Title

Electricity Sector Emissions Leakage in California’s Cap-and-Trade Program

Authors

Bushnell, James

Novan, Kevin

Publication Date

2026-07-01

Energy Institute WP 365

Electricity Sector Emissions Leakage in California's Cap-and-Trade Program

James Bushnell
Kevin Novan

July 2026

Electricity Sector Emissions Leakage in California's Cap-and-Trade Program

James Bushnell, Professor, Department of Economics, University of California, Davis

Kevin Novan, Professor, Department of Agricultural and Resource Economics, University of California, Davis

July 2026

Prepared for the California Air Resources Board and the California Environmental Protection Agency, contract number 22ISD006.

Disclaimer

The statements and conclusions in the Report are those of the contractor and not necessarily those of the California Air Resources Board. The mention of commercial products, their source, or their use in connection with material reported herein is not to be construed as actual or implied endorsement of such products.

Acknowledgement

The authors would like to thank Francisco Pizzi, Jessica Lyu, and Robert Reaser for their outstanding research assistance.

This Report was submitted in fulfillment of Agreement No. 22ISD006, Retrospective Study to Evaluate Electricity Sector Emissions Leakage in the Cap-and-Trade Program by the University of California, Davis under the sponsorship of the California Air Resources Board. Work was completed as of February 14, 2025. Preliminary results of this work were presented at a CARB workshop in October 2025.

Table of Contents

List of Figures

List of Tables

Abstract

This study quantifies the extent to which the reported reductions in emissions from California's electricity imports from 2011 through 2021 have been impacted by emissions leakage in the surrounding western electric grid. This evaluation looks at aggregate outcomes and does not evaluate specific transactions, imports for individual load-serving entities or compliance with regulatory provisions to minimize emissions leakage.

Our empirical analysis presents two complementary estimation approaches. First, we apply marginal emissions estimation methods to quantify the amount of emissions caused by California imports each year and compare multi-year changes in our estimates of the import-driven emissions to the reduction in emissions from imports reported to CARB. Second, we apply an attributional approach to compare trends in the output of reported sources with their observed output overall. Both approaches indicate that Roughly half of the 29.6 MMT reduction in emissions from electricity imports could be construed as leakage.

Executive Summary

California has adopted a series of increasingly ambitious greenhouse gas (GHG) reduction goals over the last 20 years, starting with the passage of the Global Warming Solutions Act (AB 32) in 2006. California's Cap-and-Trade Program for GHG was developed by the California Air Resources Board (CARB) as part of a suite of climate policies developed for implementing AB 32. The program began selling allowances in 2012 and capping emissions of large sources in 2013. It was expanded to cover transportation fuels and the distribution of natural gas in 2015. The GHG emissions associated with the production of electricity serving California load have been covered under the Cap-and-Trade Program (and a set of other climate policies) since 2013.

As part of the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (MRR), firms generating electricity inside of California report their GHG emissions to CARB and entities importing electricity from out of state to serve California load must report electricity imports and associated emissions. Figure displays the annual reported electricity imports coming into California, as well as the emissions attributed to these imports. Relative to 2011, the annual emissions attributed to California's electricity imports in 2021 fell by 29.6 million metric tons – a 58% decline.

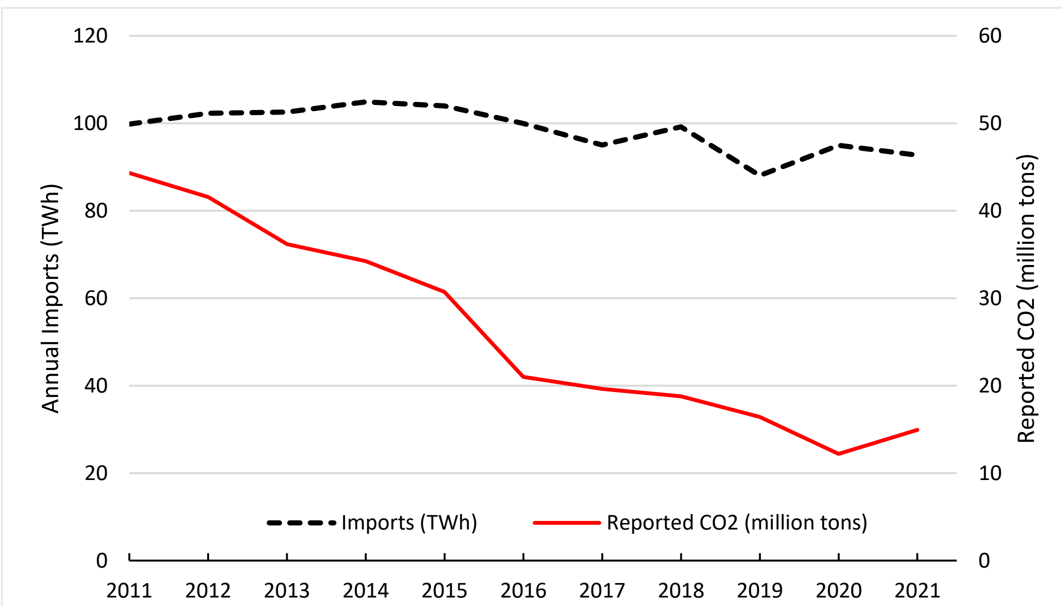

Figure E1: Annual Reported Electricity Imports and Emissions (Source: CARB MRR Data)

AB 32 requires CARB to minimize emissions leakage and defines emissions leakage as a reduction in emissions of GHGs within the state that is offset by an increase in emissions of GHGs outside the state. CARB designed the Cap-and-Trade Program, including its requirements for imported electricity to minimize the potential for emissions leakage while also avoiding conflict with Federal laws and the needs of western power markets. While AB 32 requires CARB to minimize leakage, not all forms of emissions leakage constitute a violation of the Regulation.

The objective of this study is to quantify the extent to which the reported reductions in emissions from California's electricity imports from 2011 through 2021 have been impacted by emissions leakage in the surrounding western electric grid.[1] This evaluation looks at aggregate outcomes and does not evaluate specific transactions, imports for individual load-serving entities or compliance with regulatory provisions to minimize emissions leakage.

Our empirical analysis presents two complementary estimation approaches. First, we apply marginal emissions estimation methods to quantify the amount of emissions caused by California imports each year and compare multi-year changes in our estimates of the import-driven emissions to the reduction in emissions from imports reported to CARB (displayed in Figure).

This first estimation approach largely abstracts from potential longer-run changes in electricity generation capacity that may be caused by California's climate policies. To directly account for these longer-run capacity changes, we apply an attributional approach that examines long-run trends in the generation mix and emissions from both California electricity imports and the broader western electric grid. The purpose is to identify the extent to which the long-run decline in emissions associated with California imports reflect changes in overall western emissions or instead reflect emissions leakage.

To summarize how the resulting estimates of the annual emissions caused by imports have changed since the introduction of the Cap-and-Trade Program, we calculate the difference between the estimated annual emissions during each year relative to the estimated annual emissions attributed to imports in 2011. In addition, we calculate the *change* in the reported annual emissions relative to the reported imported emissions during 2011.

[1] This report is not focused on evaluating emissions leakage from the operation of the western Energy Imbalance Market. CARB has an existing process to address emissions leakage occurring in the WEIM through the calculation of estimated emissions leakage (EIM Outstanding Emissions) and reductions of freely allocated allowances provided to electric utilities.

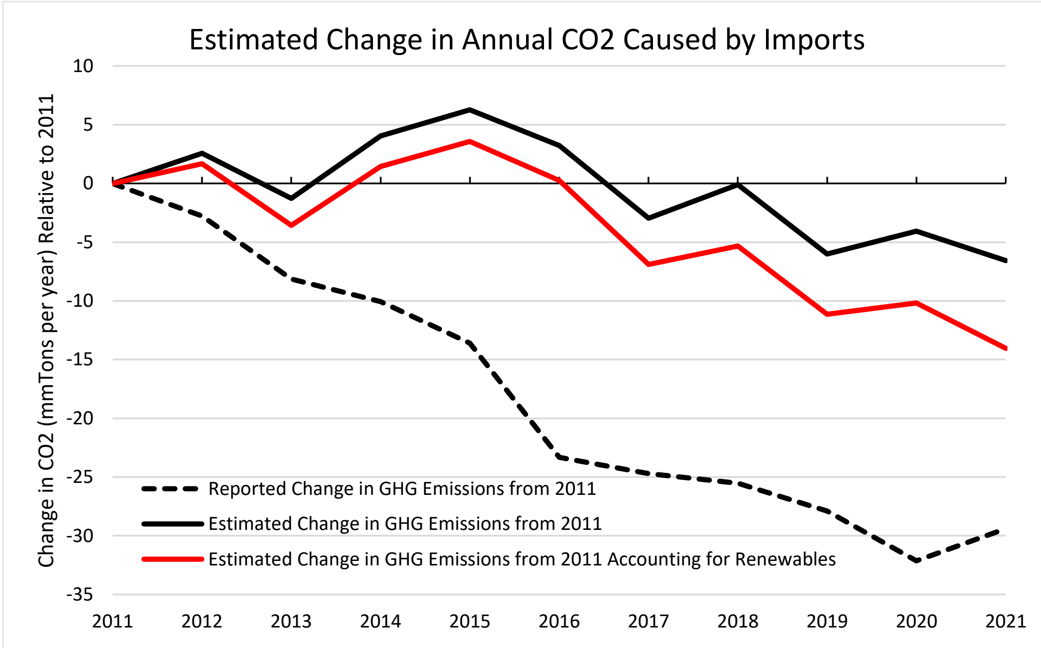

Figure E2: Reductions in Estimated Emissions Relative to Reported Emissions

Under the assumption that the new out-of-state renewable capacity in the reported imports was caused by the Cap-and-Trade Program (the red line in Figure E2), we estimate that the annual emissions attributed to California's imports in 2021 were 15.5 million tons lower than the 2011 emissions caused by California's imports. For comparison, the reported annual emissions attributed to California's imports were 29.6 million tons lower in 2021 relative to 2011 (the dashed line in Figure E2). That is, our estimates displayed by the red line above find that 57% of the reported emission reductions in 2021 relative to 2011 were reached through channels that would not be considered leakage, and that the remaining 43% could be construed as leakage.

Our second approach to estimating the extent of leakage contrasts trends in the energy sources being reported as sources of imports with those of power plants in the western grid overall. One finding is that since 2011, imports from existing zero or near-zero emissions sources such as nuclear and hydroelectric electricity have increased substantially, despite that overall production from those sources has remained flat or decreased during the same period. In other words, there has been a substantial increase in the percentage of output from these sources reported as imported into California since 2011.

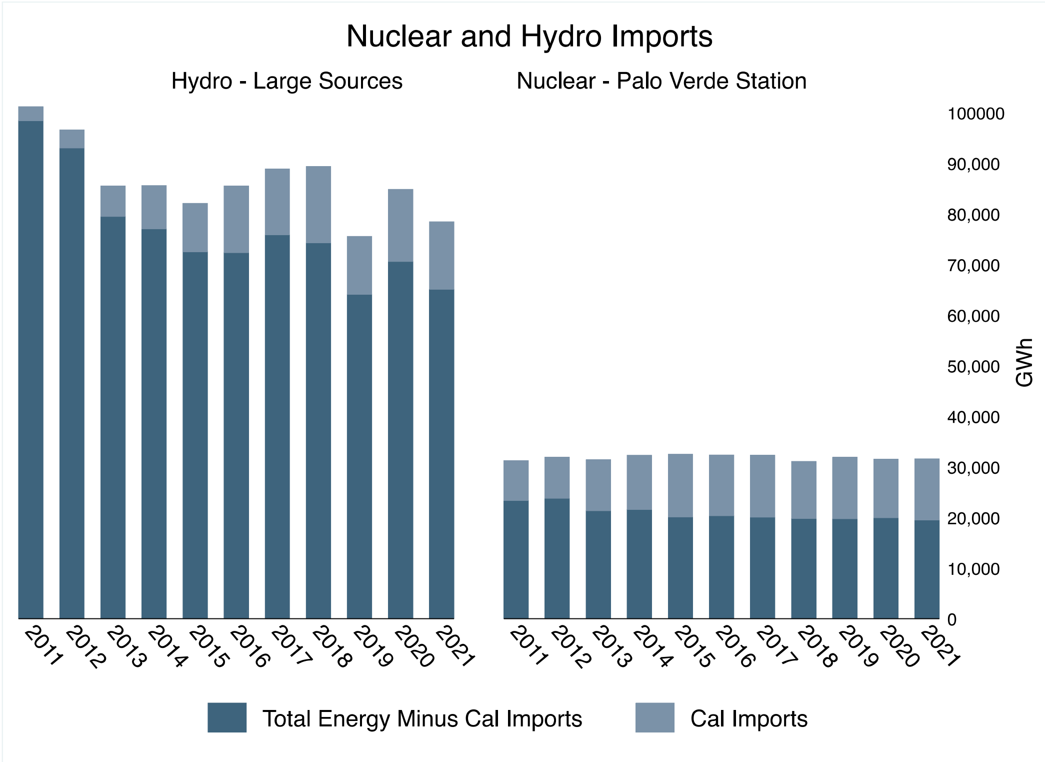

Figure E3: Total Output and Imports from Zero Carbon Sources

We combine several datasets from California and Federal agencies to decompose the sources of reductions in reported imported electricity emissions into 6 main categories, summarized below.

Category	Description	Leakage Risk
Imported TWh volume	*Changes in the quantity of imported energy*	None
New zero carbon	*Imports associated with new zero-carbon capacity*	Low
Retiring Fossil	*Reductions traced to no longer importing from plants with retiring units*	Low
Incumbent Zero Carbon	*Reductions traced to increasing imports from pre-existing nuclear and hydroelectric sources*	High
Incumbent Fossil	*Reductions traced to changes in the mix of fossil plants supporting imports*	High
Renewable Portfolio Standard (RPS) Adjustment	*Adjustments to Cap-and-Trade compliance for renewable energy supporting RPS compliance*	Unclear

Table E 1: Categories of Reductions in Emissions Associated with Electricity Imports

These categories include reductions traced to retirements in coal plants and newly added capacity in renewable energy. We consider these categories likely to represent actual reductions in GHG emissions across the western grid. We also assign a level of emissions reductions to two other categories: increased imports from existing hydroelectric and nuclear sources and reductions in the emission rates of reported imports from thermal sources. It is reasonable to assume that emissions reductions that could be traced to increased imports from existing sources and therefore constitute a form of leakage. While reductions in emissions rates of reported thermal emissions could be attributed to shifts in emissions rates overall, it could also represent leakage through a shift in import sources.

A sixth category assigns reductions associated with the RPS adjustment. This adjustment reduces Cap-and-Trade compliance costs for entities when renewable energy is used for compliance with California's RPS and is generated outside of, but not delivered to, California. The leakage implications of RPS adjustments are difficult to evaluate with the information available to us, but represents a relatively small share, about 6%, of overall reductions between 2011 and 2021for the electricity sector.

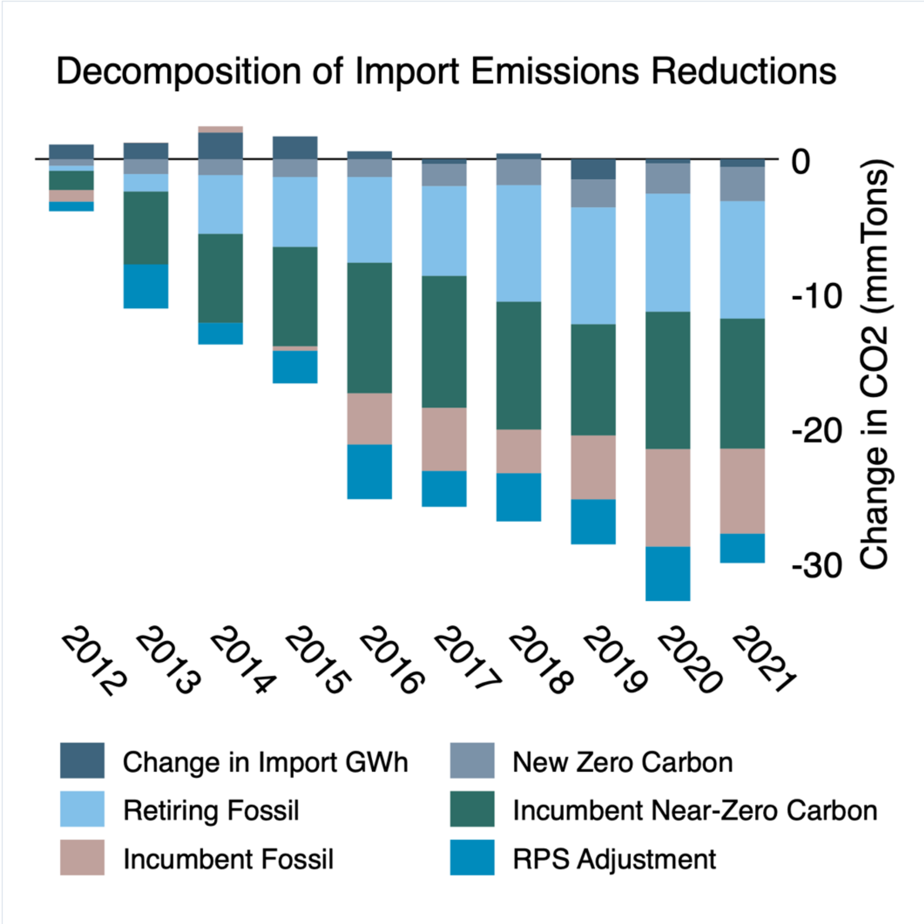

Figure E4: Sources of Import Emissions Reductions

If we consider the first three categories to *not* be leakage and the fourth and fifth categories to likely constitute leakage, we reach estimates similar to those calculated through our econometric approach. Roughly half of the 29.6 MMT reduction in emissions from electricity imports could be construed as leakage.

It is important to note that our analysis, and the summary above, address *aggregate* outcomes. There is an important distinction between aggregate outcomes and specific transactions that might constitute emissions leakage or violate the Cap-and-Trade Program's prohibition on resource shuffling. We are not aware of any evidence that any of these changes constituted activities that violate policies on reshuffling of sources.

These results do indicate that some degree of leakage is possible within the existing regulatory framework. The largest source of implied leakage can be traced to increased imports from existing hydroelectric and nuclear resources.

