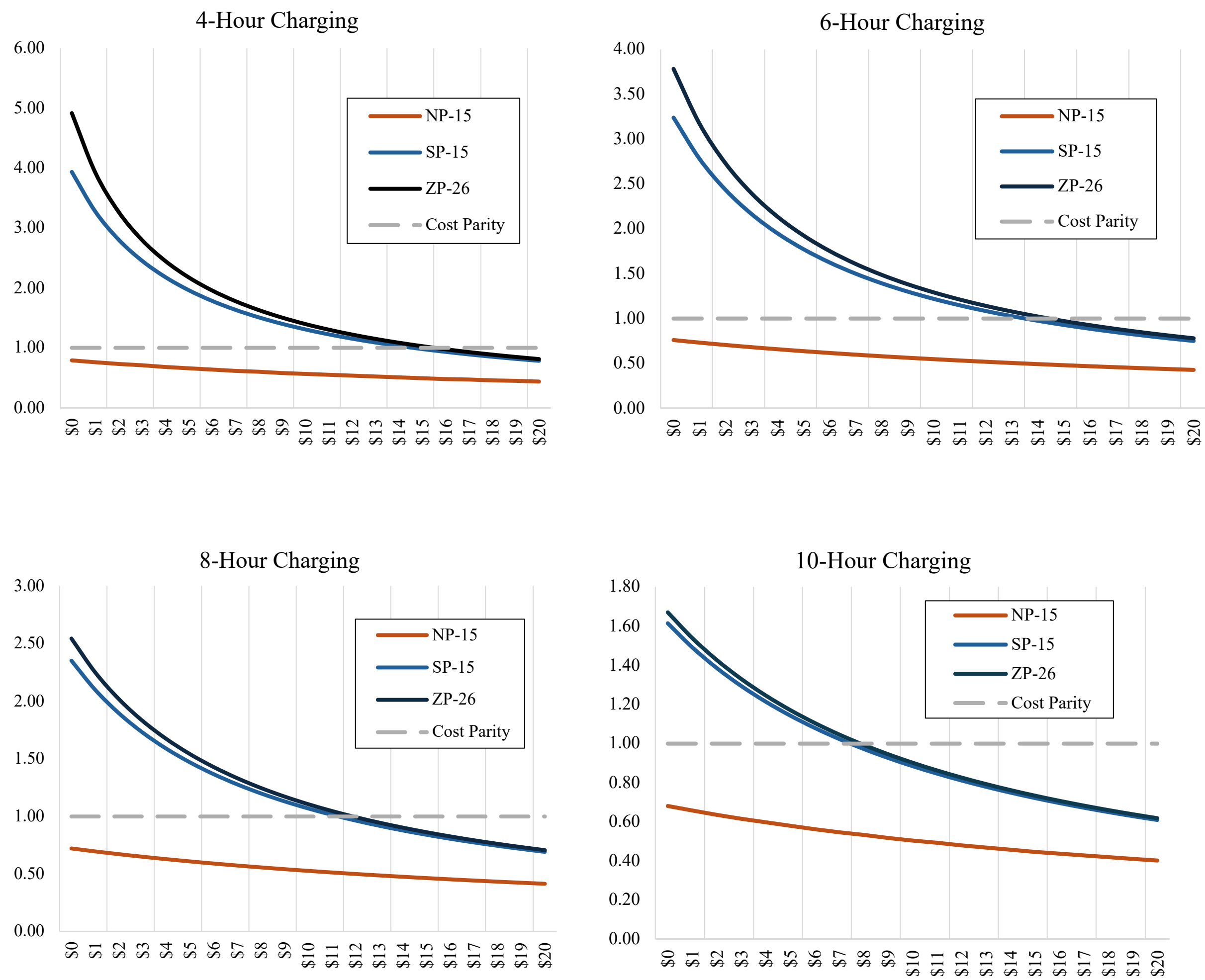

Figure 4. *Charts showing a sensitivity analysis varying the transmission access charge.*

In the default 8-hour daily charging scenario, this shows that the breakeven TAC is between \$11 and \$12 (\$11.24 for SP-15 and \$11.84 for ZP-26). As the number of charging hours goes down, the breakeven TAC goes up, meaning faster charging offsets some of the increased cost from a higher TAC. In the 6-hour daily charging scenario, the breakeven TAC is \$13.52 for SP-15 and \$14.39 for ZP-26. Additionally, we can see that TAC has a significant impact on the multiplier. NP-15 is mostly not cost-competitive. To the left of the breakeven point, each incremental reduction in the TAC yields an increasingly large increase in the breakeven multiplier, reflecting increasing marginal returns to TAC reductions.

Emphasizing the impact of charging times, I also plot the breakeven multiplier, M, holding the TAC constant at the current January 2025 level of \$13.9525/MWh and varying the number of daily charging hours.[54] This shows how a battery that needs fewer hours each day to charge to meet a firm's energy need can take greater advantage of the lowest priced hours of the day. Charging hours is a discrete function in my model, so I can't test non-integer daily charging hours. However, by calculating the total annual fuel cost at daily charging hours with integer values of 5, 6, and 7, for SP-15 and ZP-26, and performing a linear interpolation between the modeled values, I get a breakeven point of 5.26 hours per day for SP-15 and 6.45 hours per day ZP-26. More rapid charging speeds increase the cost-competitiveness of electrification. The results also continue to show the relative cost-competitiveness of locating in the ZP-26 zone compared to other zones. In this analysis, NP-15 is never cost-competitive with the Citygate natural gas scenario.

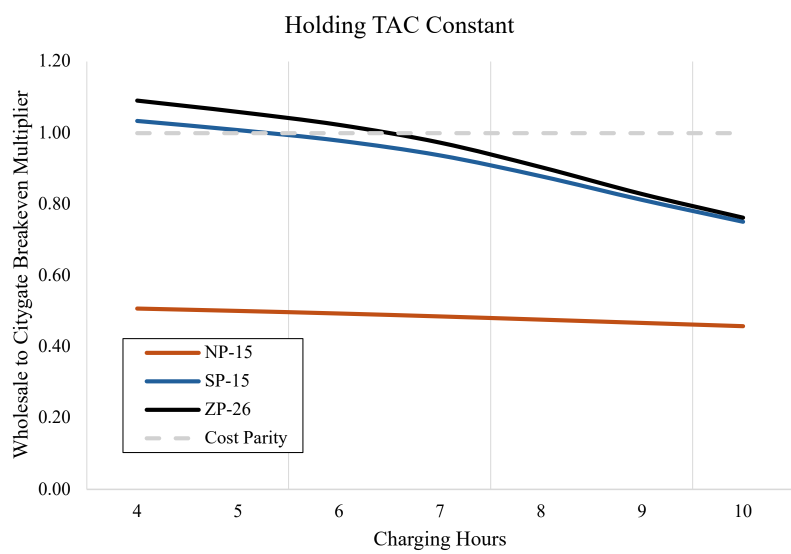

Figure 5. *A plot of the breakeven multiplier with daily charging hours.*

4.1.2. Cap-and-Trade Permit Price Sensitivity

I also performed a sensitivity analysis on the cap-and-trade permit price, holding the transmission access charge constant at its January 2025 level and modeling 8 hours of daily charging. The Citygate natural gas scenario reaches breakeven with SP-15 at a permit price of $41.40 and with ZP-26 at a permit price of $38.25. Figure 6 shows a plot of annual fuel costs

[54] California Independent System Operator, *High Voltage Access Charge Rates*, 2024.

varying the permit price from \$5 per metric ton of CO_2 to \$50. Incorporating permit price forecasts into future analyses can help better understand the economics of electrifying industrial load. This paper is not advocating for directly ratcheting up cap-and-trade permit prices without offering a viable and cost-competitive substitute for natural gas combustion.

