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Emissions Reductions from Renewable Energy and Energy Efficiency in California Air Quality Management Districts

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EMISSIONS REDUCTIONS FROM RENEWABLE ENERGY AND ENERGY EFFICIENCY IN CALIFORNIA AIR QUALITY MANAGEMENT DISTRICTS

Prepared for: California Energy Commission

Prepared by: Synapse Energy Economics, Inc.

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PREFACE

The California Energy Commission Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

The PIER Program strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following RD&D program areas:

- Buildings End-Use Energy Efficiency
- Energy Innovations Small Grants
- Energy-Related Environmental Research
- Energy Systems Integration
- Environmentally Preferred Advanced Generation
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy Technologies
- Transportation

Emissions Reductions from Renewable Energy and Energy Efficiency in California Air Quality Management Districts is the final report for the Air Emissions Reductions Through Energy and Peak Load Reductions and Renewable Generation project (contract number 500-02-004, work authorization number MRA 026) conducted by Synapse Energy Economics, Inc. The information from this project contributes to PIER's Energy-Related Environmental Research Program.

For more information about the PIER Program, please visit the Energy Commission's website at www.energy.ca.gov/research/ or contact the Energy Commission at 916-654-4878.

ABSTRACT

In California and other states, air quality management districts are considering using energy efficiency and renewable energy to target both criteria pollutants (to meet air quality standards) and greenhouse gas emissions. This report presents a pilot study, designed to quantitatively model the emissions avoided through new energy efficiency/renewable energy programs not already required by state or federal statute. This work used California as a test case, producing an analysis that could theoretically satisfy U.S. Environmental Protection Agency requirements for using energy efficiency/renewable energy in State Implementation Plan compliance.

Synapse Energy Economics used a Western Electricity Coordinating Council-scale production-cost simulation model (PROSYM) to examine the impact of incremental energy efficiency/renewable energy on generation and emissions of oxides of nitrogen (NO_X), sulfur dioxide (SO_2), and carbon dioxide. Sixteen energy efficiency/renewable energy scenarios were tested against a reference "base case," representing the expected structure of Western Electricity Coordinating Council in 2016 under a full implementation of the California 33 percent renewable electricity standard and other energy statutes. The scenarios were comprised of four energy efficiency/renewable energy programs (solar, wind, and both baseload and peaking energy efficiency) enacted in four different California service territories (San Diego Gas and Electric, Southern California Edison, Los Angeles Department of Water and Power, and Pacific Gas and Electric).

It was observed that in many cases, a large fraction of generation was displaced out-of-state, and total NO_X and SO_2 displaced in California tended to be small. Generation displaced out-of-state included coal resources, and therefore resulted in far larger emissions benefits in Western Electricity Coordinating Council regions other than California. The large range of criteria pollutant displacement from energy efficiency/renewable energy programs across California suggests that examining output variance and uncertainty is important, and that both model construct and input assumptions are key.

Keywords: California Energy Commission, energy efficiency, renewable energy, simulation model, displaced emissions, State Implementation Plan, criteria emissions, greenhouse gas emissions, Synapse Energy Economics

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Executive Summary

Purpose

Energy and the environment are inextricably linked. Fossil-fuel combustion is a primary source of pollutants that contribute to unhealthy concentrations of fine particulates, ground-level ozone, and airborne toxics. Both nationally and in California, air districts have successfully reduced criteria pollutants such as oxides of nitrogen (NO_X), sulfur dioxide (SO_2), and fine particulates ($PM_{2.5}$) through end-of-pipe controls. In the face of increasingly stringent air quality standards however, states and air districts have progressively turned toward energy demand-reduction measures and non-emissive sources of energy to meet standards cost-effectively.

In California and other states, air quality management districts are considering using energy efficiency and renewable energy to target both criteria pollutant and greenhouse gas emissions. The U.S. Environmental Protection Agency continues to improve guidance on the use of energy efficiency and renewable energy to meet State Implementation Plan targets, and states and utilities are working to quantify emissions reductions potential of energy efficiency/renewable energy programs.

Synapse Energy Economics conducted research for the California Public Interest Energy Research (PIER) program in two phases. The first phase surveyed existing analytical methods available to assess the energy savings from energy efficiency/renewable energy and identified air district efforts to incorporate energy efficiency/renewable energy into air quality State Implementation Plans. The second phase, presented in this report, is a pilot study to quantitatively model the emissions avoided through new energy efficiency/renewable energy programs not already required by state or federal statute. The goal of the work was to use California as a test case, producing an analysis that could theoretically satisfy U.S. EPA requirements for using energy efficiency/renewable energy in State Implementation Plan compliance.

Approach

Each unit of energy saved by a new efficiency program or supplied by a new renewable energy resource displaces energy from an existing generator (or eliminates the need for a new generator to be built). In most cases, the generating resources that are most readily displaced are fossil-fired; however, the type and location of these resources are not clearly delineated, and can be geographically widespread. In the case of California, the geography of potential generators that might be displaced by new energy efficiency/renewable energy can span the full Western Interconnect (the Western Electricity Coordinating Council)—an eleven-state (and two Canadian-province) region. It is therefore feasible that energy efficiency/renewable energy programs implemented in California could displace generators that do not impinge on California air quality, and even generators that are well outside of state lines. The goal of this research is to identify which resources are displaced by incremental California energy efficiency/renewable energy programs in a future test year (2016), and which regions or air districts can claim a benefit for these energy efficiency/renewable energy programs.