1. Introduction

One of the great challenges to reducing the emissions of greenhouse gasses (GHG) with local mandates, standards, or emissions caps is mitigating the risk of emissions leakage. Leakage can take several forms, but at a high level it involves the shifting of emissions-creating activity away from jurisdictions regulating GHG emissions toward jurisdictions with less strict, or no, GHG regulations. Various mechanisms have been proposed and implemented to discourage leakage, including border taxes on carbon intensive imports and the output-based subsidization of local industries.

California has adopted a series of increasingly ambitious GHG reduction goals over the last 20 years, starting with the passage of the global warming solutions act (AB 32) in 2006. California's Cap-and-Trade Program for GHG was developed by the California Air Resources Board (CARB) as part of a suite of climate policies developed for implementing AB 32. The program began selling allowances in 2012 and capping emissions of large sources in 2013. It was expanded to cover transportation fuels and the distribution of natural gas in 2015. The GHG emissions associated with the production of electricity serving California load have been covered under the Cap-and-Trade Program (and a set of other policies) since 2013.[2]

AB 32 requires CARB to minimize emissions leakage and defines emissions leakage as a reduction in emissions of GHGs within the state that is offset by an increase in emissions of GHGs outside the state. CARB designed the Cap-and-Trade Program, including its requirements for imported electricity to minimize the potential for emissions leakage while also avoiding conflict with Federal laws and the needs of western power markets. This includes prohibitions against resource shuffling in the Cap-and-Trade Regulation. Resource shuffling is a type of emissions leakage in which there is a plan to substitute lower GHG emission power for higher GHG emission power in order to reduce a compliance obligation for GHG emissions from imported electricity in the Cap-and-Trade Program. The Cap-and-Trade Regulation also includes safe harbor provisions that provide for allowable electricity deliveries that do not constitute resource shuffling.[3] It is important to note that not all forms of emissions leakage constitute resource shuffling or a violation of requirements of the Cap-and-Trade Program.

As part of the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (MRR), firms generating electricity inside of California report their GHG emissions to CARB and entities importing electricity from out of state to serve California load must report electricity imports and associated emissions. Figure displays the annual reported electricity imports coming into California, as well as the

[2] It is important to recognize that California's electric sector is strongly impacted by a suite of environmental and other regulations beyond just Cap-and-Trade. Because of the overlapping nature of these regulations, it is extremely difficult to attribute any specific emissions reductions, or leakage, to any single regulation. The effects we document here are best interpreted as the aggregate impact of this collection of regulations.

[3] Section 95852(b)(2)(A) of the Cap-and-Trade Regulation.

emissions attributed to these imports. Relative to 2011, the annual emissions attributed to California's electricity imports in 2021 fell by 29.6 million metric tons (mmTons) – a 58% decline.

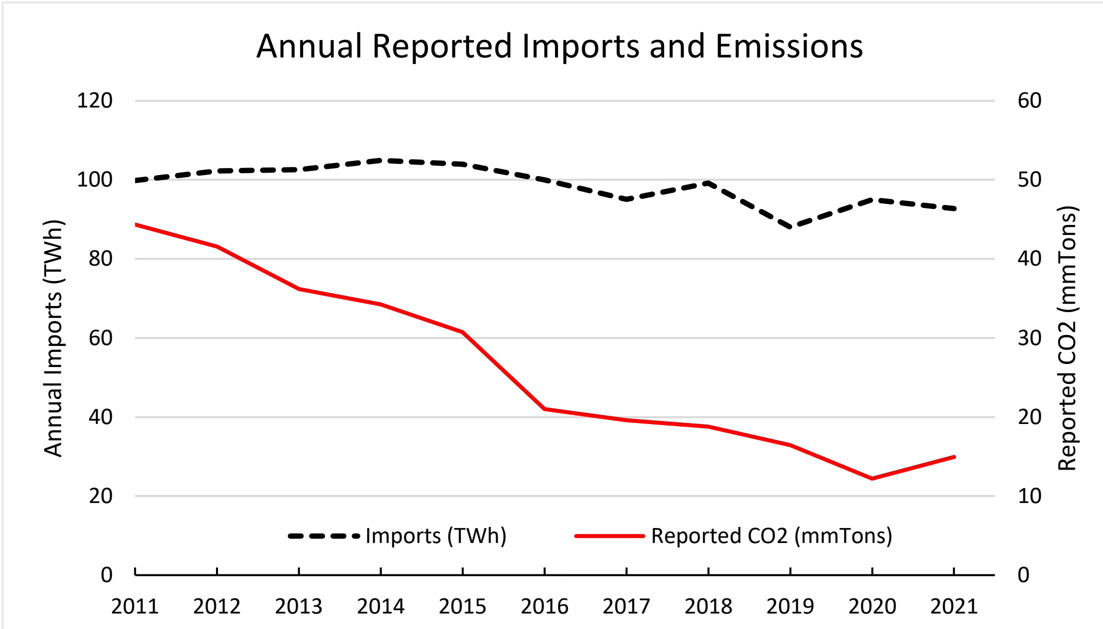

Figure 1: Annual Reported Imports and Emissions (Source: CARB MRR Data)

The objective of this study is to quantify the extent to which the reported reductions in emissions from California's electricity imports from 2011 through 2021 have been impacted by leakage in the surrounding western electric grid. Our empirical analysis presents two complementary estimation approaches. First, we quantify the emissions caused by California imports each year and compare multi-year changes in our estimates of the import-driven emissions to the reduction in emissions from imports reported to CARB (and displayed in Figure). This first estimation approach largely abstracts from potential longer-run changes in electricity generation capacity that may be caused by California's climate policies. To directly account for these longer-run capacity changes, the second estimation approach examines long-run trends in the generation mix and emissions from both California electricity imports and the broader western electric grid. The purpose is to identify the extent to which the long-run decline in emissions associated with California imports reflect changes in overall western emissions or instead reflect an emissions leakage.

Our results indicate that, of the roughly 29 mmTons of annual emissions reductions from electricity imports the market has experienced between 2011 and 2021, about half of those reductions came through channels that could be construed as leakage as defined in AB 32 and as noted above we did not see evidence that these changes constituted activities that violate leakage minimization requirements in the Cap-and-Trade Program. In sections 4 and 5 we develop econometric estimates of marginal emissions rates associated with imports into California and document how those marginal emissions rates have declined over the last decade. This decline, while substantial, is quite a bit lower than the decline in emissions associated with imports reported as part of the Cap-and-Trade Program.

In sections 6 and 7, we combine data from the Program with production records from other sources to evaluate how changes in reported imports compare to changes in production and capacity from similar (or the same) units during the 10 years of our sample. We then apply heuristic formulas to decompose emissions reductions into several channels. Some channels, such as reduction associated with the closure of units at coal plants, we consider to be consistent with actual reductions. Others, such as the increase in imported energy from pre-existing low carbon sources such as hydroelectric and nuclear plants, we consider to be an indication of leakage.

It is important to note that our analysis, and the summary above, address *aggregate* outcomes. There is an important distinction between aggregate outcomes and specific transactions that might constitute emissions leakage or violate the Cap-and-Trade Program's prohibition on resource shuffling. We are not aware of any evidence that any of these changes constituted activities that violate policies on reshuffling of sources. These results do indicate that some degree of leakage is possible within the existing regulatory framework.

2. Background

Leakage in the Electricity Sector

The regulation of emissions from the electric sector posed a set of extremely difficult, if not unique, challenges to California regulators. In 2008, almost 1/3 of the electricity consumed in California was produced in other States, and imports accounted for almost half of California's electricity sector emissions (Bushnell, Chen and Zaragoza-Watkins, 2014). Given the ease with which California can substitute electricity produced out-of-state for in-state production, the setting makes the threat of leakage particularly acute. Intuitively, if an environmental regulation were to exclusively increase the private generation costs for California-based generators, output, and thus pollution, would be expected to immediately increase from the unregulated generators in the surrounding western region. Fowlie (2009) and Bushnell and Chen (2012) both utilize simplified models of the U.S. western electricity market to simulate the impact of a policy that regulates CO2 emissions exclusively from California electricity generators. The simulation results suggest that such a policy would result in substantial leakage, with emissions reductions from in-state generators being almost perfectly counteracted by increases in out-of-state emissions.

Largely due to the prominent role of electricity imports, CARB adopted an approach to regulating electricity sector emissions that is a hybrid of source-based and "downstream" on importers of electricity to California. Emissions from electricity produced inside California are reported at the facility level, similar to the reporting for emissions from all other sources inside the state. Under the Cap-and-Trade Program, the owner or operator of an in-state facility is also required to acquire and surrender compliance instruments (allowances and a limited number of offset credits) equal to its emissions. These California generation operators are considered the "first deliverers" of power into California's grid. The emissions associated with imported electricity is also the responsibility of the "first deliverers" of power into California. However, in the case of imports, the first deliverer may not be the power plant operator, but rather an entity that purchases power from the non-California plant and "first delivers" to the California grid. In this way, entities that purchase power outside of California and import it into the state, either for resale or to directly serve customers, are responsible for identifying the sources of that imported power, if possible, and reporting the emissions associated with that imported power. Under the Cap-and-Trade Program, such entities are also required to acquire and surrender compliance instruments equal to the emissions from those sources associated with the imports.

The adoption of this first deliverer approach to regulating electricity emissions at least partially address the most direct form of emissions leakage that can arise under purely source-based caps, where a plant simply closes in California and its output is replaced by imports from an unregulated plant in a neighboring state.

The first deliverer approach, however, introduces the possibility of other forms of emissions leakage. Many short-term electricity purchases are from exchanges or pools, such as from the market run by the California Independent System Operator or from "system" resources that are not traceable to any specific power plant. Imports from unspecified sources are given a default emissions rate. One concern is that importing firms will convert imports from sources known to be dirtier than these default emissions rates into unspecified resources.

The most prominent vulnerability to a "downstream" regulation such as California's first deliverer policy is the prospect of resource shuffling. Firms that had previously been importing from carbon intensive sources could switch their sources to pre-existing low-carbon sources. If the carbon intensive sources that had previously been selling into California divert their output to other parts of the western electric grid, the net transactions could result in little to no emissions reductions when the full western grid is considered. The reductions to emissions attributed to California imports would be counteracted by a corresponding increase in the emissions associated with consumption outside of California.

Using models that simulate market outcomes in the western electric grid, Bushnell et al. (2014), Xu and Hobbs (2021), and Fowlie et al. (2021) directly model policies that mimic the first deliverer approach. Each of the studies finds that, absent strict non-market barriers to prevent resource shuffling, electricity sector emissions throughout the western U.S. would be effectively unchanged by the adoption of a California Cap-and-Trade Program that applies facility-specific emission factors to quantify emissions attributed to imports (consistent with the first deliverer approach).

While there are numerous simulation-based studies of the potential for leakage and resource reshuffling in regional Cap-and-Trade Programs, there remains little in the way of ex-post empirical estimates of the degree to which leakage is occurring. Focusing on the Regional Greenhouse Gas Initiative (RGGI) cap-and-trade program adopted in the eastern U.S., Fell and Maniloff (2018) utilize a difference-in-difference estimation strategy to quantify the extent to which generation from unregulated electricity producers increased in response to the adoption of the Cap-and-Trade Program. Recent work by Lo Prete, Tyagi, and Xu (2021) employs a similar strategy to quantify how output from electricity generators inside and outside of California changed in response to the adoption of the Cap-and-Trade Program. Using generators from outside of the western U.S. (in the Texas and Eastern interconnections) as potential controls for generators in the western U.S., the authors find evidence, during some periods of the day and during some seasons, of a decline in natural gas generation within California and a corresponding increase in production from fossil units throughout the rest of the western U.S. during the first four years of the program. However, given the first deliverer approach utilized in California's Cap-and-Trade Program, observing a redistribution in fossil output from inside to outside of California does not by itself demonstrate that leakage is occurring.

Regulatory History

Regulators and stakeholders have been acutely aware of the vulnerabilities of the first deliverer system and went through an extensive process from 2010 to 2013 to try to shape policies that could mitigate leakage in the power sector while not causing disruption to the western electricity market. The interstate commerce clause of the U.S. constitution posed another constraint on policy choices. California regulators were sensitive to the risk that policies applied to out-of-state sources could be construed as more restrictive or discriminatory relative to those applied to “domestic” California sources.

Considerations like these contributed to a decision that it would not be possible to, for example, explicitly ban increasing imports from low-carbon existing generation sources outside of California, even if energy from those sources were pre-existing. An effort to discourage reshuffling through more generalized restrictions culminated in a proposed requirement that an agent of first deliverer firms sign, under penalty of perjury, an “attestation” that they would not engage in “any plan, scheme, or artifice to receive credit based on emissions reductions that have not occurred, involving the delivery of electricity to the California grid.[4]”

However, the attempt to enforce such a generalized but opaque set of restrictions was met with broad protest from both industry participants and Federal regulators. Federal Energy Regulatory Commissioner Phillip Moeller issued a public letter arguing that the proposed attestation created significant market uncertainty and threatened electricity market efficiency and, potentially, reliability.

CARB eventually pivoted to different approach. While specific examples of resource shuffling and other “schemes and artifices” were not itemized, CARB incorporated into the Cap-and-Trade Regulation a list of specific actions it would consider to *not* be reshuffling. This set of 13 transaction types constituted “safe harbor” practices that are not pursued by CARB as violations of prohibitions on resource shuffling.[5]

During the same period, there were exploratory discussions about how CARB might penalize entities found to have engaged in the most serious form of resource shuffling, a market driven swapping of ownership in, or long-term contracts with, high carbon sources with long-term arrangements from low or zero-carbon sources.

One possible recourse for CARB that was discussed but, never formally codified or implemented, was to focus penalties on changes to free allowance allocation to California electric utilities. The canonical example would be the sale of a large coal plant that would be replaced by a long-term purchase from a zero-carbon resource, such as a hydroelectric producer. Such a transaction could have triggered a loss of freely allocated allowances to the California utility that was the former owner of the coal plant.

[4] Cullenward and Weiskopf (2013) provide a thorough description of the regulatory process leading up to the adoption of the current rules relating to electricity imports.
[5] Regulation for the California Cap on Greenhouse Gas Emissions, section 95852 (b) (2) (A). https://ww2.arb.ca.gov/sites/default/files/2021-02/ct_reg_unofficial.pdf

Importantly, policies relating to the allocation of emissions allowances are more safely construed to be under California's sole jurisdiction.

One key issue with this approach has been the mismatch between the entities eligible for free allowance allocation and those most directly engaged in importing electricity. Since the start of the program, California electricity distribution utilities (EDU) have received free allocations of emissions allowances to benefit their ratepayers. In 2012 these EDUs, which include investor owned utilities such as Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E), as well as municipal utilities such as LADWP and SMUD, served the vast majority of electricity customers in California. In this sense, the allowance allocation to EDUs principally benefited the retail customers of those same utilities. Conversely, a reduction in allowances allocated to an EDU would directly impact its associated retail operations and customers.

The electricity retail environment in California has shifted substantially due to the rapid expansion of retail service through community choice aggregator (CCA) entities. The large, investor-owned EDUs currently serve a much smaller share of retail electricity customers than in 2012. In this environment the connection between allocation and retail provision is weaker than it was a decade ago. Newly formed CCAs were free to procure energy from existing zero-carbon resources without reshuffling since they had no preexisting "dirty" sources, or sources of any kind, to shuffle out of.

From a system level, however, the net emissions effect is similar to what would have happened if PG&E, SCE, and SDG&E had decided to shed existing import sources and replace them with existing hydroelectric sources. In a sense, customers, rather than out-of-state generation sources, have been reshuffled from investor-owned utilities to CCAs over the last decade.

Ex-Post Quantification of Electricity Sector Leakage

There are two broad approaches to quantifying the emissions associated with goods imported from another jurisdiction and we apply versions of both in this report. The first approach, which we will call *attributional*, links, wherever possible, specific shipments or deliveries to specific sources. The second approach, we will call *marginal*, attempts to measure, while holding all other things constant, the incremental emissions associated with some marginal change to the electric system, such as an increase in imports into California.

Attributional methods are more frequently used in the administration of environmental markets including California's Cap-and-Trade market. This attributional approach is also utilized for imported electricity in Washington State's Cap-and-Invest market and a variant has been proposed for the European Emissions Trading System (ETS). Under these attributional approaches, the importing entity – for example the first jurisdictional deliverer of electricity into California – is responsible for identifying the source of the imported commodity and the emissions associated with production from that source. In most cases, there is a "default" emissions value associated with unknown or unspecified sources. These default emission's rates may be associated with a specific sub-category of product (e.g. corn-based vs. sugar ethanol) or with a particular source region (e.g. the pacific northwest vs. southwestern U.S.).

The second broad approach does not attempt to link a specific source to a specific delivery, but rather attempts to quantify the regional (or global) change in emissions associated with increased production or trade flow. We will call this approach the *marginal emissions rate* (MER) approach. These marginal emissions approaches implicitly assume that production sources operate as an integrated system, and that the commodities in question are fungible to the point that there is no meaningful distinction in the emissions created to supply to different, but similarly located, customers. There are several papers in the academic literature that have applied marginal emissions estimates to a variety of questions, including the impacts of renewable energy production, energy efficiency programs, and electric vehicle charging. For example, Holland et al. (2016) use MER estimates to quantify the impact of charging electric vehicles on emissions from the electric sector. Similarly, Callaway et al. (2018) use MER estimates to quantify the impact of renewable electricity expansions and energy efficiency improvements on emissions from the electric sector. Building on these studies, we provide estimates of how shifts in California's imports from the surrounding WECC region affect CO2 emissions from out-of-state fossil fuel generators.

Beyond the technical challenges of accurate measurement under either approach, each method measures something different. Each has its advantages and disadvantages in the policy context. For example, measures of marginal emissions capture the impacts of short-run, small scale decisions, but may mismeasure the impact of large-scale changes such as the additions of large amounts of new generation capacity. The two approaches therefore can yield substantially different estimates when marginal sources of emissions differ from the average, or infra-marginal sources. For example, in an electric system that is served from 80% baseload nuclear and 20% marginal natural gas production, much (80%) of the load could claim that its consumption is zero-carbon under an attributional approach, but any *increase* in consumption would have to come from natural gas and would therefore not be zero carbon under a marginal emissions rate approach.