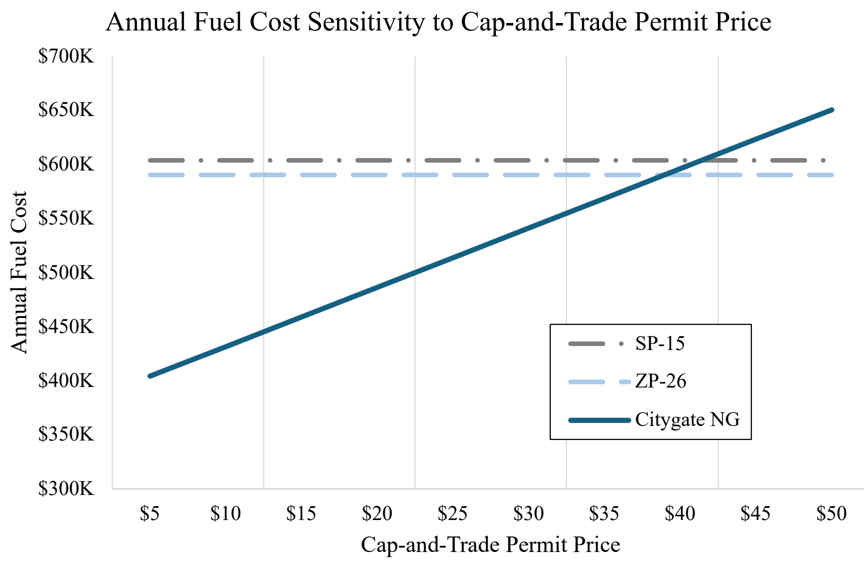

Figure 6. *A plot of cap-and-trade permit prices and its impact on the modeled annual fuel cost using Citygate natural gas prices. SP-15 and ZP-26 plotted for reference. NP-15 excluded since it remains uneconomical.*

4.1.1. Citygate Cost Overhead Sensitivity Analysis

I use Citygate as the lowest price a large industrial firm would be paying for natural gas in this analysis. However, if firms incur additional costs such as storage and distribution fees then they would face higher natural gas prices, tilting the economics in favor a thermal energy storage. Figure 7 plots a cost adjustment factor on the x-axis: how a percentage increase in the cost of a therm of Citygate natural gas changes the breakeven point between annual fuel costs from the natural gas scenario with those of the electrification scenario. A multiplier below 1 means the modeled natural gas scenario is cheaper, while above 1 means the modeled electrification scenario is cheaper. This analysis is simplified and directly adjusts annual fuel costs that include cap-and-trade permit prices. The modeled breakeven cost adjustment factor for SP-15 is 11%, for ZP-25 14%, and for NP-15, which is left off this graph, 110%.

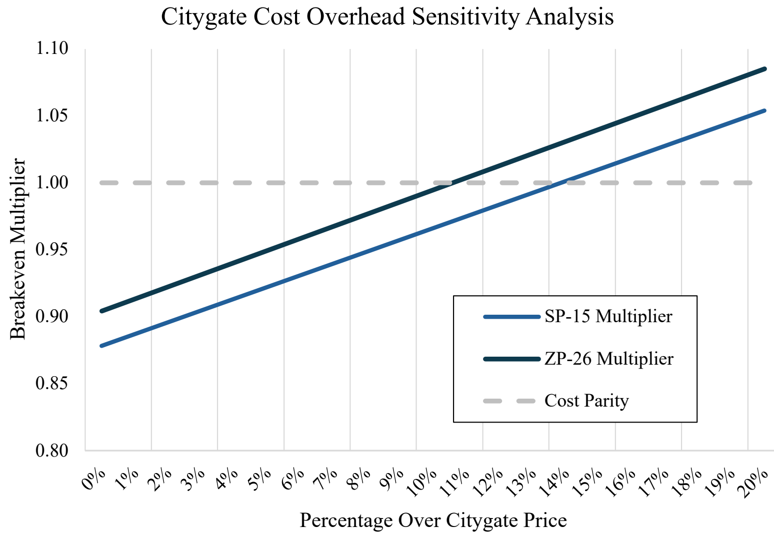

Figure 7. *A sensitivity analysis of how costs firms face over the Citygate price changes the economics of annual fuel costs of natural gas and thermal energy storage.*

4.1.2. Industrial Heat Pumps

Industrial Heat Pumps are another exciting pathway for industrial decarbonization. However, they have similar challenges related to electricity costs and market access as those faced by thermal batteries. At the average retail electricity rate of $5.44/therm, or $185.50/MWh using EIA industrial retail rate data for California from 2024, a firm with the same modeled energy need would spend $5,013,000 annually at 95% efficiency (an electric boiler), $2,381,000 annually at 200% efficiency (a lower efficiency air source industrial heat pump) and $1,588,000 annually at 300% efficiency (a higher efficiency air source industrial heat pump). Ground source heat pumps achieve higher COPs in the 3 to 5 range (COP or coefficient of performance is a measure of heat pump efficiency, where 300% efficiency is a COP of 3). However, since industrial heat pumps do not include storage and therefore do not allow a firm to charge during the cheapest hours of the day, without a firm building additional storage, they would add to peak grid demand. Additionally, current heat pumps are unable to meet the temperature needs of medium to high heat industrial processes. Regardless, they could be appropriate for an intermittent, low heat need. An E3 study on industrial decarbonization analyzes industrial heat pumps extensively.[55]

[55] Sean Smillie, *Decarbonizing Industrial Heat: Measuring Economic Potential and Policy Mechanisms*

4.2. Net Present Cost

Next, I model the net present cost, representing the total cost with future costs discounted, of investing in thermal energy storage. I use the current January 2025 CAISO TAC, default 8-hour daily charging hours, default cap-and-trade permit price of $28, and a 30-year investment duration. Additionally, I use a 6% discount rate, a 2% growth in electricity rates, a 4% growth in the TAC, and a 2% growth rate in natural gas prices. A 6% discount rate is near the low end of discount rates used in Lazard levelized cost of energy studies.[56] The growth rates for electricity and natural gas were more difficult to select. EIA predicts a 27% increase in natural gas prices in 2026.[57] For wholesale electricity prices, EIA forecasts flat growth for next year after accounting for inflation.[58] I use a 4% TAC growth rate for net present cost calculations, which is roughly in line with the PAO "TAC with 2023-2024 TPP Projects" scenario.[59] The discount rate and all growth rates are expressed in real terms assuming a constant rate inflation.