Additionally, marginal approaches decouple the emissions measurement from specific procurement decisions. On the one hand this essentially eliminates any incentive to use procurement to reshuffle resources. On the other hand, it also greatly dilutes the reward (at least in the Program) for the procurement of truly new zero-carbon resources since at best such actions might lower the marginal emission rate shared by many importers to California.

With these considerations in mind, we apply both methods in this study. It is important to note that, because of the distinction in measurement approaches, the two methods produce different estimates of overall levels of emissions associated with imports into California for every year, including the years prior to the implementation of the Program. To assess the impact of California's climate regulations since 2012, we analyze the *change* in leakage since 2011 under both approaches. In this case, while the MER approach generates a higher level of emissions than the attributional approach for every year, including 2011, the *decline* in emissions under both approaches over the subsequent decade is comparable, as is our estimate of the contribution of leakage to those measured declines.

3. Data Sources

In this report, we draw upon data from a variety of California and Federal sources. In this section we provide a brief overview of each of the key data sources we utilize.

Mandatory Reporting Regulation and Emissions Inventory

The California Air Resources Board (CARB) produces two main datasets summarizing emissions activity associated with plants both inside and outside of California. The Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (MRR) data collects the emissions data that underpins compliance with the Cap-and-Trade Program. Data from the MRR date from 2011. The emissions inventory (EI) data date back to 1990. Methods for compiling the EI have evolved over the last 15 years and are now reconciled with the MRR for 2012 and later data years.

The EI data include many out-of-state individual power plants when the generation from those plants are identified as sources of electricity imports to serve California. In some cases, sources are either "unspecified," referring to system level purchases, or "primarily hydropower," referring to system level purchases from systems whose energy production is dominated by hydropower. The EI data further provide, for the same sources, the amount of electricity (MWh) imported from those sources. These data also contain the quantity of energy imported from sources with no GHG emissions and therefore provide a complete picture of annual energy imports from both sources with Cap- and-Trade Program compliance obligations as well as zero-GHG sources.

The RPS adjustment recognizes investments in out-of-State RPS-eligible electricity that is not directly delivered to California by adjusting the compliance obligation under the Cap-and-Trade Program. The RPS adjustment is voluntary, and it is only applicable when the importer purchases both electricity and renewable energy credits (REC) together and can demonstrate that the electricity was not delivered to California. The magnitude of this RPS adjustment has fluctuated between roughly 2.5 mmTons and 6.5 mmTons per year. Between 2011 and 2021, the RPS adjustment increased by roughly 2.6 mmTons to a value of 4.7 mmTons.

Recall, Figure displays California's annual electricity imports (reported in the EI dataset) as well as the annual emissions reported from these imports (MRR data). These data are reported from 2011, two years prior to the Cap-and-Trade Program taking effect. Figure 2 summarizes the emissions associated with imported electricity ("import emissions"), broken out by the fuel category of the source of the imports. In the decade between 2011 and 2021, import emissions declined from around 45 million metric tons (mmTons) to just under 15 mmTons per year. These totals include the emissions associated with the RPS adjustment illustrated in Figure 2. Before applying the RPS adjustment, import emissions in 2021 were just under 20 mmTons. Figure 2 also includes the additional estimated emissions associated with operation of the Western Energy Imbalance Market (WEIM) known as the EIM "outstanding emissions." These are emissions that are not fully accounted for from the resources selected by the WEIM to serve California load. This value has historically been a small fraction of overall emissions associated with imports, but has been growing over time, rising to 1.2 mmTons in 2021.

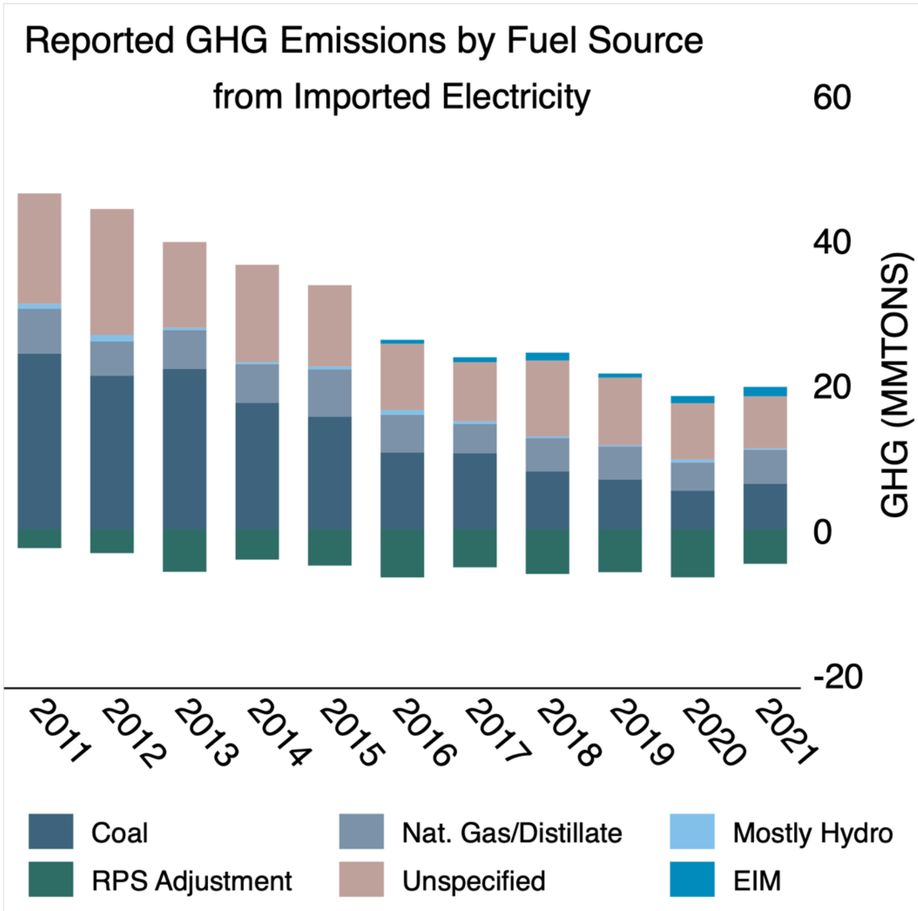

Figure 2: Annual Emissions Associated with Imported Electricity

California Energy Commission Power Source Disclosure Program

The California Energy Commission's Power Source Disclosure Program (PSDP) requires retail electricity suppliers to provide the generation mix used to meet customer demand on an annual Power Content Label (PCL). Suppliers offering multiple electricity portfolios must distinguish between the mix used in each portfolio. We combine all available PSD reports available from 2014 through 2022, allowing us to track the changes to the generation mix and portfolio offerings of California LSE as well as the entry and exit of LSEs.

The PSDP information provides a sense of the overall generation mix of different LSEs and allows us to track trends in, for example, renewable, hydroelectric, and nuclear energy procurement. However, the

PSDP data do not distinguish between energy sources inside of California and imported sources. As we discuss below, we are not aware of a data source that links imported electricity to specific LSEs.

Energy Information Administration Form 930, Form 923, Form 860, and Form 861

The Energy Information Administration (EIA) publishes two datasets that we use extensively in this report. The EIA form 930 includes hourly data at the electricity balancing area authority (BAA) level. A BAA is the party responsible for maintaining reliable electricity system operations within its operating footprint. There are roughly two dozen BAAs in the western grid ranging from large operators such as the California Independent System Operation (CAISO) and the Bonneville Power Administration (BPA) to small utilities such as Seattle City and Light. Since 2018, each BAA has reported via form 930 hourly system level total demand and generation by fuel source, including hydroelectric, wind, and solar. The form 930 also collects hourly net exports/imports to each neighboring BAA. Between July 2015 and 2018, the form 930 included hourly data on only aggregated demand, generation, and system level net exports/imports. To obtain the hourly demand at the balancing area level prior to July 2015, we collect this information from the FERC form 714, described below.

In addition to the EIA form 930 dataset, the EIA form 923 reports monthly energy production from almost every major grid connected power plant in the U.S. The EIA form 923 also reports changes in operating characteristics of power plants, most notably changes to operating status (e.g., retirement) and changes in the rated capacity of plants.

The EIA form 860 annually collects generator-level information about existing and planned generation units at plants with 1 MW or greater combined nameplate capacity. We use this dataset in conjunction with form 923 to determine changes to plant-level operating capacity through either retirement or new construction. The annual EIA form 860 release includes the year and month a unit begins operation and retires, if applicable. This form also includes other relevant characteristics such as nameplate capacity, the generating unit's technology, and its primary and secondary energy sources.

The EIA Form 861 provides annual data on sales (in megawatt hours) to ultimate customers by load serving entities. Form 861 provide classifications by retail entity type (e.g. "investor owned," "retail power marketer," "community choice aggregator") and customer class ("commercial," "residential," "Industrial") that allow us to examine aggregate relationships.

Federal Energy Regulatory Commission Form 714

The Federal Energy Regulatory Commission (FERC) publishes its Form No. 714 - Annual Electric Balancing Authority Area and Planning Area Report - in various forms dating back to 1993. Some elements of the Form 714 overlap with those contained the EIA form 930, which began in July 2015. We utilize Form 714 for parts of our study that encompass the period before form 930 data are available. All balancing authority areas (BAA) with a peak demand greater than 200 MW must file the hourly data provided in Part III of the Form. The key elements of the Form 714 we utilize are the hourly demand, generation, and interchange by BAA.

US Environmental Protection Agency's Continuous Emissions Monitoring Systems

The U.S. Environmental Protection Agency's Continuous Emissions Monitoring Systems (CEMS) records the hourly gross generation and CO2 emissions from nearly the full universe of fossil fuel electricity generators in the U.S. To convert the observed hourly gross generation data to hourly net generation (i.e., the output that is actually supplied to the grid), we compute quarterly net-to-gross ratios. To do so, we utilize data from the EIA's form 923 dataset, which reports monthly net generation.

In order to merge net generation from EIA form 923 with gross generation from CEMS, we need to compare output over comparable time frames and plant footprints. We first aggregate hourly CEMS gross generation and monthly EIA form 923 net generation to the quarterly level. Unfortunately, while both CEMS and form 923 report values at the plant level, output at the subplant (e.g., "unit" or "generator" level) is divided differently in the two datasets. We therefore aggregate output at the subplant level by "prime-mover" (e.g., steam or gas turbine) and primary fuel. Both datasets allow for aggregation at this level, which we refer to as a "triplet" identifier containing the plant ID, the prime-mover, and the primary fuel. A triplet in some cases will be a single unit at a plant; in other cases it will be a combination of units with similar technology (e.g., steam) and fuel (e.g., natural gas).

Dividing the quarterly net generation by the quarterly aggregate gross generation (from the CEMS data) at the triplet level yields a quarterly net-to-gross ratio for each triplet. Multiplying the hourly gross generation reported in the CEMS data by the corresponding net-to-gross ratio yields an estimate of the hourly net generation for each triple.

To provide evidence that (A) our net-to-gross procedure yields reliable estimates of the net generation from non-CA WECC fossil units and (B) the EPA CEMS dataset is not missing a meaningful share of non-CA WECC fossil generation (and thus emissions), we calculate the mean hourly net generation from natural gas units and coal units in the two datasets over the period from July 2018 through December 2022. The first two rows of Table 1 highlight that the mean net-hourly generation is very similar across the two data sources. In addition, the final row of Table 1 highlights that the hourly time series of non-CA WECC generation from natural gas units or coal units are very highly correlated.

Table 1: EIA-930 and EPA CEMS Comparison

	Non-CA WECC Mean Hourly Net Generation	
Source	Natural Gas (MWh)	Coal (MWh)
EIA 930 Dataset	15,003	13,427
EPA CEMS Dataset	14,750	13,426
Correlation	0.97	0.94

Note: The top row displays the mean aggregate hourly net generation reported in the EIA 930 dataset from natural gas and coal generators in the non-CA WECC balancing areas from July 2018 through Dec. 2022. The second row displays the mean of the estimated hourly net generation aggregated across natural gas and coal generators reporting in the EPA CEMS dataset over the same non-CA WECC balancing areas and time period. The final row displays the correlation across the two hourly natural gas and two coal time series.

We also utilize data on the 5-minute level net generation by fuel source (spanning 2011 through 2022) from the California Independent System Operator (CAISO). In addition, from 2018 to present, we also utilize information on the 5-minute level of wind and solar output curtailed in CAISO.

4. Causal Estimates of Imports on Out-of-State Emissions

Empirical Strategy

The foundational metric we develop in this analysis is the marginal CO2 emissions associated with energy imports into California from other parts of the western U.S. Conceptually, this analysis asks, "when another MWh of electricity is imported into California, how much do total CO2 emissions in the non-California west increase?" Since the answer to this question is constantly fluctuating, we are technically estimating the average marginal change in emissions associated with California imports.

Intuitively, if California's impact on emissions from out-of-state electricity generators is solely driven by the amount of electricity being imported into California, then we can quantify leakage by comparing the decline in the estimated emissions caused by California's imports to the decline in reported emissions attributed to California's imports (Figure). It is important to note that, if the adoption of California's Cap-and-Trade Program fundamentally altered the dispatch order of fossil fuel units outside of California, then the Cap-and-Trade Program will cause changes in non-CA emissions that will not be captured by our estimates of the average marginal impact of imports on emissions. For example, if the Cap-and-Trade Program has caused non-CA coal units to move up the dispatch order, and operate less frequently, and cleaner natural gas units to move down the dispatch order, and operate more frequently, then holding the level of imports constant, the aggregate amount of non-CA emissions would decrease as a result of the Cap-and-Trade Program. This decline in emissions would not be reflected in our subsequent estimate of how non-CA emissions change when imports into California change. As a preliminary step in our empirical analysis, we first examine whether there is evidence of systematic changes in the dispatch orders among the fossil fuel generators in the WECC regions surrounding California (AZNM, NWPP, and RMPP).

To examine whether the Cap-and-Trade Program induced changes in the dispatch order among non-CA generators, we test whether the capacity factors of coal units (which have relatively high CO2 emission rates) systematically decrease relative to the capacity factors of natural gas units (which have relatively lower CO2 emission rates) following the adoption of the Cap-and-Trade Program. Importantly, we find no evidence of a systematic change in the dispatch order of coal and gas units in any of the non-CA WECC regions. In particular, after controlling for the fuel prices, we find no evidence of natural gas units' capacity factors increasing relative to the capacity factors of coal units. The results from this preliminary dispatch analysis are discussed in greater detail in the Appendix. The result from this preliminary dispatch analysis suggest that the California's impact on out-of-state emissions can be fully captured by quantifying how out-of-state emissions are affected by imports into California.

Ideally, we would be able to directly measure how changes to imports into California affect the amount of CO2 emitted outside of CA each year. However, there are several challenges that we must confront. First, we are constrained in terms of the availability of several of the key variables that are required to directly identify how shifts in imports affect CO2 outside of the state. In particular, prior to its inclusion in the EIA form 930 in 2018, there are no publicly available data on the hourly generation from non-fossil sources (outside of the CAISO footprint). Instead, this information was only uniformly collected and reported at the monthly level. As our results will highlight, it is crucial to control for the level of renewable production outside of CA in order to accurately identify how shifts in imports into CA affect non-CA WECC CO2 emissions.

In addition to the data constraints, we must also account for the fact that increases in California imports are in part met by contemporaneous increases in out-of-state hydroelectric generation. This can bias estimates of the total emissions impact of California imports downward. Intuitively, the aggregate amount of electricity generated by hydroelectric units over the long-run is dictated by the level of water available, not market demand in California. Moreover, unlike other resources where the output is intermittent (e.g., wind and solar), increasing hydroelectric output in one period will result in less hydroelectric generation available in a future period. Consequently, for each MWh of out-of-state hydroelectric supplied to California, there will be a corresponding 1 MWh *reduction* in the amount of potential hydroelectric generation that can be produced during other hours – leading to a corresponding *increase* in the required generation from non-hydroelectric dispatchable sources during other periods. The implication is that, when the output from hydroelectric plants is used to meet demand in California in any given hour, this can raise total emissions in some future hour that will consequently have less hydroelectric energy available to meet demand. If any of this increase in required generation comes from out-of-state fossil fuel units, then the imports into CA will cause a non-contemporaneous change in CO2 as well. To quantify the full impact of CA imports on out-of-state emissions, we must also estimate these non-contemporaneous emission impacts.

To address these two challenges (i.e., the data constraints and the potential non-contemporaneous impacts of imports), our empirical analysis proceeds as follows. Focusing first on the period with full data coverage (July 2018 – December 2022), we present direct causal estimates of how shifts in the daily level of imports into CA affect the contemporaneous level of CO2 emitted outside of the state as well as the contemporaneous level of hydroelectric generation outside of the state. Using the direct estimate of the share of imports met by out-of-state hydroelectric generation, we introduce an approach to quantify the non-contemporaneous impact of imports on emissions (i.e., for each MWh of imported hydroelectric, we estimate how much out-of-state emissions increase at a different point in time).

Second, using this estimate of the aggregate impact of imports on out-of-state emissions as our benchmark for the 2018-2022 period, we introduce a Marginal Emission Rate (MER) approach that allows us to estimate the annual emissions caused by CA imports each year. Importantly, this MER approach can be implemented using the data that is observed going back to the introduction of the Cap-and-Trade Program. To validate this new approach, we compare the resulting estimates of the emissions caused by imports to the direct, causal estimates. Finally, to quantify leakage, we compare our estimates of the change in emissions caused by California imports from 2011 to present to the drop in reported emissions. Our MER approach serves as an upper bound on the level of leakage, and we also present an estimate of the lower bound of the level of leakage.

Empirical Specification

To identify the contemporaneous impact of California's daily imports on CO2 emissions outside of California, we estimate how the aggregate daily CO2 emitted by fossil fuel generators outside of California responds to shifts in the daily level of gross imports into California. To do so, we estimate the model specified by Eq. 1 below:

$$Emissions_d = \beta^{cont} \cdot Imports_d + \boldsymbol{\theta}_{m,y} \cdot \boldsymbol{X}_d + \alpha_{m,y} + \epsilon_d \tag{1}$$

where $Emissions_d$ represents the total CO2 emitted (in metric tons) on day d from non-CA WECC fossil units in the EPA CEMS dataset and $Imports_d$ are the total gross transfers (in MWh) into California on day d reported in the EIA form 930 dataset. The key coefficient of interest, β^{cont}, represents the average contemporaneous change in the amount of out-of-state CO2 emitted in response to a 1 MWh increase in gross imports into California. It is important to note that this coefficient will not capture any non-contemporaneous impacts of shifts in daily imports on out-of-state emissions. For example, if an increase in imports affects the contemporaneous level of potential energy stored (e.g., by affected out-of-state hydroelectric generation or battery storage), then there would likely be non-contemporaneous impacts of shifts in daily imports on out-of-state emissions. Similarly, if shifts in imports cause longer-run capacity changes (e.g., retirements of out-of-state coal units or renewable capacity additions outside of California), then this will not be reflected in β^{cont}. These dynamic, or non-contemporaneous, emission impacts will be estimated (or bounded) in the subsequent analyses.

There are several threats to identifying an unbiased estimate of β^{cont} from Eq. 1. To begin, shifts in the level of gross imports into California can certainly be correlated with a number of other drivers of out-of-state fossil generation, and thus emissions. To control for potential spurious correlation between seasonal patterns or trends in imports and emissions, we include a set of month-by-year fixed effects ($\alpha_{m,y}$). In addition to the regular seasonal patterns, day-to-day variation in out-of-state emissions will also be driven by fluctuations in out-of-state demand and intermittent renewable output. To account for the fact that these drivers of out-of-state emissions may also be correlated with imports into California, we directly include the daily out-of-state electricity demand (the daily MWh consumed in the Northwest and Southwest WECC regions combined), as well as the daily out-of-state solar output (MWh) and daily out-of-state wind output (MWh) in the vector of controls ($\boldsymbol{X}_d$) in Eq. 1. To flexibly allow shifts in out-of-state demand and renewable output to affect emissions differently over our sample period (e.g., as fuel price change or as the mix of installed capacity changes), we allow the vector of coefficients ($\boldsymbol{\theta}_{m,y}$) on the controls to differ by each month-by-year. In the model specified by Eq. 1 above, ϵ_d represents the unobserved error term – i.e. the remaining, unexplained variation in the daily level of emissions.

Even with the rich set of controls included in Eq. 1, there remains a threat that other shocks to out-of-state supply can simultaneously affect imports into California as well as emissions from fossil units outside of California. For example, if an out-of-state nuclear unit is taken offline for maintenance, then we may expect an increase in emissions outside of California as well as a reduction in imports into California. To address this potential source of endogeneity, we use an instrumental variables estimation approach, two-stage least squares (2SLS). To first identify variation in the daily level of imports into California that are exogenous to unobserved, out-of-state supply shocks, we estimate the first-stage model specified below:

$$Imports_d = \boldsymbol{\gamma} \cdot \boldsymbol{Z}_d + \boldsymbol{\omega}_{m,y} \cdot \boldsymbol{X}_d + \mu_{m,y} + \varepsilon_d \tag{2}$$

where $\boldsymbol{Z}_d$ is a vector of three excluded instrumental variables. In particular, we use the daily level of demand in California (MWh), as well as the daily level of potential California solar generation (MWh) and potential California wind generation (MWh) as the three excluded instruments. The potential solar and wind generation are simply equal to the aggregate daily output from solar or wind (reported in the EIA form 930 dataset) plus any curtailed CAISO solar or wind (reported by CAISO). By adding the curtailed energy back into the potential generation instruments, we are left with three drivers of imports that are effectively exogenous (in the short-run) to market conditions and out-of-state supply shocks. To identify an unbiased estimate of β^{cont} from Eq. 1, the predicted (fitted) level of the daily imports ($\widehat{Imports}_d$) from the first stage (Eq. 2) are used to estimate Eq. 1.

Contemporaneous Impact of Imports

Column (1) of Table 2 below displays the estimate of β^{cont} from Eq. 1, the average contemporaneous increase in daily non-CA WECC emissions in response to a 1 MWh increase in gross California imports. On average, an additional MWh of daily imports causes out-of-state CO2 emissions to increase by 0.468 metric tons on the same day. We find that this point estimate is robust to a variety of alternative specifications – e.g., column (3) of Table 2 presents the estimates with a much simpler set of fixed effects (FE) (month and year FE, not month-by-year) as well as with $\boldsymbol{\theta}_{m,y}$ restricted to be constant across each sample month). In addition, we find that there is little evidence of heterogeneity in the impact of imports across the range of observed daily imports. In particular, column (2) presents estimates with the inclusion of an additional independent variable – the square of the demeaned daily level of gross imports. The fact that there is little evidence of non-linearity suggests that the aggregate contemporaneous impact of imports on emissions can be estimated as the product of the average linear effect and the level of total gross imports. We will utilize this fact later to estimate the total impact of imports on emissions over the period being examined.

Table 2: Change in Daily Non-CA Emissions (metric tons CO2/MWh)

Independent Variable	(1) 2SLS Full Controls	(2) 2SLS Full Controls	(3) 2SLS Limited FE	(4) 2SLS No Renewables	(5) OLS Full Controls
$Imports_d$	0.468**	0.483**	0.468**	0.759**	0.277**
	(0.047)	(0.071)	(0.079)	(0.085)	(0.034)
$Imports_d^2$	·	0.000	·	·	·
		(0.000)			
N	1,394	1,394	1,394	1,394	1,394
R^2	0.976	0.961	0.911	0.910	0.978
Year-by-Month FE	Yes	Yes	No	Yes	Yes
Year & Month FE	No	No	Yes	No	No
Non-CA Demand	Yes	Yes	Yes	Yes	Yes
Non-CA Renewables	Yes	Yes	Yes	No	Yes

Note: Each column presents estimates of the coefficient(s) on Gross CA Imports from the general model specified by Eq. 1 using daily observations from July 1, 2018 through Dec. 31, 2022. Columns (1) through (4) are estimated using two-stage least squares, with the first stage specified by Eq. 2. In column (2), Eq. 1 and Eq. 2 are augmented to include the square of the daily (demeaned) gross imports. The model displayed in column (3) is estimated using uninteracted month and year FE, and the coefficients on the three continuous controls (non-CA demand, solar, and wind) are not allowed to vary by month or year. Column (4) presents the estimate of the impact of gross imports excluding the non-CA solar and wind controls. Finally, column (5) presents the OLS estimate of the impact of gross imports. For each coefficient, standards errors robust to clustering at the week-of-sample level are reported in parentheses. * = signficant at the 5% level; ** = signifcant at the 1% level.

The final two columns of Table 2 point to the importance of two key features of our empirical strategy. First, column (4) highlights that, if we simply estimate the model using ordinary least squares (OLS), abstracting from the potential endogeneity arising from out-of-state supply shocks simultaneously affecting out-of-state emissions and imports into California, then we meaningfully understate the impact of imports on emissions. Second, when we attempt to estimate the impact of imports on emissions without controlling for out-of-state renewable production (column (5) of Table 2), we find that we meaningfully overstate the contemporaneous impact of imports on emissions.

This is a key issue that we must confront in the analysis of our early period, given the data constraints that we face. In particular, recall that we don't have out-of-state renewable generation data at the hourly or daily level prior to July 2018. Consequently, we will need an alternative estimation approach to quantify the impact of imports on out-of-state emissions in the early stages of the Cap-and-Trade Program. In the subsequent section, we introduce our alternative 'data-constrained' estimation procedure. To validate the alternative approach, we will compare the estimates of the emission impacts to the reduced-form causal estimates presented in the current section.

In addition to estimating the contemporaneous impact of imports on emissions, we also re-estimate the model specified by Eq. 1 using the daily net non-CA WECC generation from various fuel sources as the dependent variable. This additional analysis of the generation impacts serves as a way to test whether the empirical strategy is uncovering an unbiased estimate of the impact of imports. Intuitively, if imports into California increase by 1 MWh, then there should be a corresponding 1 MWh increase in out-of-state generation from the combination of dispatchable sources. To test whether this is the case, we re-estimate Eq. 1 using the total daily net generation from non-CA WECC gas, coal, nuclear, hydroelectric, and 'other' sources (observed from the EIA 930 dataset). Column (5) of Table 3 displays the resulting point estimate of 1.038 MWh, which does not differ significantly from 1 MWh.

The generation impact analysis also serves as a test for whether our estimates of the CO2 impacts are biased towards zero. Recall, the observed CO2 emissions come from the fossil units in the EPA CEMS dataset. To ensure that the CEMS dataset captures the output, and emissions, from the full set of generating units that respond to shifts in imports into California, we also estimate whether the response of natural gas and coal generators in the CEMS dataset is in line with the output changes observed in the EIA 930 dataset. Using the estimated net generation from natural gas units and coal units in the CEMS dataset, we find that increasing imports into California by 1 MWh causes net non-CA WECC natural gas and coal generation to increase by 0.553 MWh and 0.208 MWh, respectively. These point estimates are similar to the 0.569 MWh increase in natural gas generation and 0.223 MWh increase in coal generation uncovered using the EIA 930 data – again suggesting that the contemporaneous emissions impact displayed in Table 3 above are accurate.

Table 3: Change in Daily Non-CA Generation (MWh) by Fuel Source

	EIA 930 Dataset					EPA CEMS Dataset	
Independent Variable	Nat. Gas (1)	Coal (2)	Nuclear (3)	Hydro (4)	All (5)	Nat. Gas (6)	Coal (7)
$Imports_d$	0.569**	0.223**	-0.02	0.277**	1.038**	0.553**	0.208**
	(0.054)	(0.060)	(0.034)	(0.064)	(0.055)	(0.058)	(0.042)
N	1,394	1,394	1,394	1,394	1,394	1,394	1,394
R^2	0.944	0.940	0.953	0.937	0.985	0.938	0.968
Year-by-Month FE	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Non-CA Demand	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Non-CA Renewables	Yes	Yes	Yes	Yes	Yes	Yes	Yes

Note: Each column presents estimates of the coefficient on Gross CA Imports from the general model specified by Eq. 1 using daily observations from July 1, 2018 through Dec. 31, 2022. For each model, the dependent variable is the daily aggregate generation (MWh) from non-CA WECC generators separated by fuel source. columns (1) through (4) report the average change in natrual gas, coal, nuclear, and hydroelectric generation reported in the EIA 930 dataset. Column (5) reports the average change in generation across all fuel source reported in the EIA 930 dataset. Columns (6) and (7) report the average change in net generation estimated from the EPA CEMS dataset. Each of the models are estimated using two-stage least squares, with the first stage specified by Eq. 2. For each coefficient, standards errors robust to clustering at the week-of-sample level are reported in parentheses. * = signficant at the 5% level; ** = signifcant at the 1% level.

The estimate from column (1) of Table 2 reveals that, during the period from July 2018 through December 2022, each additional MWh of electricity imported into California increased out-of-state emissions on the same day by an average of 0.468 metric tons of CO2. If all of the increased out-of-state generation caused by California's imports came from resources that didn't face a binding constraint on the aggregate amount of electricity they could supply over the long-run (e.g., fossil fuel units), then this contemporaneous increase of 0.468 metric tons of CO2 per MWh would capture the full impact of California imports on emissions. However, the results in Table 3 reveal that, on average, 0.277 MWh of each imported MWh is supplied by out-of-state hydroelectric units. Because the aggregate hydroelectric generation that can be supplied over a given period of time (e.g., a year) is dictated by the water levels in the surface waterways throughout the WECC region, shifts in California's demand for electricity will not affect the overall annual generation available from WECC hydroelectric units. Consequently, if

California's imports on a given day increase out-of-state hydroelectric generation on the same day, then this implies that there will be an equal reduction in hydroelectric generation that can be supplied at a different point in time. If this non-contemporaneous reduction in hydroelectric potential results in a corresponding increase in out-of-state fossil generation, then there will be a non-contemporaneous increase in out-of-state emissions. The objective of the following subsection is to introduce an approach that can be used to quantify how much out-of-state CO2 increases in response to each MWh of hydroelectric generation that California imports.

Non-contemporaneous Impacts of Imports

To quantify the non-contemporaneous impact of imports on emissions, there are three key assumptions that must be made. First, we must constrain the period over which the non-contemporaneous impacts can occur. That is, if an additional MWh of out-of-state hydroelectric output is imported into California today, when can the corresponding 1 MWh reduction in hydroelectric output feasibly occur? For the following analysis, we assume that the corresponding reduction in aggregate hydroelectric output can occur at any point throughout the same calendar year (in subsequent analyses, estimates will also be made imposing a range of alternative assumptions – e.g., the non-contemporaneous impacts are constrained to occur within the same calendar month, or only in subsequent months).

Second, once we have constrained the non-contemporaneous hydroelectric changes to a given period of time (e.g., a calendar year), we must impose an assumption surrounding how the reduction in each MWh of potential hydroelectric generation will be distributed throughout the full calendar year (e.g., during which hours of the day will the non-contemporaneous reductions in hydroelectric output be more pronounced?). In the following analysis, we assume that there will be a uniform percentage reduction in total non-CA WECC hydroelectric output during each hour of the year. That is, let $Hydro_{h,d}$ represent the total non-CA WECC hydroelectric output observed during hour h of day d and let $\overline{Hydro}_y$ represent the total non-CA WECC hydroelectric generation during the corresponding year. If imports into California cause a 1 MWh contemporaneous increase in non-CA WECC hydroelectric generation, we assume that during hour h of day d of the same calendar year, non-CA WECC hydroelectric output will be reduced by $Hydro_{h,d}/\overline{Hydro}_y$ MWhs.

Third and finally, we must impose an assumption on which generators will increase their output (and therefore emissions) in response to the non-contemporaneous reductions in hydroelectric output. Here, we assume that fossil fuel units will exclusively be the marginal sources that replace the missing hydroelectric generation. Intuitively, intermittent renewable sources (e.g., wind and solar) will not experience an increase in output in response to the reduction in hydroelectric potential given that their output is dictated again by nature (e.g., wind speeds and solar radiation). Moreover, as Table 3 highlights, output from non-CA nuclear units is not responsive to shifts in residual demand – and thus, we assume they will not serve as substitutes for the hydroelectric output.

Combined, the above assumptions imply that, for each MWh of hydroelectric output used to meet California's imports, non-CA WECC fossil generation during each hour of the corresponding year will increase by $Hydro_{h,d}/\overline{Hydro}_y$ MWhs. To quantify how this increase in fossil output will affect the aggregate annual emissions from non-CA WECC fossil units, we estimate the average hourly Marginal

Emission Rate (MER), which is allowed to flexibly vary by hour-by-month, for the non-CA WECC fossil generators.

To initially estimate the hour-by-month MERs to quantify the non-contemporaneous impact of imports on emissions over the period from July 2018 through December 2022, we estimate the following model using hourly observations spanning July 2018 through December 2022:

$$Emissions_{h,d,m,y} = \mu_{h,m} \cdot NetFossil_{h,d,m,y} + \alpha_{h,m,y} + \varepsilon_{h,d,m,y} \tag{3}$$

where $Emissions_{h,d,m,y}$ represents the total CO2 (metric tons) emitted by non-CA WECC fossil units (in the EPA CEMS dataset) during hour h of day d, month m, and year y, and $NetFossil_{h,d,m,y}$ represent the net generation from the same fossil units during the corresponding hour. The key coefficients of interest, $\mu_{h,m}$, represent the average increase in non-CA WECC CO2 emissions in response to a 1 MWh increase in total non-CA WECC fossil net generation during hour h of month m. To control for seasonal or longer run trends in the hourly average emissions and fossil generation, the model specified by Eq. 3 includes hourly fixed effects ($\alpha_{h,m,y}$) that are allowed to vary flexibly by month-of-year. The remaining unexplained variation in the hourly observed emissions is captured by the error term, $\varepsilon_{h,d,m,y}$.To highlight the patterns displayed by the marginal emission rate estimates, the top panel of Figure 3 below displays the estimates of the marginal emission rates, averaged across months, for each hour of the day. On average, an additional MWh of fossil generation from non-CA WECC units during the first few hours of the day (the overnight hours) causes an additional 0.68 metric tons of CO2 to be emitted. This marginal emission rate falls slightly (to roughly 0.65 metric tons/MWh during the 7am to 8am period), rebounds midday, and falls again as system loads peak in the afternoon hours. To understand what drives the observed within-day variation in the marginal emission rates, we re-estimate Eq. 3 using the hourly net generation from natural gas and coal units (in the CEMS dataset) as the dependent variables. The resulting point estimates of $\mu_{h,m}$ now represent the average share of the marginal fossil output supplied by natural gas or coal units. The bottom panel of Figure 3 displays the averages of the marginal fuel shares by hour-of-day (averaging across the months again). The figure demonstrates that, during the hours when the marginal emission rates are at their lowest, the share of marginal fossil generation being met by natural gas units is the highest.

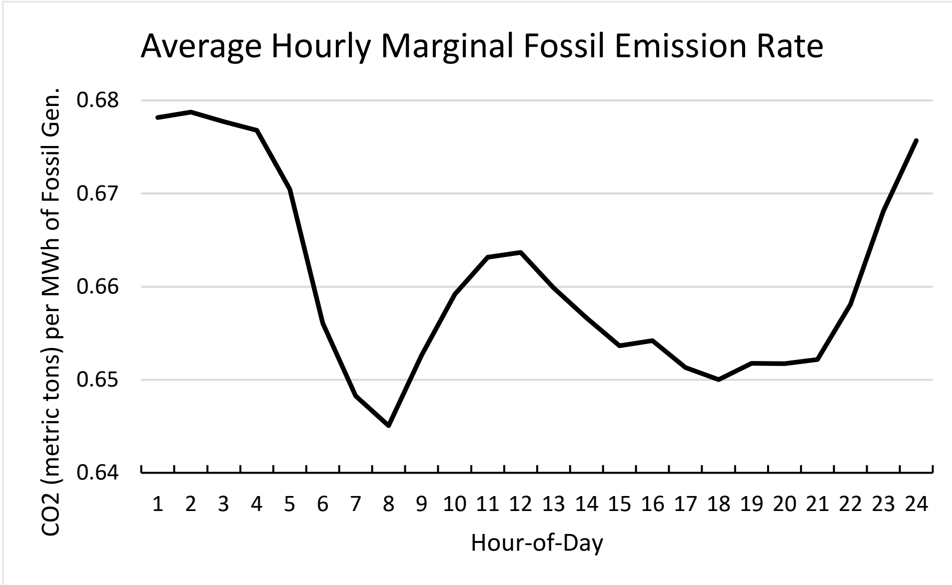

Figure 3: Average Hourly Marginal Emission Rates from Fossil Fuel

With the estimates of the hour-by-month MERs from Eq. 3, we can estimate the non-contemporaneous increase in non-CA WECC emissions for each 1 MWh of non-CA WECC hydroelectric output imported by California using the following expression:

$$\text{Non-Contemporaneous Impact } = \hat{\beta}^{non} = \sum_{\forall h,m} \hat{\mu}_{h,m} \cdot \frac{\overline{Hydro}_{h,m}}{\overline{Hydro}} \tag{4}$$

where $\hat{\mu}_{h,m}$ is the estimate of the MER during hour h of month m and $\overline{Hydro}_{h,m}/\overline{Hydro}$ is the share of total non-CA WECC hydroelectric output (during the July 2018 through December 2022 period) that is observed during hour h of month m. Summing the product of the two terms across the 24-by-12 hour-by-month pairs yields an estimate of the non-contemporaneous increase in non-CA WECC CO2 emission for each MWh of hydroelectric output of $\hat{\beta}^{non} = 0.668$ metric tons of CO2. That is, for each MWh of non-CA WECC hydroelectric output supplied to California, we estimate that there will be a non-contemporaneous increase in non-CA WECC carbon emissions during other hours which sums to 0.668 metric tons of CO2.