- Total net present cost over the project lifetime when switching to thermal energy storage in year 0 was $22,570,00 for NP-15, $14,060,000 for SP-15, and $13,770,00 for ZP-15.
- For a firm using natural gas, where their boiler breaks in year 10 and they decide to replace with another natural gas boiler, the net present cost is $21,190,000 for EIA-report natural gas prices and $9,630,000 for Citygate natural gas prices.
- For a firm using natural gas at EIA-reported prices and replacing their boiler, when it breaks in year 10, with thermal energy storage, their net present cost is $23,910,00 for NP-15, $18,180,000 for SP-15, and $17,990,00 for ZP-15.
- For a firm using natural gas at Citygate reported prices and replacing their boiler, when it breaks in year 10, with thermal energy storage, their net present cost is $18,590,000 for NP-15, $12,860,000 for SP-15, and $12,670,000 for ZP-15.
- Capital expenditures for thermal storage for a firm using 100 therms an hour, charging at 300 therms an hour for 8 hours a day were $2,156,000. This excludes the cost of interconnection with the transmission system.

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[56] Lazard, *Lazard's Levelized Cost of Energy+ Version 17.0* (New York: Lazard, June 2024), 13.
[57] "EIA Expects Higher Wholesale U.S. Natural Gas Prices as Demand Increases - U.S. Energy Information Administration (EIA)." Accessed May 9, 2025. https://www.eia.gov/todayinenergy/detail.php?id=64344.
[58] "Forecast Wholesale Power Prices and Retail Electricity Prices Rise Modestly in 2025 - U.S. Energy Information Administration (EIA)." Accessed May 9, 2025. https://www.eia.gov/todayinenergy/detail.php?id=64384.
[59] California ISO, *High Voltage Access Charge Rates*, 2024

- Capital expenditures for a firm purchasing a new natural gas steam boiler providing 100 therms per hour were $806,800.

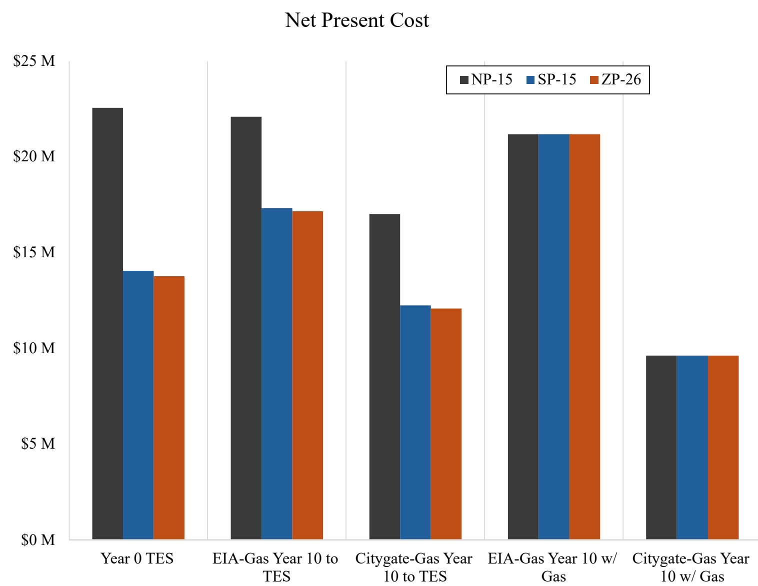


Figure 8. *Net present cost with total net present cost on the y-axis.*

The results are similar to the annual fuel cost analysis in that the electrification scenario is cheaper than EIA-reported natural gas, but more expensive than Citygate natural gas. Additionally, NP-15 remains significantly more expensive than SP-15 and ZP-15. Results also align with a blog post by E3 from an earlier reference report, "Our analysis suggests that policy support that reduces upfront investment costs, like low-cost loans and investment tax credits, have limited potential to drive high heat pump adoption rates since capital cost is a small portion of the overall levelized cost of heat. Conversely, policies targeting operating costs, like carbon pricing and production tax credits, can drive much higher levels of adoption and have the potential to be transformative".[60]

This analysis does not include costs for interconnection with the grid. A recent Lawrence Berkeley National Lab blog post put the cost in the past five years at $81/kW.[61] I performed a rough estimate using figures from the blog post. A 1 MW facility would face a cost of around

[60] Perelman, Tali. "Measuring the Economic Potential of Decarbonized Heat." *E3* (blog), October 30, 2024. https://www.ethree.com/decarbonizing-industrial-heat/.
[61] "Grid Connection Barriers To New-Build Power Plants In the United States | Energy Markets & Policy." Accessed May 6, 2025. https://emp.lbl.gov/news/grid-connection-barriers-new-build-power-plants-united-states.

$81,000, while a large 500 MW facility would need to spend $40,500,000. Finally, the modeled 100 therm per hour facility, which is roughly 3 MW, would need to spend $243,000. Further study is needed to understand costs associated with grid interconnection.

Given the high uncertainty around forecasts for natural gas and electricity price growth, transmission access rates, and discount rates, the following sections present additional scenario analysis.

4.2.1. Discount Rate Sensitivity Analysis

Varying discount rates between 4 and 12% shows that net present costs between moving to thermal energy storage today and sticking with a gas boiler in the future converge as the discount rate increases. This occurs because higher discounting decreases the weight of future fuel costs, shrinking the difference between natural gas and electricity over time. The three charts below represent the net present cost in the three different CAISO zones. On the y-axis is total discounted cost over the entire lifetime of the investment, with the same parameters from the default analysis except for varying the discount rate. On the x-axis is the varied discount rate. The dashed and dotted lines are the total cost running a natural gas boiler that breaks in year 10, then replacing it with a natural gas boiler. These values are the same in all three charts since they do not depend on electricity prices. EIA-Gas Year 10 Replacement to TES and Citygate-Gas Year 10 Replacement to TES represent a firm using natural gas at EIA prices and Citygate prices, respectively, until year 10 when the boiler breaks, and then switching to thermal energy storage and using electricity in that specific CAISO zone for the rest of the analysis timeline.