Total Impact of Imports on Out-of-State Emissions

Ultimately, the total impact of California's imports on non-CA WECC emissions is comprised of the contemporaneous and non-contemporaneous impacts. That is, for each MWh imported into California during the period spanning July 2018 through December 2022, we calculate that non-CA WECC-wide emissions of CO2 increase with the following expression:

$$\text{Total Impact} = \hat{\beta}^{cont} + (0.277) \cdot \hat{\beta}^{non} = 0.468 + (0.277) \cdot 0.668 = \mathbf{0.653\ metric\ tons\ CO_2/MWh}$$

where the $\hat{\beta}^{cont}$ is the estimate of the contemporaneous impact of importing a MWh on emissions (column (1) of Table 2), 0.277 is the estimate of the contemporaneous share of imported energy coming from non-CA WECC hydroelectric units (column (4) of Table 3), and $\hat{\beta}^{non}$ is the estimate of the non-contemporaneous impact of consuming a MWh of hydroelectric output on non-CA WECC emissions (from Eq. 4).

To quantify the average annual emissions caused by California's electricity imports, we can multiply the average increase in non-CA WECC-wide emissions of 0.653 metric tons of CO2 per MWh imported (from the 'Total Impact' equation immediately above) by the average annual gross imports. Over the five-year period from 2018 through 2022, the average annual contracted imports into California were 93,181 GWh/year. Multiplying this by the estimated 0.653 metric tons of CO2 per MWh imported yields an estimate of 60.84 mmTons of CO2 per year caused by California's imports.

While the preceding analysis provides a direct estimate of the annual out-of-state emissions caused by California's imports over the period from 2018 through 2022, the same estimation procedure cannot be replicated prior to 2018. Recall from the results displayed in Table 1, if we are unable to control for renewable production outside of California, the approach would appear to lead to biased estimates of the contemporaneous emissions impacts of imports. Given that we are constrained to only observing non-CA WECC renewable production at the hourly level from July 2018 to present, we cannot replicate the same estimation procedure in the earlier years of the Cap-and-Trade Program.

In the following section, we introduce an alternative estimation procedure that builds on the approach employed above. In particular, we separately estimate the contemporaneous and non-contemporaneous impacts of imports on emissions. Importantly, the new 'data-constrained' estimation procedure allows us to overcome the inability to observe generation by non-fossil fuel sources. To validate the data-constrained estimation procedure, we compare the resulting 'data-constrained' estimates of the annual emissions caused by California's imports over the period from 2018 through 2022 to the preceding causal estimates (i.e., 60.84 mmTons of CO2 per year caused by California's imports). After validating the data-constrained procedure over these more recent years of the Cap-and-Trade Program, we then quantify the annual impact of imports on out-of-state emissions going back to 2011. This series of annual emissions caused by California's imports will finally be compared to the reported annual emissions attributed to imports (Figure).

5. Data-Constrained Estimation Procedure

To quantify how California's electricity imports affect CO2 emissions from out-of-state electricity generators, we will build on the estimation approach employed in the previous section. In particular, we will again separately quantify the contemporaneous impact (i.e., how much does an increase in imports into California increase out-of-state CO2 emissions during the same hour?) and the non-contemporaneous impact (i.e., if out-of-state hydroelectric output is used to meet a portion of California's imports during a given hour, how much do out-of-state CO2 emissions increase during other periods of the year?). In this section, however, we apply a different methodology to compensate for the reduced data available prior to 2018.

Data-Constrained Estimates of Contemporaneous Impacts

In Section 4, we employed a reduced-form empirical strategy that did not require us to impose any assumptions with regards to how an increase in imports into California will affect the contemporaneous level of generation and emissions from electricity generators throughout the WECC. However, while we did not need to impose strong assumptions regarding which fuel sources respond to contemporaneous shifts in California's demand for imports, we nonetheless needed to be able to observe the daily (or hourly) level of generation by various fuel sources in order to control for potential endogeneity concerns (e.g., correlation between the daily (or hourly) level of out-of-state renewable output and imports into California). Given that the generation by each individual fuel-source is not observed throughout the period of interest – in particular, prior to July 2018 – we must now impose two assumptions surrounding how generation from out-of-state suppliers respond to increases in imports into California. Importantly, both of these assumptions are guided by the reduced form results presented in Section 4.

First, to quantify the contemporaneous impact of imports on emissions, we assume that, in the short-run, an increase in the hourly level of imports into California will be met exclusively by a corresponding increase in the aggregate output from non-CA WECC fossil fuel units and non-CA WECC hydroelectric units. Effectively, we assume that a change in the hourly imports into California does not cause a change in out-of-state nuclear or renewable production. Assuming that non-CA WECC nuclear output is unaffected by shifts in California's demand for imports is straightforward given that the nuclear units behave as baseload capacity, supplying at full capacity whenever they are available. It is also consistent with the finding displayed in Table 3 that demonstrates the daily level on out-of-state nuclear generation is unaffected by the daily level of imports into California. The assumption that shifts in California's imports cannot cause short-run changes in out-of-state (non-hydroelectric) renewable output is consistent with the fact that, in the short-run, shifts in renewable production are dictated by fluctuations in weather conditions (e.g., wind speeds, solar irradiance) rather than changes in demand. This does impose the assumption that, over the period examined, shifts in California's imports do not impact the level of renewable curtailment occurring outside of California. While there is evidence that short-run shifts in California's electricity demand have small impacts on in-state solar curtailment (Novan and Wang, 2024), there is no evidence of similar impacts on out-of-state curtailment.

Second, to quantify the contemporaneous impacts of California's imports on out-of-state electricity generators, we assume that an increase in imports into California will have the same impact on non-CA generators as an increase in demand outside of California. That is, a marginal increase in the demand for non-CA electricity production will have the same impact on non-CA WECC generators regardless of where the increase in demand stems from (this is an assumption that can be relaxed in future analyses by allowing the response of generators to demand shifts differ based on where the demand shifts occur within the WECC region). While this assumption abstracts from the existence of congestion and transmission constraints in the WECC grid outside of California, this simplifying assumption is nonetheless consistent with the estimates covered in Section 3. In particular, the estimates of the model specified by Eq. 1 reveal that, on average, the response of non-CA emissions to a marginal increase in gross imports into California does not differ significantly from the response to a marginal increase in non-CA WECC load.

Combined, the above two assumptions make it possible to quantify how an increase in imports into California during a given hour will affect the aggregate out-of-state CO2 emissions during the corresponding hour (i.e., the contemporaneous impact of imports on emissions).

Under the first assumption introduced above, increasing California's imports by 1 MWh during hour h on day d of month m and year y must increase the aggregate net generation from non-CA WECC hydroelectric units ($Hydro_{h,d,m,y}$) and fossil units ($Fossil_{h,d,m,y}$) by 1 MWh. We define $\tilde{Q}_{h,d,m,y}$ to be the sum of the net generation from out-of-state hydroelectric and fossil units ($\tilde{Q}_{h,d,m,y} = Hydro_{h,d,m,y} + Fossil_{h,d,m,y}$). The value of $Fossil_{h,d,m,y}$ is calculated by multiplying the observed gross hourly fossil generation from the CEMS dataset by the corresponding unit's net-to-gross ratio for the corresponding quarter. In addition, $Hydro_{h,d,m,y}$ is predicted by imputing the share of observed monthly hydroelectric output that occurs during each hour of the corresponding month (see the Appendix for details of the imputation process). The contemporaneous increase in out-of-state emissions ($CO2_{h,d,m,y}$) caused by this 1 MWh increase in $\tilde{Q}_{h,d,m,y}$ is ultimately dictated by (A) how much of the marginal increase in output comes from fossil units versus hydroelectric units, and (B) the emission rate of the marginal fossil units. Importantly, the second assumption above implies that both of these margins – i.e., the share of the marginal output that comes from fossil units, and the composition (e.g., coal vs. natural gas) of the marginal fossil units – are identical regardless of whether the increase in $\tilde{Q}_{h,d,m,y}$ is caused by a 1 MWh increase in non-CA load or a 1 MWh increase in imports into California. Consequently, we can estimate the average contemporaneous increase in out-of-state CO2 emissions in response to a 1 MWh increase in California's imports using the equation specified below:

$$CO2_{h,d,m,y} = \beta^{c}_{h,m,y} \cdot \tilde{Q}_{h,d,m,y} + \alpha^{c}_{h,m,y} + \epsilon^{c}_{h,d,m,y} \tag{5}$$

where $\beta^{c}_{h,m,y}$ represents the average contemporaneous change in out-of-state emissions caused by a 1 MWh increase in out-of-state fossil and hydroelectric generation during hour h of month m in year y. The model specified by Eq. 5 above allows the contemporaneous emission impact to differ by hour-by-month-by-year to account for the fact that the composition of the marginal generators can vary not only across hours of the day and across seasons as WECC-wide demand fluctuates, but also across years (e.g., as fuel prices change; as capacity additions and retirements occur).

Finally, using these estimates from Eq. 5, we can estimate the average annual contemporaneous increase in non-CA WECC emissions caused by importing a MWh into California during year y using the following expression:

$$\text{Avg. Contemporaneous Impact}_y = \sum_{\forall h,m} \hat{\beta}^{c}{}_{h,m,y} \cdot \frac{\overline{Imports}_{h,m,y}}{\overline{Imports}_y} \tag{6}$$

where $\overline{Imports}_{h,m,y}/\overline{Imports}_y$ is the share of total California imports during year y ($\overline{Imports}_y$) that occurs during hour h of month m of the corresponding year. That is, the average annual contemporaneous impact of imports on emissions is simply a weighted average of the hour-by-month contemporaneous impacts for the corresponding year, with the import-share weights placing greater weight on the hours and months when the level of total imports is higher. Table 4 below displays the estimates of Eq. 6 for each year from 2011 through 2022. Recall, from Section 4, our benchmark causal estimates revealed that, from July 2018 through December 2022, an additional MWh of imports into

California caused a contemporaneous increase in out-of-state CO2 of 0.468 metric tons on average (column (1) of Table 2). For comparison, the simple average of the 2018 through 2022 estimates is 0.491 metric tons of CO2/MWh, in line with the earlier direct causal estimates.

Table 4: Avg. Annual Contemporaneous Impact on Emissions

Year	Contemporaneous Impact on Emissions (metric tons of CO2/MWh)
2011	0.500
2012	0.501
2013	0.512
2014	0.543
2015	0.548
2016	0.559
2017	0.520
2018	0.508
2019	0.519
2020	0.485
2021	0.483
2022	0.459

Data-Constrained Estimates of Non-Contemporaneous Impacts

Again, if a portion of the increase in imports into California is supplied by a contemporaneous increase in out-of-state hydroelectric output, then there can be a resulting non-contemporaneous impact on out-of-state emissions. To quantify how large this non-contemporaneous impact is per MWh imported during each individual year, we first estimate how much out-of-state hydroelectric output increases in response to a 1 MWh increase in imports into California. To do so, we continue to assume that (A) an increase in imports into California will exclusively cause output to increase from out-of-state fossil and hydroelectric sources, and (B) a 1 MWh increase in out-of-state demand or a 1 MWh increase in imports into California will cause the same response among out-of-state fossil and hydroelectric sources. Under these assumptions, we can estimate the average contemporaneous increase in out-of-state hydroelectric generation caused by a 1 MWh increase in California's imports using the equation specified below:

$$Hydro_{h,d,m,y} = \beta^h_{h,m,y} \cdot \tilde{Q}_{h,d,m,y} + \alpha^h_{h,m,y} + \epsilon^h_{h,d,m,y} \quad (7)$$

In the equation specified above, $\beta^h_{h,m,y}$ represents the average contemporaneous increase in out-of-state hydroelectric output caused by increasing imports into California by 1 MWh during hour h of month m during year y. To quantify the annual average increase in out-of-state hydroelectric output caused by importing a MWh into California during each individual year, we weight the estimate of $\beta^h_{h,m,y}$ by the observed share of annual imports that occur during that particular hour-by-month:

$$\text{Avg. Contemporaneous Impact on Hydro}_y = \sum_{\forall h,m} \hat{\beta}^h{}_{h,m,y} \cdot \frac{\overline{Imports}_{h,m,y}}{\overline{Imports}_y} \quad (8)$$

Table 5 displays the estimates from Eq. 8 of the average contemporaneous increase in out-of-state hydroelectric output for each year from 2011 through 2022. Recall from the direct causal estimates displayed in Table 3, from July 2018 through 2022, increasing imports into California by 1 MWh caused an average contemporaneous increase in out-of-state hydroelectric output of 0.277 MWh. Again, the estimates from our data-constrained procedure are very much in line with these benchmark causal estimates. The average of the 2018 through 2022 annual contemporaneous impacts displayed in Table 5 is a 0.270 MWh increase in out-of-state hydroelectric output in response to a 1 MWh increase in imports into California.

Table 5: Avg. Annual Contemporaneous Impact on Hydroelectric Generation

Year	Contemporaneous Impact on Hydro (MWh/MWh)
2011	0.256
2012	0.263
2013	0.199
2014	0.197
2015	0.222
2016	0.205
2017	0.228
2018	0.247
2019	0.254
2020	0.269
2021	0.261
2022	0.318

Finally, to quantify how much out-of-state CO2 emissions will increase during all other hours of the year in response to each 1 MWh of hydroelectric output supplied to meet an increase in California imports, we again follow the same approach employed in Section 4. We estimate the average marginal emission rate from out-of-state fossil units for each hour of each month for each year (Eq. 3). We then weight these hour-by-month-by-year estimates of the average marginal emission rate for non-CA WECC fossil generation by the share of the total annual hydroelectric output that occurs during the corresponding hour-by-month for each individual year (Eq. 4). The result is an estimate of how much the annual CO2 emissions increase per MWh of hydroelectric output used to meet California's contemporaneous level of imports. Recall, this approach again assumes that for each MWh of out-of-state hydroelectric output used to meet California's imports, there is an equal percentage reduction in hourly hydroelectric output across all other hours of the corresponding year.

To summarize the full set of estimates from the data-constrained procedure described above, Figure 4 displays the estimates of the average contemporaneous and non-contemporaneous change in out-of-state CO2 emissions caused by importing a MWh into California for each year from 2011 through 2021. In addition, the aggregate change in out-of-state emissions caused by importing a MWh (i.e., the sum of the contemporaneous and non-contemporaneous impacts) is also displayed for each year. It is important to emphasize, these estimates all assume that all of the electricity imported into California is coming from the marginal generation sources out of state. Recall from Section 4, our direct estimation procedure found that, from July 2018 through December 2022, on average, increasing imports into California by 1 MWh caused out-of-state emissions to increase by 0.653 metric tons. For comparison, the simple average of the 2018 through 2021 estimates of the total impacts displayed in Figure 4 is 0.669 metric tons of CO2 per MWh imported.

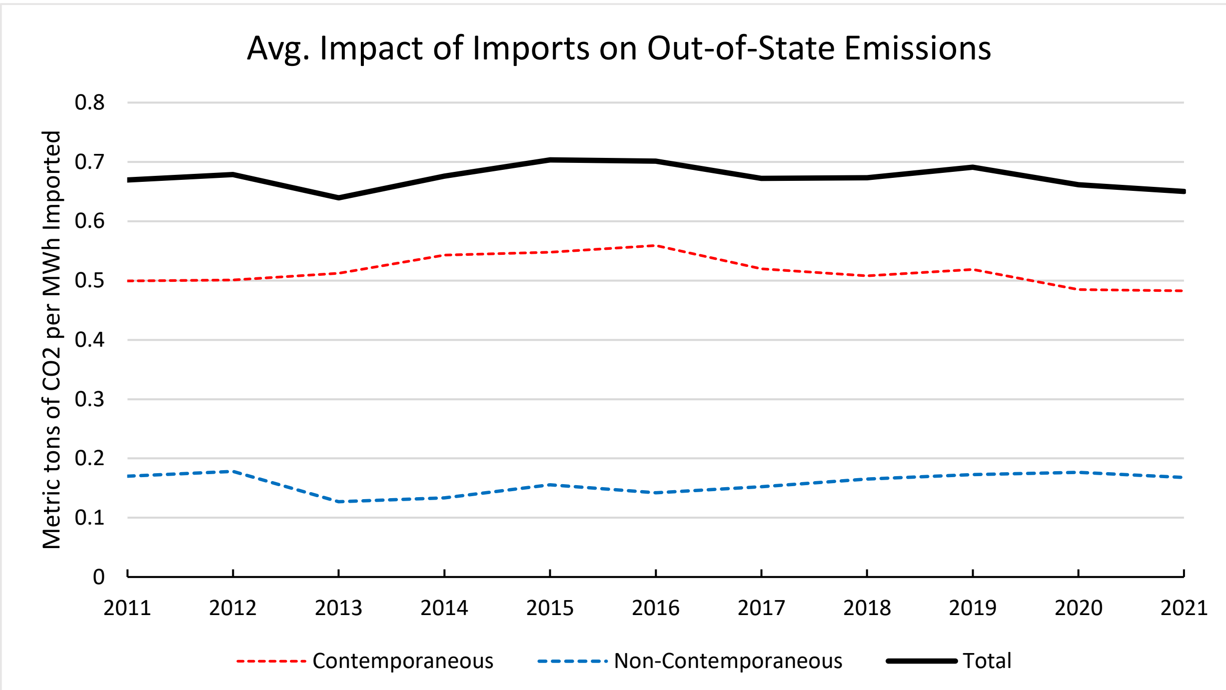

Figure 4: Average Change in Out-of-State Emissions per MWh Imported

To quantify the annual emissions caused by California's electricity imports, we multiply the average emissions caused by importing a MWh of electricity (the "Total" value displayed in Figure 4 above) by the corresponding annual imports reported (displayed in the top panel of Figure 1). Importantly, this assumes that all of the imported energy coming into California is supplied by the marginal generators outside of California. As the subsequent long-run analysis highlights, there has been a steady increase in reported imports into California from new out-of-state generation capacity – and in particular, new intermittent renewable sources (e.g., wind and solar). If this growth in out-of-state renewable capacity was induced by California's Cap-and-Trade Program, then our estimation approach would overstate the emissions that should be attributed to California's imports. To account for the potential endogenous growth in out-of-state renewables caused by the Cap-and-Trade Program, we also make an alternative estimate of the annual emissions caused by imports. Rather than assuming that all of the imports into California come from the marginal generators outside of the state, we assume that only the reported imports that are not coming from new (i.e., post-2011) wind and solar capacity come from the marginal generation outside of California.

To summarize how the resulting estimates of the annual emissions caused by imports have changed since the introduction of the Cap-and-Trade Program, we calculate the difference between the estimated annual emissions during each year relative to the estimated annual emissions attributed to imports in 2011. In addition, we calculate the change in the reported annual emissions relative to the reported imported emissions during 2011. **Error! Reference source not found.** displays the resulting estimates of the trends in annual emissions attributed to California's imports. Under the assumption that the new out-of-state renewable capacity in the reported imports was caused by the Cap-and-Trade Program (the red line in the figure below), we estimate that the annual emissions attributed to California's imports in 2021 were 14 mmTons lower than the 2011 emissions caused by California's imports. For comparison, the reported annual emissions attributed to California's imports were 29 mmTons lower in 2021 relative to 2011. That is, our estimates displayed by the red line below find that 48% of the reported emission reductions in 2021 relative to 2011 were achieved. In contrast, if we assume that none of the renewable capacity growth outside of the state was caused by the Cap-and-Trade Program (the solid black line below), we estimate that the emissions attributed to California's imports fell by 6.6 mmTons in 2021 relative to 2011 (22% of the reported decline in emissions). These results highlight the importance of the assumptions surrounding how longer-run changes in generation capacity respond to California's Cap-and-Trade Program. In the subsequent section, we examine the long-run trends in out-of-state generation capacity and decompose how these changes contribute to the reported decline in emissions attributed to California's imports.

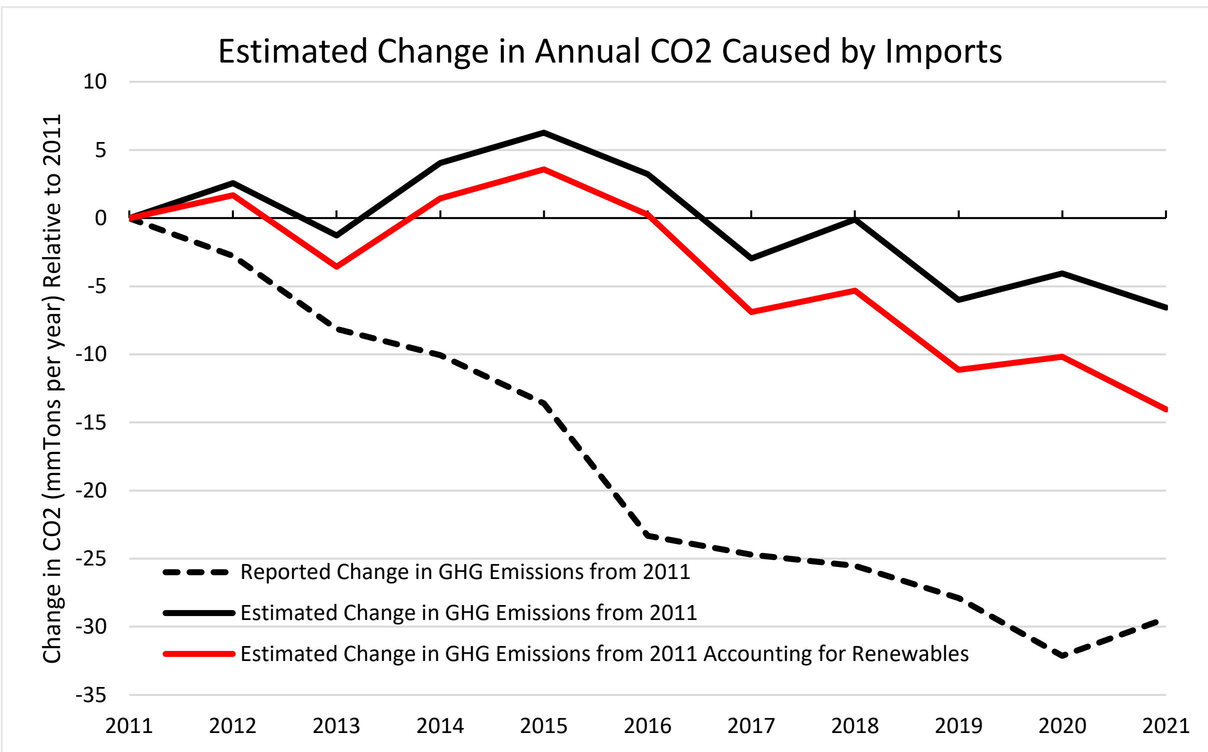

Figure 5:Change in Emissions Relative to 2011

6. Long-run Attributional Trends in Capacity Changes and Emissions

The CARB datasets provide a rich picture of the set of resources identified as sources of imports, while the EIA and EPA datasets provide similar information about overall production and emissions from all sources outside of California. Importantly, by combining these datasets, we can also measure the portion of emissions and energy produced at importing plants that was *not* designated as an import source. In other words, for importing sources we also can measure the production deemed delivered to customers outside of California.

Emissions trends over the last decade

We begin with a summary of the generation mix just before the start of the Cap-and-Trade Program in 2011 compared to the mix 10 years later in 2021. The far left-hand bar in Figure 6 illustrates the market share of energy imports reported to CARB by major fuel source in 2011. The second bar from the left illustrates the same breakdown in 2011, but for the western grid (WECC) excluding California. The third bar from the left illustrates the mix of imports reported to CARB in 2021, and the right most graph illustrates the energy production in the WECC (less California) in 2021. The energy reflected in the left-hand bars is essentially the portion of the energy described on the right-hand bars that was chosen as an import source into California. One major distinction between the two groups is the large share of "unspecified" in the CARB emissions inventory import data. Unspecified sources are assumed to have emissions equivalent to an efficient natural gas plant. In the early years of the Program there was concern that this would create an incentive for less efficient natural gas and coal sources to become (or remain) unspecified (Bushnell, et. al. 2014, Cullenward and Weiskopf, 2013). However, the combined share of coal, gas and unspecified energy fell from roughly 73% of all imported energy in 2011 to under 42% in 2021.

Conversely the share of very low, or zero, carbon energy from hydroelectric, nuclear, and renewable sources grew from about 25% of imported energy in 2011 to over 50% in 2021. While some of this came from growth in wind and solar energy, there was a large jump in imports from existing hydroelectric and nuclear energy as well. Hydroelectric and nuclear combined rose from a 21% share of imports in 2011 to over 33% in 2021.

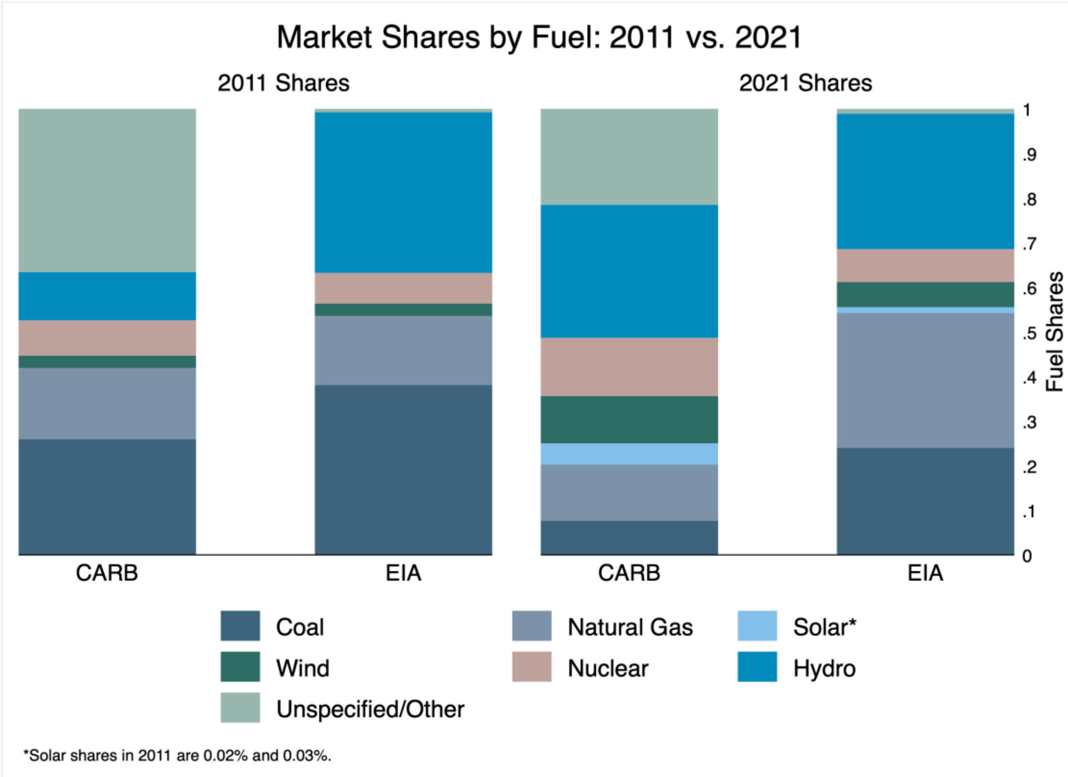

Figure 6: Non-California WECC-wide generation shares by fuel source

Emissions from electricity deemed imported into California fell substantially over this ten-year period, in no small part due to this substantial increase in the share of zero-carbon energy in the import mix. Recall that Figure 2 (in section 3) graphs the annual emissions by fuel source from electricity imported into California.

Capacity Retirements and Additions in the WECC

We can identify the sources of imports that experience capacity changes (either expansion or retirement) by combining the CARB import datasets with EIA form 860 data. To construct the list of retirements and entrants, we utilize, primarily, the Energy Information Administration's (EIA) Form 860. For most units (3,096/3,127, or 99%), no discrepancies arose regarding entry and retirement years. Because there were few discrepancies, each discrepancy was individually investigated. In most cases, this amounted to assigning the mode of the reported entry or retirement dates. In cases where this rule could not be applied, the EIA's Form 923, which provides data on monthly net generation, was used to determine the most likely entry or retirement date.

Table 6: Non-California WECC Capacity Changes

Capacity (GWh) Changes in non-CA WECC, 2011 to 2021

Source	2011 Capacity	2021 Capacity	Cum. Change	% Change
Coal	36.98	27.28	-9.71	-26.25
Natural Gas	43.98	47.04	3.06	6.95
Solar	0.51	10.31	9.80	1925.54
Hydro	40.42	40.69	0.27	0.66
Wind	10.17	23.62	13.45	132.31

Table 6 reports changes in capacity for all sources in the WECC, broken down by fuel source. Coal was the only source experiencing a reduction in capacity over the last decade. Table 7 reports a similar breakdown, but restricted only to units identified in the MRR data as a reported source of imports into California in at least one of 11 years in our sample. Almost all of the coal plants experiencing retirements in the last decade were at one time a source of imports into California. As we discuss below, a substantial share of emissions reduction is associated with reduced imports from these retiring coal plants. Another source of reductions is increased capacity from solar and wind resources located outside of California.

As we discuss below, a third important factor influencing reductions in import emissions is the increase in imports from hydroelectric sources. While the capacity associated with these sources appears relatively modest in the table below, there has been a substantial increase in imports from "primarily hydropower" sources. These sources are system-level imports from which specific sources are not specified, but the systems from which they are sourced contain substantial hydroelectric capacity and production.

Table 7: Capacity (GWh) Changes in Reported CA Import Sources, 2011 to 2021

Source	2011 Capacity	2021 Capacity	Cum. Change	% Change
Coal	28.20	20.81	-7.39	-26.22
Natural Gas	32.62	34.32	1.70	5.21
Solar	0.10	2.38	2.28	2401.89
Hydroelectric (specified)	7.84	7.84	0.00	-0.04
Wind	4.82	9.97	5.15	106.91

Import Volumes from Retiring and Newly Built Capacity

By again combining data from EIA form 860 data, EIA form 923 data, and the CARB Emissions Inventory, we can calculate the amount of energy imported from units that experienced a change in capacity during the last decade. In many cases the output of a given power plant is greater (sometimes far greater) than the volumes reported as imported into California. Rather than attempt to designate a change in a capacity as associated with the "import" or "non-import" share in any given year, we instead compile total annual production volumes and total annual import volumes for plants that experienced a change in capacity at any point during the period 2011-2021.

Figure 7 illustrates these annual volumes for coal plants grouped into one of two categories: those that experienced a unit retirement between 2011 and 2021 and those that did not. The former group is illustrated by the right-hand panel of Figure 7. Overall, this figure implies little shuffling away from California by coal plants. If imports from coal plants were fully reshuffled, the total output of the plant would remain relatively constant, the share going to California (brown bars) would have declined, and the share not going to California (blue bars) would have increased.

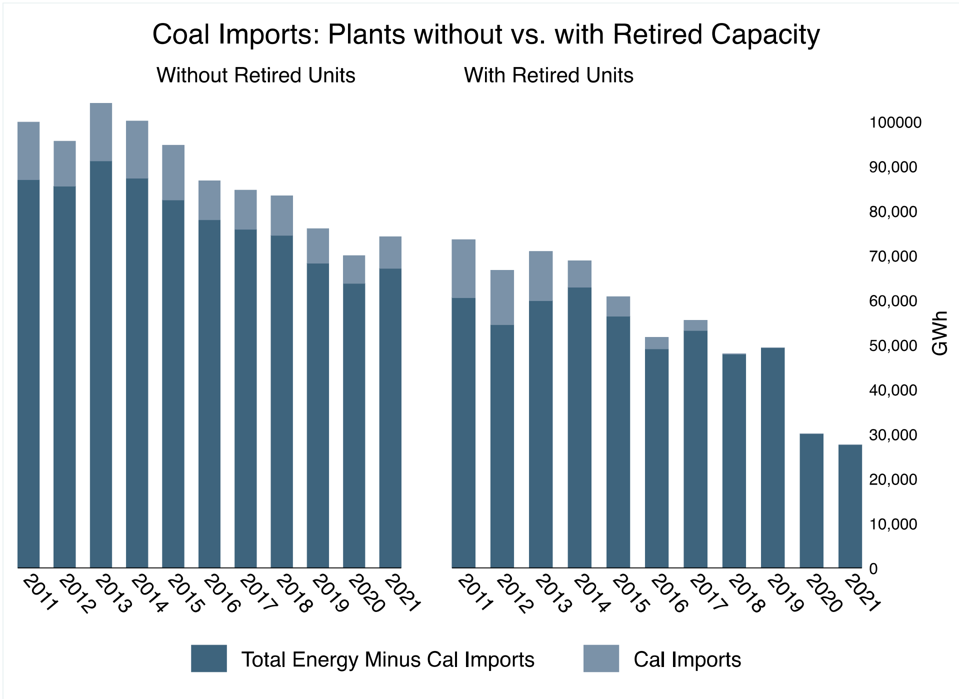

Figure 7: Changes in Coal Sources

Instead, the right-hand panel of Figure 7 illustrates that among the plants experiencing retirements, the decline in imports to California were matched and even exceeded by declines in overall production. While this pattern does not strictly hold on a year-to-year basis, the overall trend over the last decade is quite pronounced. Imports from plants in this category fell from around 12 GWh in 2011 to almost zero by 2018, but overall output from the same set of plants declined by around 15 GWh by 2019 and another 20 GWh from 2020 onward.[6]

We can similarly assess the shares of renewable energy associated with existing or newly constructed (or expanded) renewable generation. Figure 8 plots the MWh of imports reported from wind and solar sources. The left-hand panel reports energy from plants whose online date pre-dates 2011, and the right-hand panel reports energy from plants with no capacity prior to 2011. In this case, indications of reshuffling would come from an increase in imports from pre-existing facilities. Instead, almost all of the increase in imports from renewable sources are associated with new generation capacity, indicating almost no leakage occurred through this channel.

[6] We again note that these calculations are done at the plant level. In at least one case, that of the Four Corners plant, imports from individual units ended and output from those specific units continued, but *other* units at Four Corners were retired.