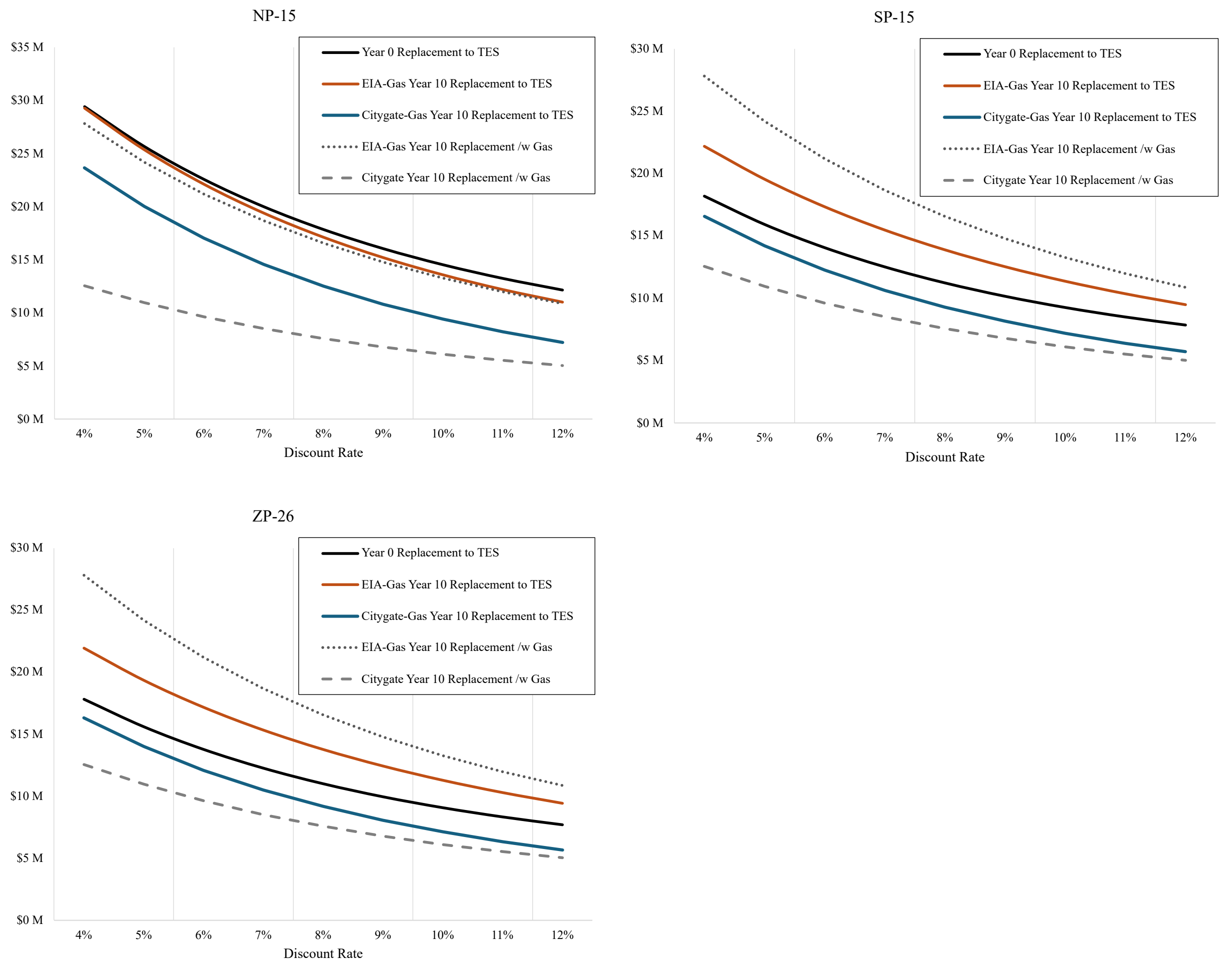
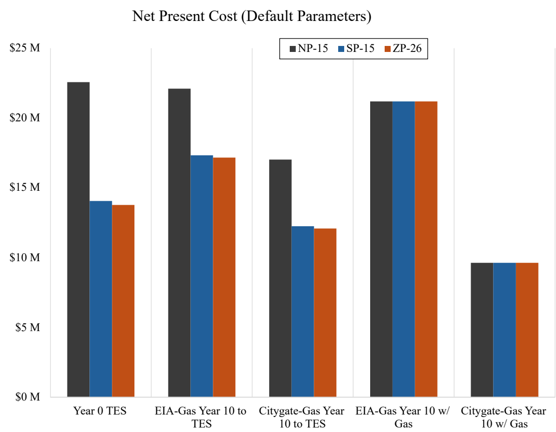


Figure 9. *Charts showing a sensitivity analysis of the net present cost when varying discount rates.*

4.2.2. Negative Electricity Growth Rate, Varying TAC

In a scenario with negative wholesale electricity price growth of 3% (or -3% growth rate), and a natural gas price growth rate of 3%, keeping all other parameters the same, we can see that although electrification becomes more favorable, natural gas remains the cheapest option. In the figure below, the chart on the left is the default scenario and the chart on the right is the negative wholesale electricity price growth scenario. Note that this still assumes a 4% TAC growth rate.



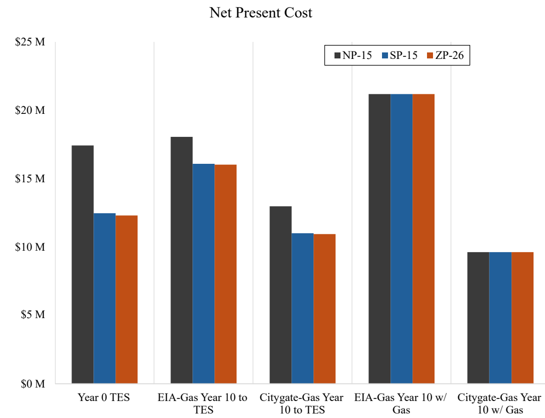
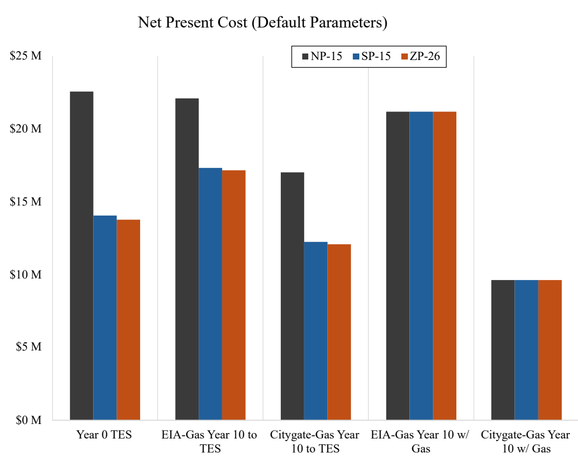


Figure 10. *Charts showing net present cost with default parameters on the left and negative wholesale rate growth on the right.*

However, under the same scenario but with TAC decreasing 1% annually, the two charts below show electrification becomes more economical than natural gas, when paying Citygate rates. Since TAC makes up the majority of the wholesale price of electricity in SP-15 and ZP-26, this shows the importance of understanding future changes in TAC and exploring strategies to reduce it.