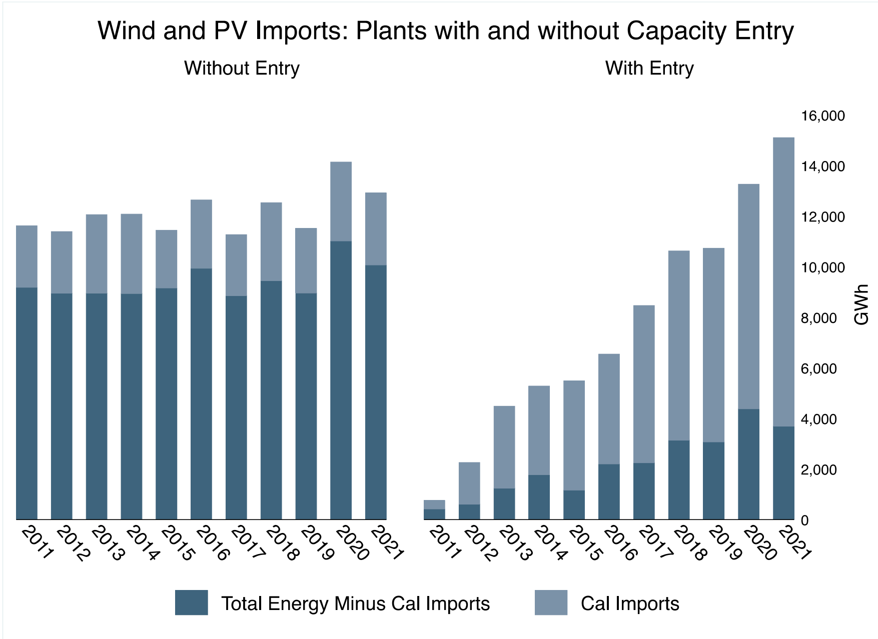

Figure 8: Changes in Renewable Sources

Figure 9 performs a similar calculation for nuclear and hydroelectric sources. Unlike wind and solar, there have been no new nuclear or large hydroelectric capacity additions for decades. However, the right-hand panel of Figure 9 illustrates that the amount of nuclear energy reported as imported into California (all from the Palo Verde nuclear station) has risen about 50%, from around 8,000 GWh per year to around 12,000 GWh per year, in the decade following 2011. These increased imports are not associated with a major change in the annual output from Palo Verde, which has remained steady at just over 30,000 GWh per year.

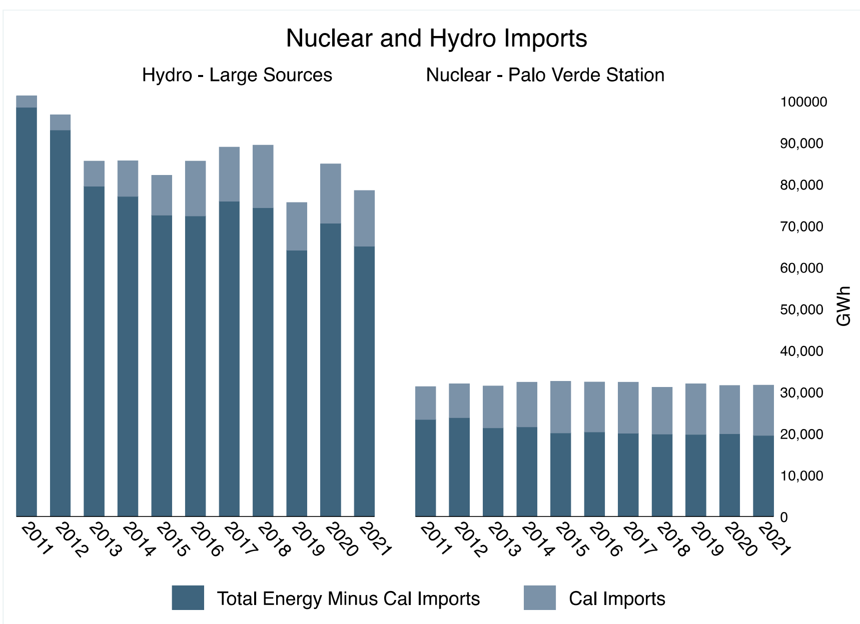

Figure 9: Changes in Imports from Large Hydroelectric and Nuclear Sources

A similar increase in the share of hydroelectric production from specified individual sources reported as imported into California has emerged over the last decade as well, despite the fact that overall output from these sources has declined since 2011. This is illustrated in the left-hand panel of Figure 11. In addition, imports from “largely hydroelectric” system resources have also grown substantially since 2015.

The analysis in this section highlights several trends in imported electricity that are suggestive of both true reductions in overall emissions and of leakage. On the one hand, declines in imports from coal plants has largely been matched or even exceeded by reductions in coal output overall. Further, increases in renewable sources can be traced to new construction, rather than substation to existing sources. These trends indicate that changes to these portions of California’s import portfolio reflect actual reductions in western electricity emissions and truly new zero-carbon capacity.

On the other hand, other trends in the import portfolio are indicative, at an aggregate level, of leakage. There has been a large growth in imports from incumbent zero-carbon sources that has replaced some imports from coal, natural gas, and unspecified sources. While most reductions in imports from coal sources can be traced to “real” reductions in output, the replacement of those imports with energy from existing low-carbon generation implies this clean energy, which was formerly serving customers outside of California, has now been replaced with higher-carbon sources. This points to a degree of leakage. In the following section we apply several assumptions to quantify the magnitudes of these differential trends.

7. Decomposition of Import Emissions Reductions

As described above, emissions associated with imported electricity have declined by roughly 25 mmTons per year in the decade following 2011. In this section we divide the sources of these import emissions reductions into several categories. This exercise helps to identify the types of reductions that might be associated with leakage, via a reallocation of generation sources across the western grid, and those that can more reliably be linked to new emissions reductions.

In defining each category, we focus our definitions on the changes to a given current source category and not on the relative change from one source type to a different source type. In other words, in most cases we apply a benchmark of the average reported emissions rate to define a generic source that is either being increased or decreased due to changes in one of the five categories. Thus, for example, we do not calculate the emissions changes resulting from coal GWh that were specifically replaced by Nuclear GWh. Such matching requires strong assumptions. The net effect of such a substitution is still captured in our calculation, however. Each GWh of reduced coal import is assumed to be replaced by an "average" GWh, and each GWh of nuclear (or hydroelectric) import is assumed in turn to be replacing an average GWh.

We assign emissions reductions into the following categories

1. **Reductions due to lower MWh volumes of imports.** Overall California is importing somewhat less electricity than it did a decade ago. Quantifying the emissions impact of a change in import volumes requires an assumption about the emissions rate of the "avoided" imports. We assume that the avoided imports would have had an emissions intensity equal to the average intensity of the prior year. More formally the reductions in year *t* associated with this category are assumed to be

$$\Delta GHG_1 = \Delta MWh^{imports} \cdot \frac{CO2_{e_{t-1}}}{MWh_{t-1}^{imports}}$$

2. **Reductions due to increased imports from newly constructed renewable sources.** The impact of increased renewable output is similar to that of reduced consumption in that both displace higher intensity electricity imports. As with reduced demand we assume that imports from new renewable sources displace emissions equivalent to the previous year's average intensity.

$$\Delta GHG_2 = -\Delta MWh^{renewables} \cdot \frac{CO2_{e_{t-1}}}{MWh_{t-1}^{imports}}$$

3. **Reductions due to reduced imports from coal plants that retire in the 2010s.** As described above, there is a group of coal plants outside of California who were once identified as sources of imports and whose collective total output has declined by over 40 TWh per year. Most of this output reduction is in turn due to the retirement of some or all generation units at those plants. The output from these units reported as sources of California imports declined from around 12 TWh in 2011 to effectively zero in 2021. In order to calculate the emissions *reduction* from the removal of these sources from California's import portfolio, we replace the energy previously identified as imports from plants in this category with energy assumed to have the average emissions rate of the current year. More formally

$$\Delta GHG_3 = \Delta MWh^{RetiringCoal} \cdot \left(\frac{CO2e_{t-1}^{RetiringCoal}}{MWh_{t-1}^{RetiringCoal}} - \frac{CO2e_{t-1}^{imports}}{MWh_{t-1}^{imports}} \right) +$$

$$+ MWh_t^{RetiringCoal} \cdot \left(\frac{CO2e_{t-1}^{RetiringCoal}}{MWh_{t-1}^{RetiringCoal}} - \frac{CO2e_{t}^{RetiringCoal}}{MWh_{t}^{RetiringCoal}} \right)$$

4. **Reductions due to increased imports from existing zero and near-zero carbon sources.** The share of imported energy coming from existing nuclear and hydroelectric resources has grown substantially since 2011. In addition, there has been a substantial growth in a category of semi-specified system-level sources called "primarily hydropower" that reports a very low, near zero, emissions intensity. We assume this new energy is displacing generation with an emissions rate equal to the current year's average emissions. We also adjust the reductions in this category for any changes in the (near-zero) emissions rates of sources in this category. More formally

$$\Delta GHG_4 = -\Delta MWh^{NearZero} \cdot \left(\frac{CO2e_{t-1}^{NearZero}}{MWh_{t-1}^{NearZero}} - \frac{CO2e_{t-1}^{imports}}{MWh_{t-1}^{imports}} \right) +$$

$$+ MWh_t^{NearZero} \cdot \left(\frac{CO2e_{t-1}^{NearZero}}{MWh_{t-1}^{NearZero}} - \frac{CO2e_{t}^{NearZero}}{MWh_{t}^{NearZero}} \right)$$

Note that if the emissions rate (CO2e/MWh) in year t is lower than in year t-1, the second term above is positive, reflecting the fact that this makes a positive contribution to the *reduction* in emissions. In practice, the collective emissions rate of near-zero sources is, as the name implies, small so this second term is not a substantial contributor.

5. **Reductions due to reduced energy imported and a lower emission intensity of imports from existing or new fossil sources.** This category captures the inverse of the impact of the previous category in that category 4 considers the benefit of replacing energy with average emissions with energy of near zero emissions, while category five considers the benefit of replacing relatively high emission fossil energy with lower average emission energy. The cumulative impact of replacing fossil emissions (described in category 5) with near-zero emissions (described in category 4) would therefore be the sum of these two categories. In addition, this category captures shifts in the composition of imports within the fossil (coal and natural gas)

sources by adjusting for the annual changes in the average emission rate from reported sources in this category. More formally

$$\Delta GHG_5 = -\Delta MWh^{Fossil} \cdot \left(\frac{CO2e_{t-1}^{Fossil}}{MWh_{t-1}^{Fossil}} - \frac{CO2e_{t-1}^{imports}}{MWh_{t-1}^{imports}} \right) + MWh_t^{Fossil} \cdot \left(\frac{CO2e_{t-1}^{Fossil}}{MWh_{t-1}^{Fossil}} - \frac{CO2e_t^{Fossil}}{MWh_t^{Fossil}} \right)$$

A sixth category, labeled as "RPS Adjustment" recognizes investments in out-of-State RPS-eligible electricity that is not directly delivered to California by adjusting the compliance obligation under the Cap-and-Trade Program. The RPS adjustment is voluntary, and it is only applicable when the importer purchases both electricity and renewable energy credits (REC) together and can demonstrate that the electricity was not delivered to California. The amount of the RPS Adjustment has fluctuated from year to year and accounted for about 2 mmTons of reductions in 2021 relative to 2011. The six categories described above capture more than 99% of the roughly 29 mmTons in cumulative reductions since 2011.

While we refer to these categories as "reductions," some categories did produce increases in emissions on a year-to-year basis during some years. These increases are negative reductions. Over the entire decade since 2010, all six categories produce cumulative reductions.

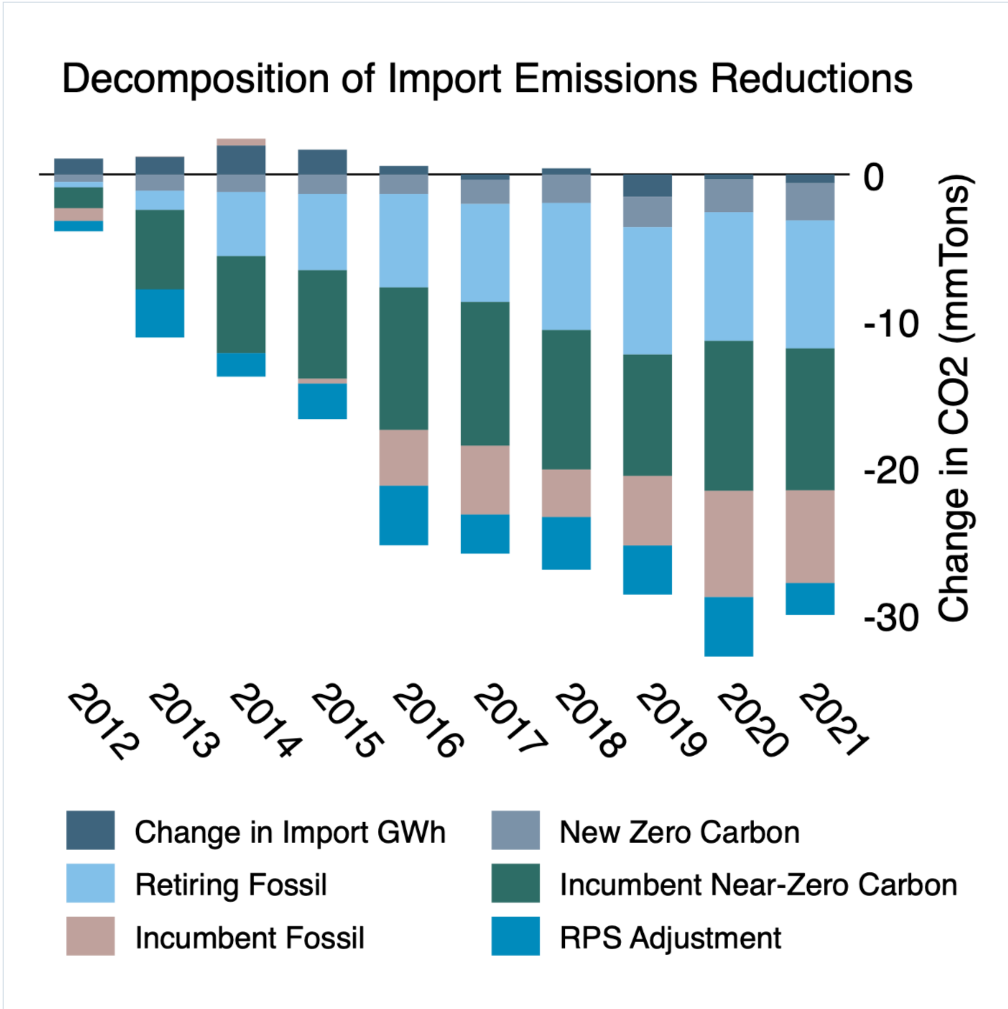

Figure 10: Sources of Emissions Reductions

Figure 10 illustrates an annual running cumulative total result of this decomposition. All increases or reductions are relative to the 2011 MRR baseline. Earlier in the last decade, there was an increase in imported energy volumes and, briefly, a small increase in the emissions intensity of fossil imports. Since 2017, all six categories have yielded reductions in total imported emissions.

To summarize, of the roughly 29 mmTons in emissions reductions from imports since 2011, about half can be traced to sources of firmly new reductions, such as retiring coal and new renewables, or to the RPS adjustment. The remaining half, around 14 mmTons, can be traced to substitution into either existing near-zero carbon sources or substitutions within the fossil category toward sources with lower emissions rates. The magnitudes described in this section are broadly consistent with those of Section 3, where again roughly half of the reductions could potentially be construed as leakage.

It is important to note that our analysis, and the summary above, address *aggregate* outcomes. There is an important distinction between aggregate outcomes and specific transactions that might constitute emissions leakage or violate the Cap-and-Trade Regulation's prohibition on reshuffling.

We are not aware of any evidence that any of these changes constituted activities that violate policies on reshuffling of sources. To the degree that these latter categories represent emissions leakage, they provide evidence that certain practices that are not considered reshuffling at an individual level may still result in emission leakage at an aggregate level. Some of these practices, such as importing from existing hydroelectric or nuclear sources, have long been discussed as potential avenues for leakage, but it has been difficult to develop policies to prevent them that do not conflict with Federal laws and do not significantly disrupt western power markets.

8. Interaction with Trends in California Retail Markets

The results described in Section 7 are aggregated by year for the entire state. They do not capture any heterogeneity in the import sources of individual LSE. As we discuss below, this is a limitation in the data made available through existing reporting requirements. While the MRR data do include imported electricity emissions at the firm level, the firms reporting imported electricity emissions are first deliverers. These entities execute transactions to import energy into California and in many cases resell this energy to LSEs. Therefore, the entities reporting imports in the MRR are in many cases not the same firms that ultimately take delivery of the imported energy.

While in many cases we cannot match specific import sources from the MRR to specific LSEs, the California Energy Commission Power Source Disclosure Program (PSDP) does collect data on the mix of sources utilized by each LSE in California. From these data we can examine trends about procurement across different classes of LSEs. Importantly, the PSDP data do *not* separately identify imported sources of energy, but rather break out LSE procurement by resource type.

The PSDP data are reported in the form of proportional shares, with each LSE reporting the percentage of energy procured to serve their retail customers. We convert these percentages into annual GWh quantities by multiplying the LSE shares by the LSE's total energy delivered to end use customers, taken from EIA form 861. This allows us to compare the energy delivered to various LSEs to changes in quantities from various sources into California.

Two caveats apply to our computation of computation by generation source for suppliers with multiple portfolios. For 2014, 2015, and 2020 through 2022, PCLs included total energy by source for each portfolio, so computation is straightforward. However, from 2016 to 2019, PCLs only reported the percentage make-up of each portfolio, not actual megawatt hour amounts for each. In 2015, multiple portfolio offerings were relatively rare, but by 2020, they were more widespread, meaning we need to account for changes to existing portfolio shares and the entry of new portfolios. To estimate portfolio shares for the missing years, we linearly interpolate shares from 2015 to 2020 for suppliers with multiple portfolios in 2015, or we backcast shares assuming a linear change for portfolios introduced during the missing years.[7]

[7] For example, if a retailer began offering plan B alongside A in 2016, and as of 2020 plan A's share of load was 80% and B's was 20%, we would assume plan B's share of load was initially 4% in 2016 and grew by that same amount in subsequent years.

Figure 11 summarizes the trend in the consumption of fossil fuel in California since 2014. We summarize purchases by LSEs in three broad categories: Utilities (both public and investor-owned), commercial "direct access" providers, and community choice aggregators (CCAs). There has been an overall decline in the amount of fossil-based energy delivered to California customers since 2014. Most of that decline is traceable to a decline in the production of natural gas facilities inside of California, which also dropped by about 20 TWh after 2015.

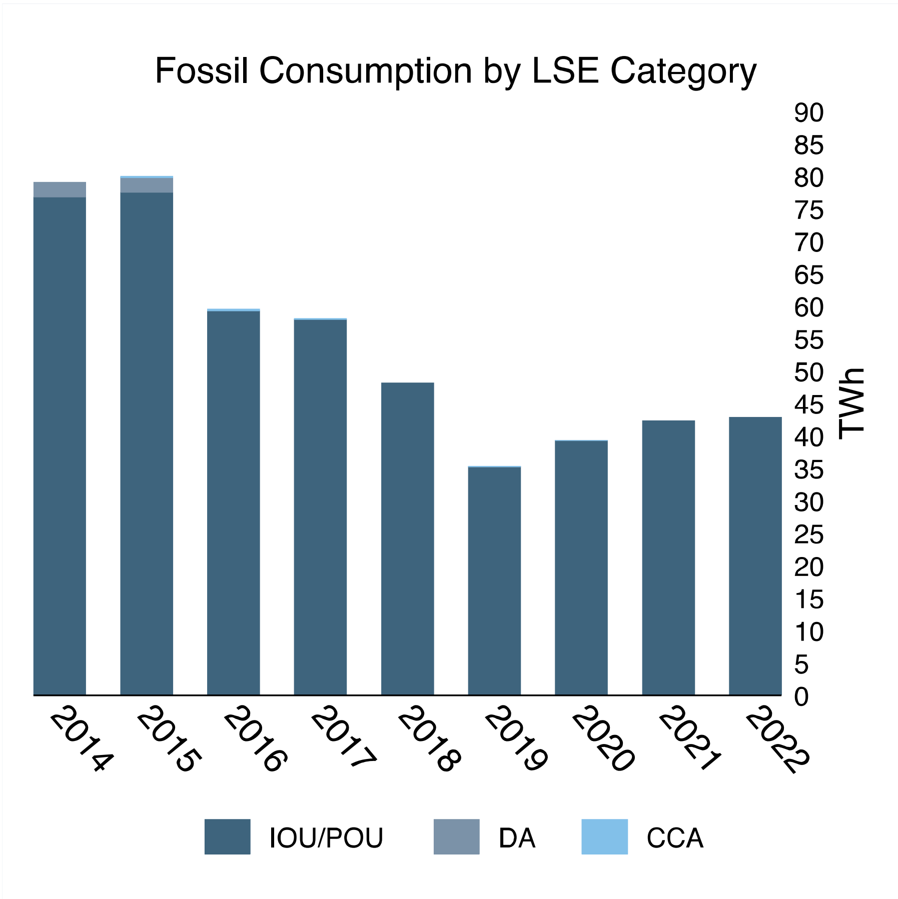

Figure 11: Specified Fossil Energy by LSE Type

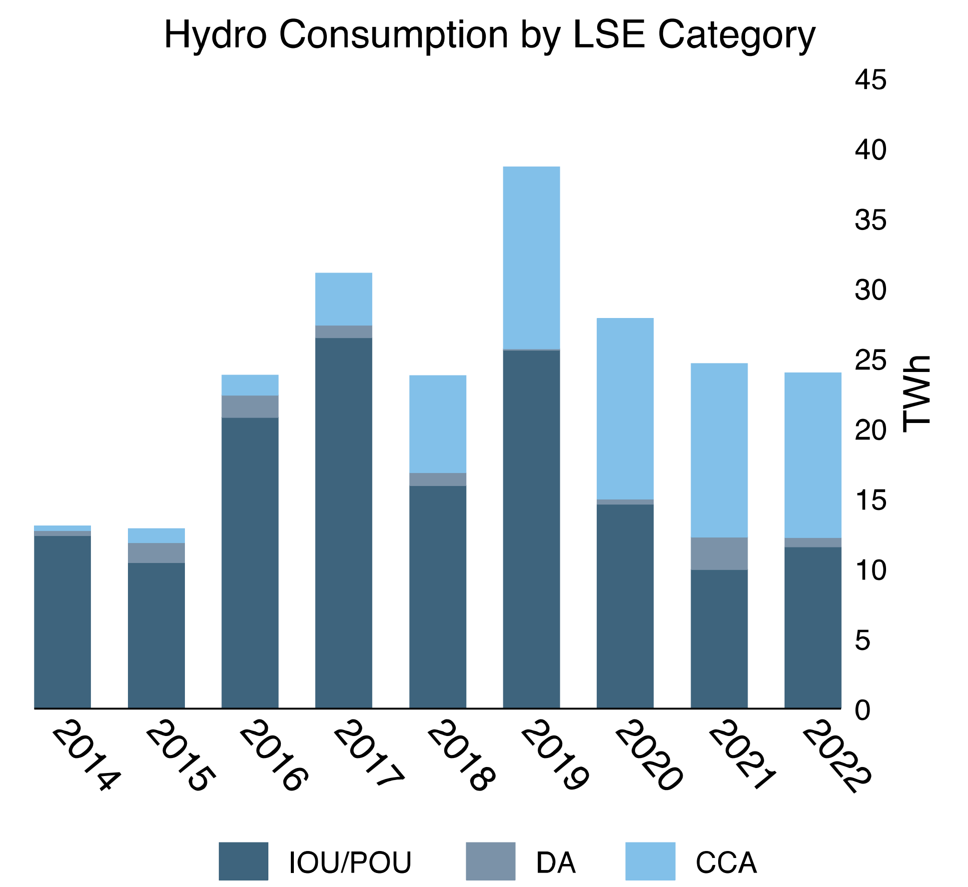

Figure 12: Large Hydroelectric Consumption by LSE Type

Figure 12 summarizes the same information for sources reported as large hydroelectric. Again, these figures are an approximation and do not distinguish between imports and production from California. However, the fluctuations in the hydroelectric energy consumed by California utilities since 2014 mirrors the fluctuations in production from sources within California. The steady increase in hydroelectric energy reflected in the PSDP information reported by community choice aggregators (CCAs) closely follows the increases in hydroelectric imports reported by the California Energy Commission[8] and the increased imports from those sources reflected in the CARB data discussed in previous sections. While not definitive, these data are strongly suggestive of a trend where reduced IOU fossil consumption was replaced by, among other things, increased imports from existing hydroelectric sources in the Pacific Northwest that were increasingly consumed by CCA customers.

[8] Total System Energy Generation 2009-2023. California Energy Commission. https://www.energy.ca.gov/media/7311

9. Summary

This study quantifies the extent to which the reported reductions in emissions from California's electricity imports from 2011 through 2021 have been impacted by emissions leakage in the surrounding western electric grid. This evaluation looks at aggregate outcomes and does not evaluate specific transactions, imports for individual load-serving entities or compliance with regulatory provisions to minimize emissions leakage.

Our empirical analysis presents two complementary estimation approaches. First, we apply marginal emissions estimation methods to quantify the amount of emissions caused by California imports each year and compare multi-year changes in our estimates of the import-driven emissions to the reduction in emissions from imports reported to CARB. Second, we apply an attributional approach to compare trends in the output of reported sources with their observed output overall. Both approaches indicate that roughly half of the 29.6 MMT reduction in emissions from electricity imports could be construed as leakage.

We are not aware of any evidence that any of these changes constituted activities that violate policies on reshuffling of sources. These results do, however, indicate that some degree of leakage is possible within the existing regulatory framework. Our analysis reveals that there are two main sources of aggregate emissions leakage, and that by far the largest single source has been the trend to increase imported energy from pre-existing near-zero carbon resources.

Additionally, there is an intellectual case to be made that the marginal emissions associated with consumption from hydroelectric energy should, in most cases, not be considered zero as it is today. This is because energy consumed on one day forecloses the opportunity to consume it on a later day. When a California LSE imports hydroelectric energy in May, in many cases this energy must be "backfilled" by other sources in the west at some later date. Our contemporaneous marginal emissions estimates account for "instantaneous backfill" but do not directly account for the fact that, when the import source is hydroelectric, this backfill will occur at some later date and time.

A similar issue will become more pressing in the coming years: how to attribute emissions to imports from battery or other short-term storage facilities. Like hydroelectric production, there is an opportunity cost to importing output from batteries, whose lost energy cannot be used to counteract other forms of production in the western grid.

References

Bushnell, James, and Yihsu Chen. "Allocation and leakage in regional cap-and-trade markets for CO2." *Resource and Energy Economics* 34.4 (2012): 647-668.

Bushnell, James, Yihsu Chen, and Matthew Zaragoza-Watkins. "Downstream regulation of CO2 emissions in California's electricity sector." *Energy Policy* 64 (2014): 313-323.

Callaway, Duncan S., Meredith Fowlie, and Gavin McCormick. "Location, location, location: The variable value of renewable energy and demand-side efficiency resources." *Journal of the Association of Environmental and Resource Economists* 5.1 (2018): 39-75.

Cullenward, Danny, and David Weiskopf. *Resource shuffling and the California carbon market*. Environmental & Natural Resources Law & Policy Program, Stanford Law School, 2013.

Fell, Harrison, and Peter Maniloff. "Leakage in regional environmental policy: The case of the regional greenhouse gas initiative." *Journal of Environmental Economics and Management* 87 (2018): 1-23.

Fowlie, Meredith L. "Incomplete environmental regulation, imperfect competition, and emissions leakage." *American Economic Journal: Economic Policy* 1.2 (2009): 72-112.

Fowlie, Meredith, Claire Petersen, and Mar Reguant. "Border carbon adjustments when carbon intensity varies across producers: evidence from California." *AEA Papers and Proceedings*. Vol. 111 (2021).

Holland, Stephen P., et al. "Are there environmental benefits from driving electric vehicles? The importance of local factors." *American Economic Review* 106.12 (2016): 3700-3729.

Lo Prete, Chiara, Ashish Tyagi, and Qingyu Xu. "California’s cap-and-trade program and emission leakage in the Western Interconnection: comparing econometric and partial equilibrium model estimates." *Journal of the Association of Environmental and Resource Economists* 11.2 (2024): 359-402.

Novan, Kevin, and Yingzi Wang. "Estimates of the marginal curtailment rates for solar and wind generation." *Journal of Environmental Economics and Management* 124 (2024): 102930.

Xu, Qingyu, and Benjamin F. Hobbs. "Economic efficiency of alternative border carbon adjustment schemes: A case study of California Carbon Pricing and the Western North American power market." *Energy Policy* 156 (2021): 112463.

Appendix

Examining Impact of Cap-and-Trade on non-CA Dispatch Orders

To quantify leakage, our short-run empirical analysis quantifies the emissions caused by California's imports and compares the changes in these estimates from 2011 to 2021 to the reported changes in emissions attributed to California's imports. Importantly, our approach assumes that the adoption of the Cap-and-Trade Program has not altered the dispatch order of generators outside of California, and thus has not affected which non-CA generators are on the margin at any given point in time. If the Cap-and-Trade Program has altered which generators are on the margin outside of California (e.g., if the Cap-and-Trade Program has caused coal units to move farther up the dispatch order and cleaner natural gas units to move down the dispatch order), then the Cap-and-Trade Program will cause changes in non-CA emissions that will not be captured by our short-run analysis. In this subsection, we examine whether there is evidence of systematic changes in the dispatch orders among the fossil fuel generators in the AZNM, NWPP, and RMPP regions of the WECC.

To examine whether there is evidence of changes in the dispatch order consistent with generators responding to the Cap-and-Trade Program, we first calculate the monthly capacity factor for each fossil fuel generator during each month from 2011 through 2022. To calculate these monthly capacity factors, we aggregate up the hourly net generation (using the reported gross generation from the EPA CEMS data and the corresponding net-to-gross ratio calculated using the monthly EIA 923 data) to the monthly level. We then divide this monthly net generation by the potential monthly capacity (the reported capacity in MW multiplied by the number of hours during the month) to determine the monthly capacity factor ($CapFactor_{i,m.y}$) at plant i during month m of year y.

For each plant, we also estimate the marginal cost ($MC_{i,m,y}$) required to generate an MWh during month m of year y. The marginal cost is comprised of two components. First, we utilize estimates of the non-fuel variable operating costs for coal, natural gas-fired CCGT units, and natural gas turbines. Second, we calculate the variable fuel costs for each unit by multiplying the monthly observed heat rate (the total MMBtus divided by the total net generation) by the corresponding monthly fuel price (which varies by fuel and location). For the coal price, we utilize the EIA's reported average quarterly price of coal delivered to the electricity producers by state. For the monthly natural gas price, we utilize the EIA's monthly reported price of natural gas for electricity generation by state. Importantly, these estimates of the plant-level marginal costs do not include a price on carbon emissions.

Intuitively, fossil fuels with lower marginal costs would be expected to have higher capacity factors. To model this relationship, we estimate the following simple model separately for each month-by-year from 2012 through 2022 and for each of the three non-CA WECC regions (AZNM, NWPP, and RMPP):

$$CapFactor_{i,m,y} = \alpha_{m,y} + \beta_{1,m,y} \cdot MC_{i,m,y} + \beta_{2,m,y} \cdot MC_{i,m,y}^2 + \varepsilon_{i,m,y} \qquad A.1$$

If generators outside of California are not internalizing the carbon price created by the Cap-and-Trade Program, then we would not expect the capacity factors for two generators with the same MC, but different CO2 emission rates, to systematically differ – i.e. we would not expect the residuals ($\hat{\varepsilon}$) from the model above to systematically differ based on the CO2 rates of the given plants. However, if generators outside of California are responding to the carbon price created by the Cap-and-Trade Program, then we would expect the relationship between the plant-level capacity factors and marginal costs to systematically deviate from the expected negative relationship between the capacity factor and the marginal cost. In particular, we would expect coal units to have lower capacity factors than expected (i.e. negative residuals) and cleaner natural gas CCGT units to have higher capacity factors than expected (i.e. positive residuals). To examine whether this is the case, we calculate the average residual ($\hat{\varepsilon}_{i,m,y}$) for each year for coal and CCGT generators in each of the three non-CA WECC regions.

Table 8: Examination of non-CA WECC Dispatch Orders

	Average Capacity Factor Residual by Year					
	AZNM		NWPP		RMPP	
Year	Coal	CCGT	Coal	CCGT	Coal	CCGT
2012	0.067	0.074	0.001	-0.038	-0.052	-0.003
2013	0.006	0.015	-0.003	-0.004	-0.010	0.007
2014	0.008	0.015	-0.005	-0.005	-0.010	0.009
2015	0.072	0.049	0.012	-0.041	-0.029	-0.023
2016	0.061	0.074	0.003	-0.033	-0.037	-0.005
2017	0.041	0.088	-0.011	-0.023	-0.043	0.016
2018	0.059	0.079	0.007	-0.032	-0.040	-0.010
2019	0.006	0.020	0.019	-0.003	-0.011	-0.026
2020	-0.024	0.004	0.033	0.010	-0.002	-0.042
2021	-0.062	-0.013	0.000	0.026	0.006	0.000
2022	-0.022	-0.003	-0.004	0.010	0.002	0.005

From 2012 through 2019, the residuals in the three regions do not display any trends consistent with non-CA generators internalizing the CO2 permit price. In particular, the coal residuals are not systematically becoming smaller (or negative) and the CCGT residuals are not becoming larger (or positive). Focusing on the last two years of the sample (2021-22), we do observe a pattern emerging in AZNM in which the coal units residuals become slightly negative. While this could be consistent with coal units internalizing the increasing CO2 permit price in their operating decisions, it also could be driven by other trends – e.g., growth in solar capacity causing reductions in capacity factors of less flexible conventional technologies. As a whole, the absence of clear trends in the residuals displayed above suggests that there has not been a systematic shift in the dispatch order of fossil fuel units outside of California.

Imputing Hourly Hydroelectric Generation

Importantly, to estimate the model specified by Eq. 5, we need time series of the hydroelectric generation from the non-CA WECC region at the hourly level. However, we only directly observe the hourly hydroelectric output from July 2018 to present (from the EIA 930 data). To overcome this data constraint, we take advantage of the fact that we can observe the monthly aggregate hydroelectric generation from the non-CA WECC region (from EIA 923 data) over our full sample period. To predict how much of the aggregate monthly hydroelectric generation occurred during individual hours within each given month, we first estimate the following model using observations spanning July 2018 through December 2022:

$$\frac{Hydro_{h,d,m,y}}{\overline{Hydro}_{m,y}} = \alpha_{h,m} + \gamma_{h,m} \cdot \frac{Demand_{h,d,m,y}}{\overline{Demand}_{m,y}} + \varepsilon_{h,d,m,y} \qquad (A.2)$$

where $Hydro_{h,d,m,y}$ is the hourly observation of hydroelectric generation in the non-CA WECC region, $\overline{Hydro}_{m,y}$ is the aggregate hydroelectric generation that occurs during the corresponding month, $Demand_{h,d,m,y}$ is the hourly observation of the quantity of electricity demanded from non-CA WECC suppliers (i.e., the non-CA WECC demand plus net exports to California), and $\overline{Demand}_{m,y}$ is the aggregate quantity demanded from non-CA WECC suppliers during the corresponding month. The model specified by Eq. A.2 allows us to predict how much of the observed monthly total hydroelectric output is supplied during a given hour based on (A) systematic daily and seasonal patterns, and (B) correlations between the observed share of monthly hydroelectric that is supplied during a given hour and the share of the monthly aggregate demand that occurs during the corresponding hour. Using the estimates of $\{\hat{\alpha}_{h,m}, \hat{\gamma}_{h,m}\}$, and imposing the assumption that these parameters are stable over the period from 2011 through 2022, we can impute the hourly non-CA WECC hydroelectric generation using the following equation:

$$\widehat{Hydro}_{h,d,m,y} = \overline{Hydro}_{m,y} \cdot \left(\hat{\alpha}_{h,m} + \hat{\gamma}_{h,m} \cdot \frac{Demand_{h,d,m,y}}{\overline{Demand}_{m,y}}\right) \qquad (A.3)$$

where $\overline{Hydro}_{m,y}$ is the monthly aggregate non-CA WECC hydroelectric output (observed from the EIA 923 data over the full sample period), $Demand_{h,d,m,y}$ is the hourly quantity of electricity demanded from non-CA WECC generators (the total load in the non-CA WECC balancing areas plus net-exports), and $\overline{Demand}_{m,y}$ is the monthly quantity demanded from the non-CA WECC generators. Over the period in which we can observe the hourly hydroelectric generation (July 2018 through 2022), the correlation between the predicted hourly hydroelectric output, $\widehat{Hydro}_{h,d,m,y}$, and the actual hourly hydroelectric output is 0.92.

To create the hourly time series of the aggregate output from non-CA WECC fossil and hydroelectric generators ($\tilde{Q}_{h,d,m,y}$) required to estimate Eq. 5, we sum the hourly net fossil generation and the predicted hourly hydroelectric output from Eq. 7.