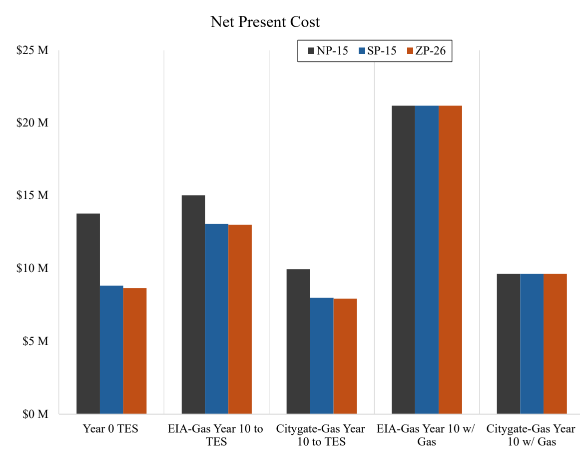


Figure 11. *Charts showing the net present cost with default parameters on the left and decreasing TAC rates on the right.*

5. Recommendations

5.1. Rate Reform

Reward load flexibility through power market pricing. Current retail rates do not adequately reflect wholesale rate dynamics, leading to underconsumption and underutilization of renewables during off-peak time periods. Granting access to low wholesale rates during off-peak times can help encourage electrification while avoiding cost-shifting. The California Public Utilities Commission (CPUC) should work with CAISO, with the approval of FERC, to explore rate design that allows loads to draw power from the transmission system under certain conditions such that they do not significantly drive-up prices or impact the grid.

Additionally, the state energy regulatory agencies in partnership with CAISO should further study grid nodes where there is a combination of high renewable generation, high congestion, low locational marginal prices, and nearby industry. Firms in these locations may be top candidates for adopting thermal energy storage, and the state can help them understand the economics of the transition. Additionally, they should engage with industrial firms in these areas to better understand their cost considerations. Finally, CAISO should study how load growth at specific nodes affects wholesale prices.

CAISO and the California Energy Commission (CEC) should study the costs and benefits of reforming the transmission access charge (TAC). The current rate structure for TAC does not encourage efficient use of the grid, forcing "off-peak consumers to subsidize on-peak consumers", according to a CPUC report.[62] One potential option not studied in this report is to break apart the volumetric charge into a smaller volumetric charge along with a time of use charge. If certain types of load are given access to wholesale prices, then a TAC reform could help encourage off-peak and flexible demand during the cheapest hours of the day. Decreases in TAC that encourage new load that is grid benefiting could have a positive net benefit.

Connecting new industrial load at the low-voltage transmission system may open up more opportunities to transition industrial firms from natural gas to thermal energy storage. Since the low-voltage transmission system is handled by individual utilities and not CAISO, the CPUC should work with utilities to explore rate structures that could help encourage industrial decarbonization, improving grid reliability and avoiding cost-shifting.

[62] Levin, Robert. "Reforming the TAC and Retail Transmission Rates," 11.

Finally, interconnection studies that consider non-coincident load may allow faster integration of resources onto the grid. I recommend working with CAISO to explore ways to interconnect TES and how various constraints on load could simplify the interconnection process.

5.2. Target Industrial Firms Facing Highest Natural Gas Costs

Industrial firms paying core natural gas rates face annual fuel costs more than two times the annual fuels costs using the Citygate price. Although these firms represent a small portion of overall emissions, their higher annual fuel costs make them great candidates for projects that may more easily pencil out. However, given that this analysis assumes a firm is connecting directly to the transmission system, further study is needed to understand where these firms are able to connect to the transmission system and its associated cost. Additionally, moving load off of the core gas system can shift costs to other customers, pushing more customers to leave the system. I recommend the CPUC study ways to shift industrial load to thermal energy storage while reducing cost-shifting to other customers in the core system.

5.3. Engage Public Utilities and Air Districts

Engage with public or municipal utilities on rates that mirror wholesale rates for certain industrial loads. Since these utilities have more flexibility in how they design rates, it may be a simpler process to transition industrial loads in their service area to thermal energy storage. I recommend the CEC provide technical support to these utilities to help them understand how they could transition natural gas industry in their service area to thermal energy storage.

Regional air quality agencies (Air Pollution Management Districts and Air Quality Management Districts) may be interested in providing additional incentives to industrial firms in their areas to shift away from natural gas and reduce criteria pollutants. I recommend engaging with these districts and factoring in any additional incentives into future modeling.

5.4. Additional Analysis

This research modeled a firm with a consistent, daily energy demand. There are many types of demand that can be more flexible, such as seasonal, intermittent, and dual fuel or onsite renewables. By using onsite renewables or leaving existing natural gas infrastructure in place, new industrial loads can fallback to a different "fuel source" when wholesale prices are too expensive or when enrolled in a demand response program. Another option is thermal energy storage that holds 48 hours of capacity and optimizes the cheapest 16 hours over two days or can curtail during peak demand on one day. Further analysis is needed to understand the economics of variable industrial loads.

The electrification scenario in NP-15 is still not cost-competitive with natural gas. Further study is needed to understand why NP-15 experiences higher prices and what options are available to decarbonize industrial load in those areas.

In a time of a growing affordability crisis for retail electricity rates, there are important political concerns around giving industrial customers having special access to cheaper rates. More study is needed to properly design the policy to determine a rate structure that does not create any cost-shifting onto customers who do not have access to wholesale prices.

6. Conclusion

Thermal energy storage offers a pathway to decarbonizing industry in California today. Through rate design that would allow firms to take advantage of periods of low or negative pricing and high curtailment of renewables, firms may be able electrify and fuel their industrial processes at an operating cost similar to using existing natural gas equipment. By taking advantage of California's success in deploying solar throughout the state, considerable opportunities exist to take advantage of underutilized renewable resources and further decarbonization.

Transitioning industrial processes to thermal energy storage systems that operate only during certain hours can help better utilize our existing grid. A recent report from the Nicholas Institute at Duke University found that up to 98 GW of new load could be added to the national grid if it maintained an average annual curtailment rate of just 0.5%. As the report notes, "when new loads are flexible enough to avoid a high coincident load factor, thereby mitigating contribution to the highest-demand hours, they fit within the existing grid's headroom".[63] While this study did not focus specifically on curtailing thermal energy storage, limiting these systems' access to wholesale electricity pricing to off-peak hours could enable significant new load without contributing to system peaks.

[63] By-Nc, Cc. "Copyright © 2025 Nicholas Institute for Energy, Environment & Sustainability,"

Beyond the critical climate benefits of reducing carbon emissions, thermal energy storage (TES) can help support the infrastructure investments California must make to accommodate growing demand from electric vehicles, data centers, and building electrification. Electrifying over 500 billion cubic feet of industrial natural gas use will add significant load to the grid and present numerous challenges. But since grids are built for their peak demand, increasing grid utilization with new off-peak thermal energy storage can help reduce ratepayer costs. If managed effectively, thermal energy storage can be a major contributor to fixed grid costs while strengthening the economics of electrification.

7. Appendix A – CAISO Zones

The locational marginal price data I used was broken up into CAISO zones. The three CAISO zones are NP-15 in the north, and SP-15 and ZP-26 in the south. In modeled annual fuel costs, NP-15 is more than twice as expensive as ZP-26 and SP-15. I did not investigate the reason for this. However, I'm assuming it's due to excess generation from solar in ZP-26 and SP-15, and congestion between those zones and NP-15, making it difficult for cheap renewables to reach load centers.

Figure 12: *A map of CAISO Zones. Source: "OASIS - PRODUCTION - PUBLIC - Apapjbos4392 - 0." Accessed April 20, 2025. https://oasis.caiso.com/mrioasis/logon.do.*

8. Appendix B – Description of Thermal Batteries and Local Companies

8.1. Rondo Energy

According to their website, "The Rondo Heat Battery converts intermittent wind and solar power into a simple, safe, practical, efficient, and affordable supply of continuous industrial heat and power." Their batteries can charge 6-8 hours per day, store at temperatures between 1100-1500°C, and discharge 24 hours a day at over 98% efficiency (in to heat and out to steam).[64] They are based in Alameda, California.[65] The batteries are constructed from refractory brick, which according to their website "has been used for centuries for industrial heat storage, and is made of Earth's most abundant elements: oxygen, silicon, and aluminum. Rondo's breakthrough Heat Battery stores electric power as high temperature heat in refractory brick, without the use of combustibles, critical minerals, toxics, or liquids." Rondo announced a facility with Siam Cement Group to expand manufacturing capacity to 90 GWh per year, up from 2.4 GWh today.[66]

A case study on Rondo's website describes the use of a 2MWh Rondo Heat Battery at a Calgren Renewable Fuels facility in Pixley, California. According to the case study, there wasn't a single hour of plant shutdown when installing the battery. In this case, Rondo integrated their battery into Calgren's existing heat process, allowing Calgren to retain their natural gas system while replacing part of their heat demand with the battery.[67] This case study also mentions they

[64] Note, there is a discrepancy between the maximum temperature on their homepage (1500°C) and the maximum temperatures in their data sheet (1100°C).
[65] "Rondo Energy." Accessed April 24, 2025. https://www.rondo.com/.
[66] "Rondo Energy and Siam Cement Group Plan 90GWh Battery Factory, World's Largest - Rondo Energy." Accessed April 24, 2025. https://www.rondo.com/news-press/rondo-energy-and-siam-cement-group-plan-90gwh-battery-factory-worlds-largest.
[67] "Calgren Renewable Fuels - Rondo Energy." Accessed April 28, 2025. https://www.rondo.com/case-study/calgren-renewable-fuels.

used a heat-as-a-service (HaaS) financing model. Further study is needed to understand how this model works and if it's a viable option for other manufacturing facilities.

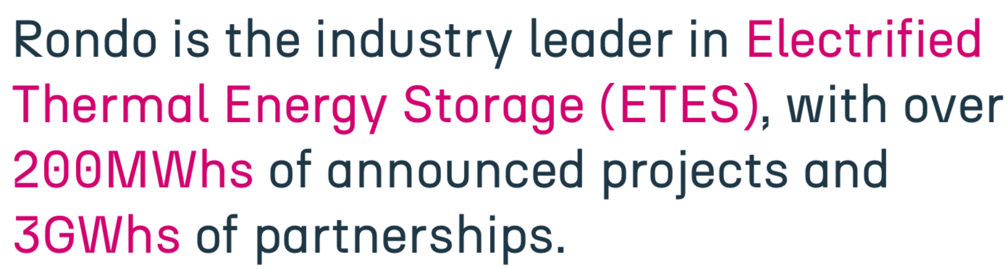


Figure 13: A screenshot from Rondo's website on announced projects and partnerships

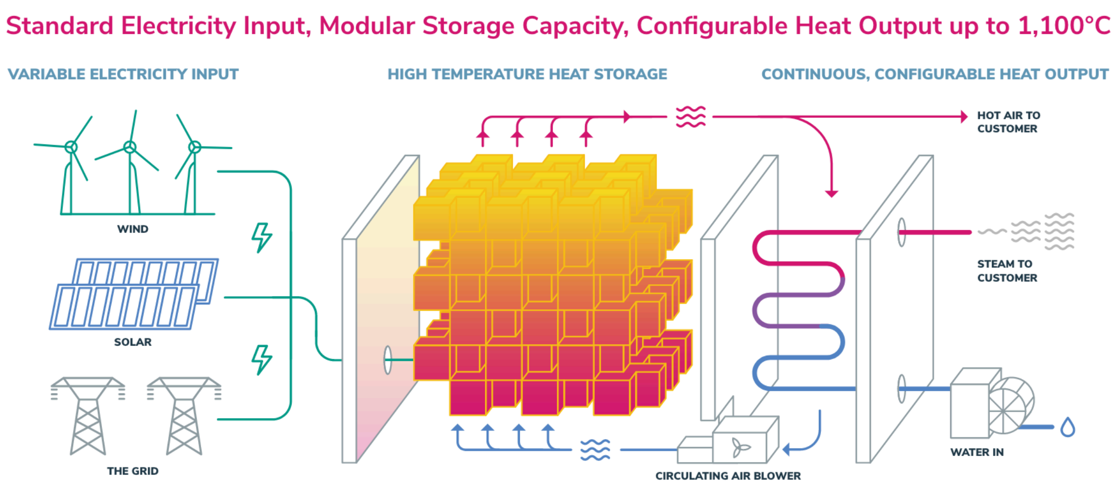


Figure 14: A screenshot from Rondo's Heat Battery data sheet on how the battery works

RONDO HEAT BATTERY TECHNICAL SPECIFICATIONS	RHB100	RHB300
Typical Daily Output	168 MWh	480 MWh
Depth of Discharge	100%	100%
Typical Max. Discharge Rate	7 MWt	20 MWt
Typical Energy Storage Capacity	100 MWh	300 MWh
Typical Peak Charge Rate	20 MW (AC)	70 MW (AC)
Number of Cycles	Unlimited, 40 years	Unlimited, 40 years
Round Trip Efficiency	98%	98%
Discharge Temperature Range	80 - 1100 C	80 - 1100 C
Dimensions	15 (l) x 12 (w) x 12 (h) m	40 (l) x 15 (w) x 12 (h) m

Figure 15: A screenshot from Rondo's Heat Battery data sheet on technical specifications[68]

8.2. Antora

Antora, a company based in Sunnyvale, with a manufacturing facility in San Jose, has also developed a thermal battery for industrial decarbonization. According to their website, they currently have a "Heatcore" battery, that offers temperatures up to 400°C and is available today. They have a "Heatmax" battery, offering temperatures up to 1500°C and a "Combined Heat & Power" battery that are both in development. They currently do not have any case studies listed.[69]

Brenmiller and Malta are two other exciting companies in thermal energy storage not described in this report.

[68] "Download the Rondo Heat Battery Data Sheet - Rondo Energy." Accessed April 28, 2025. https://www.rondo.com/data-sheet-download.
[69] Antora. "Antora – Home." Accessed April 28, 2025. https://www.antora.com//.

HEATCORE

Up to 400°C Heat

Available Today

Antora's modular design allows for flexible deployment based on your energy needs.

STORAGE MODULE

Thermal Output	225 kW_{th} (0.77 MMBtu / hour)
Maximum Charging Rate	700 kW_e
Number of Cycles	Unlimited
Unit Validation	Factory tested

TYPICAL PLANT

Serviceable Heat Load	100 - 400+ °C (210 - 750+ °F)
Typical Design Life	20+ years
Plant Footprint	10,900 kW_{th} / acre (2.65 kW_{th} / m^2)

Figure 16: A screenshot of Antora's website of one of their batteries

9. Appendix C – Comparison of Constrained Hours

I generated the cheapest 4-10 hours per day from CAISO day ahead locational marginal price data. Sometimes the cheapest hour in a day is in the middle of the night and non-consecutive with other hours. This research does not account for battery ramping speed and it's generally inefficient for a battery to turn on to charge for just an hour then turn off. I reran the annual fuel cost model where I constrained the cheapest hours to be between 8am and 6pm. When doing this, there were no non-consecutive hours selected in the set of cheapest hours. In the second table you can see that it had very little impact on annual fuel cost compared to the original results.

Day Ahead LMP

		NP-15		SP-15		ZP-26	
Month	Days in month	$/therm	Total	$/therm	Total	$/therm	Total
Jan	31	$2.57	$191,052.68	$1.62	$120,218.52	$1.83	$136,465.97
Feb	29	$1.04	$77,284.36	$0.44	$32,667.92	$0.45	$33,711.73
Mar	31	$0.92	$68,151.95	-$0.25	-$18,616.37	-$0.31	-$23,348.88
Apr	30	$0.63	$46,904.28	-$0.45	-$33,441.54	-$0.30	-$22,577.36
May	31	$0.45	$33,562.57	-$0.13	-$9,684.00	-$0.18	-$13,132.10
Jun	30	$0.75	$55,628.19	$0.55	$40,739.98	$0.49	$36,376.22
Jul	31	$1.41	$105,075.94	$1.36	$101,212.08	$1.30	$96,982.03
Aug	31	$1.24	$92,162.09	$1.15	$85,354.08	$1.04	$77,353.41
Sep	30	$1.16	$86,182.91	$0.88	$65,784.09	$0.77	$57,253.73
Oct	31	$1.63	$121,540.44	$0.97	$71,886.03	$0.87	$64,606.93
Nov	30	$1.52	$113,148.61	$0.76	$56,348.48	$0.70	$51,871.57
Dec	31	$1.66	$123,403.81	$1.23	$91,171.42	$1.22	$90,797.95
		NP-15 Total	$1,114,097.82	**SP-15 Total**	$603,640.70	**ZP-26 Total**	$586,361.21

Source data is missing for some dates in January and February. To correct for this, I take the average cost of all BHs during that month then multiply by the days in the month. For months where no days are missing this amounts to dividing then multiplying by the number of days in that month.

Constrained between the hours of 8am and 6pm

Day Ahead LMP

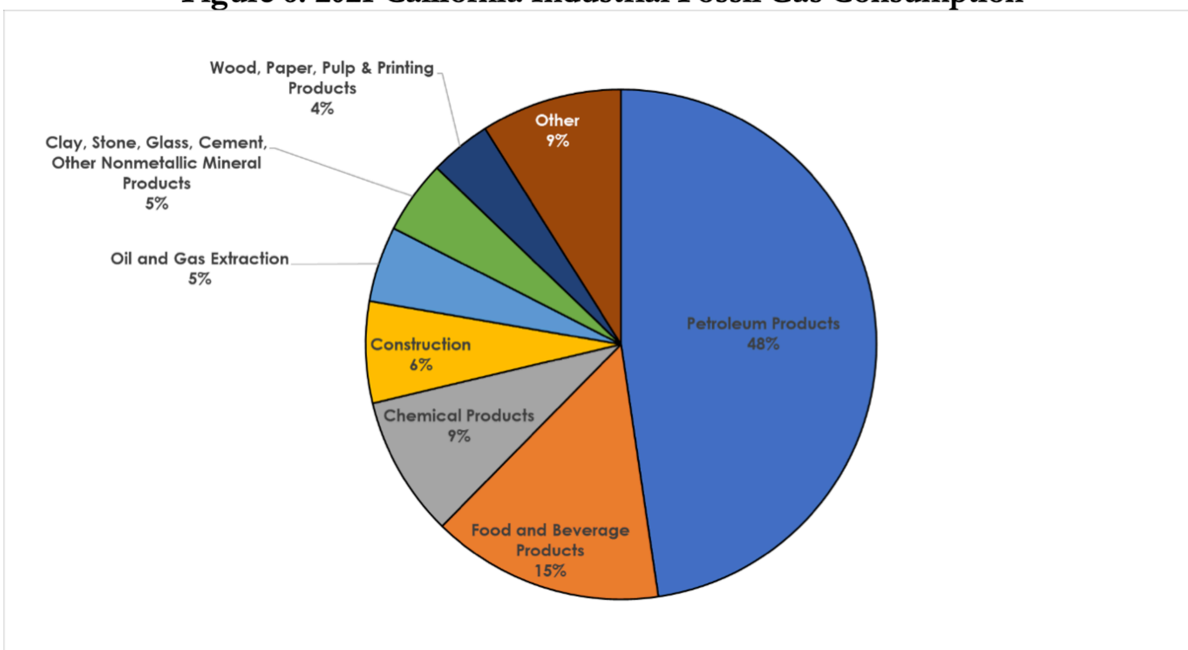
		NP-15		SP-15		ZP-26	
Month	Days in month	$/therm	Total	$/therm	Total	$/therm	Total
Jan	31	$2.68	$199,621.64	$1.64	$121,740.98	$1.86	$138,218.84
Feb	29	$1.06	$78,778.35	$0.45	$33,588.99	$0.47	$34,839.97
Mar	31	$0.93	$68,837.75	-$0.25	-$18,616.37	-$0.31	-$23,348.88
Apr	30	$0.64	$47,524.53	-$0.45	-$33,441.54	-$0.30	-$22,577.36
May	31	$0.45	$33,569.54	-$0.13	-$9,684.00	-$0.18	-$13,132.10
Jun	30	$0.75	$55,628.19	$0.55	$40,739.98	$0.49	$36,376.22
Jul	31	$1.43	$106,437.33	$1.37	$102,021.02	$1.31	$97,332.77
Aug	31	$1.25	$92,645.75	$1.16	$85,995.10	$1.04	$77,516.98
Sep	30	$1.16	$86,480.92	$0.89	$66,262.67	$0.77	$57,377.02
Oct	31	$1.68	$125,347.11	$0.97	$71,924.82	$0.87	$64,615.93
Nov	30	$1.57	$116,729.20	$0.76	$56,605.15	$0.70	$52,118.88
Dec	31	$1.72	$127,740.75	$1.23	$91,502.10	$1.22	$91,119.68
		NP-15 Total	$1,139,341.06	**SP-15 Total**	$608,638.88	**ZP-26 Total**	$590,457.94

Source data is missing for some dates in January and February. To correct for this, I take the average cost of all BHs during that month then multiply by the days in the month. For months where no days are missing this amounts to dividing then multiplying by the number of days in that month.

10. Appendix D: Composition of Industry in California

According to the California joint energy agencies report on transitioning away from natural gas, “About 85 percent of fossil gas used for industrial purposes fuels heating and chemical processes such as high-pressure steam generation, drying, heat treating, curing, forming, distillation, calcining, smelting, and driving chemical reactions. The largest industrial consumers are petroleum refining and oil and gas extraction, which together account for roughly 53 percent of the sector’s demand. Food and beverage industries follow with 15 percent of industrial fossil gas demand”. [70] According to EIA estimates, California industry consumed 676 billion cubic feet of natural gas in 2023.[71]

Figure 6: 2021 California Industrial Fossil Gas Consumption



Source: CEC, Quarterly Fuel and Energy Report (QFER) Database.

Figure 1. *2021 California Industrial Fossil Gas Consumption. Source: California Energy Commission, Quarterly Fuel and Energy Report (QFER) Database, as cited in the Joint Agency Staff Gas Transition White Paper (2024).*

73% of industrial facilities account for only 7% of total industrial emissions, while 4.3% of total facilities, those emitting over 1 million megatons of CO2e per year, account for 57% of

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[70] CPUC, CEC, and CARB, *Gas Transition White Paper*, 2024. 11.

[71] “U.S. Energy Information Administration - EIA - Independent Statistics and Analysis.” Accessed April 20, 2025. https://www.eia.gov/state/seds/data.php?incfile=/state/seds/sep_fuel/html/fuel_use_ng.html&sid=US&sid=CA.

total sector emissions. These larger facilities are likely purchasing natural gas closer to Citygate prices.

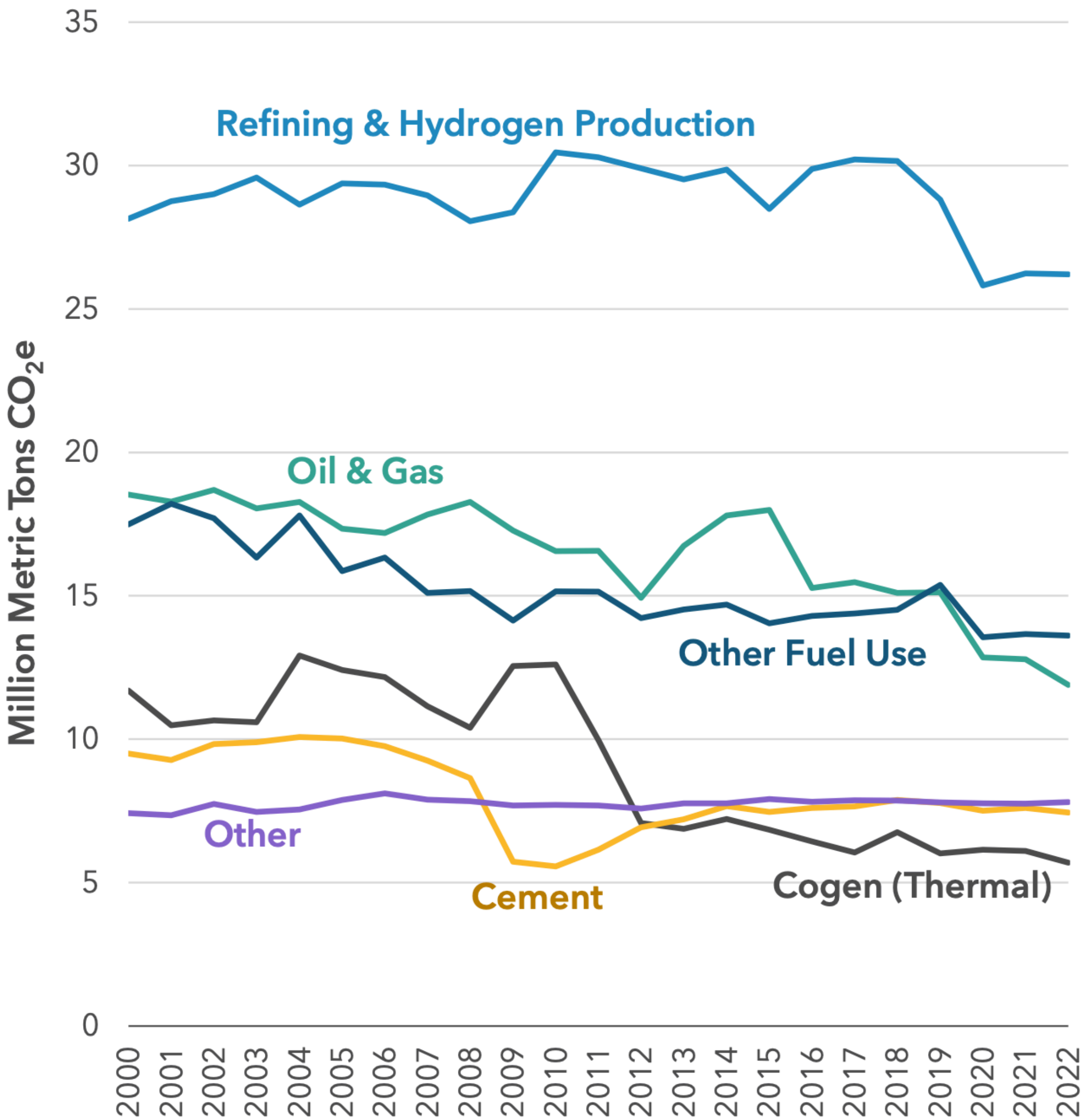

Figure 17. *A chart from a CARB report on California greenhouse gas emissions and trends. Source: California Air Resources Board. California Greenhouse Gas Emissions from 2000 to 2022: Trends of Emissions and Other Indicators. Sacramento, CA: California Air Resources Board, September 20, 2024. https://ww2.arb.ca.gov/ghg-inventory-data.*