Synapse used a Western Electricity Coordinating Council-scale production-cost simulation model to examine the impact of incremental energy efficiency/renewable energy on generation and emissions of NO_X, SO_2, and CO_2.[1] Sixteen energy efficiency/renewable energy scenarios

[1] In implementing the model, Synapse found significant errors in baseline assumed model emissions rates for criteria pollutants of NOx and SO_2 in California, which would have resulted in emissions up to an

were tested against a reference "base case," representing the expected structure of the California and Western electricity system in 2016 under a full implementation of California's 33 percent renewable electricity standard and other energy statutes. The scenarios were comprised of four energy efficiency/renewable energy programs enacted in four different California service territories. The programs included wind, solar, and both baseload and peaking efficiency programs in San Diego Gas and Electric (SDG&E), Southern California Edison (SCE), the Los Angeles Department of Water and Power (LADWP), and Pacific Gas and Electric (PG&E) service areas.

Previous work in displaced emissions from energy efficiency/renewable energy have almost exclusively focused on using either generic "emissions factors" for either all plants in a region or those which are thought to be on the margin, or on hourly emissions factors, derived from historic data. While these methods have merit both in concept and approach simplicity, they are not simulation models and cannot represent subtle, but important, factors such as transmission constraints, imports, and the economic considerations of generators. This research presents one of the most comprehensive simulation model studies designed strictly for the purposes of evaluating displaced emissions from energy efficiency/renewable energy programs, and is therefore a new direction of research for examining displaced emissions at the operating margin.

In the analysis, Synapse examined potential sources of error and explicitly accounted for "forced outages," wherein generators require emergency or unforeseen maintenance. Forced outages, represented as random events in the model, create potentially spurious results in marginal emissions analyses: the degree to which patterns of displaced energy and emissions are driven by forced outages were estimated and reported.

Results from the model were aggregated into four Western Electricity Coordinating Council regions (California, the Southwest, the Rocky Mountain West, and the Northwest) and into air district "regions" within California.[2] Synapse examined displaced energy and emissions, scaled by the size of the energy efficiency/renewable energy program implemented (i.e., megawatt-hour [MWh] of generation displaced per MWh of energy efficiency/renewable energy implemented, or pounds of emissions displaced per MWh of energy efficiency/renewable energy implemented). The purpose of this scaling is to allow users of the data to examine the potential benefits from variously sized energy efficiency/renewable energy programs.

Results

It was observed that in many cases, a large fraction of generation was displaced outside of California state lines. However, the degree to which program benefits were experienced in California, or even in any air district, were observed to be both a function of the program type and the area of implementation. Figure 1 below shows generation displaced by the sixteen scenarios relative to the base case in 2016, parsed by region and fuel type.

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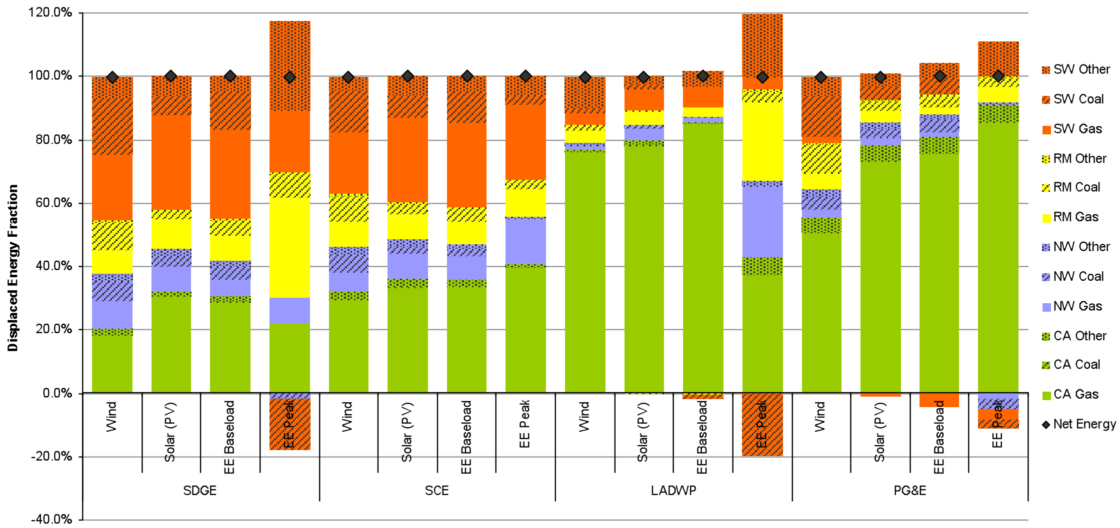
order of magnitude greater in an early test year (2012) than recorded by air districts or the U.S. EPA. Synapse corrected emissions rates from 165 generators in California prior to modeling.

[2] "Air district regions" include larger air districts as well as clusters of smaller air districts for the purposes of examining results.

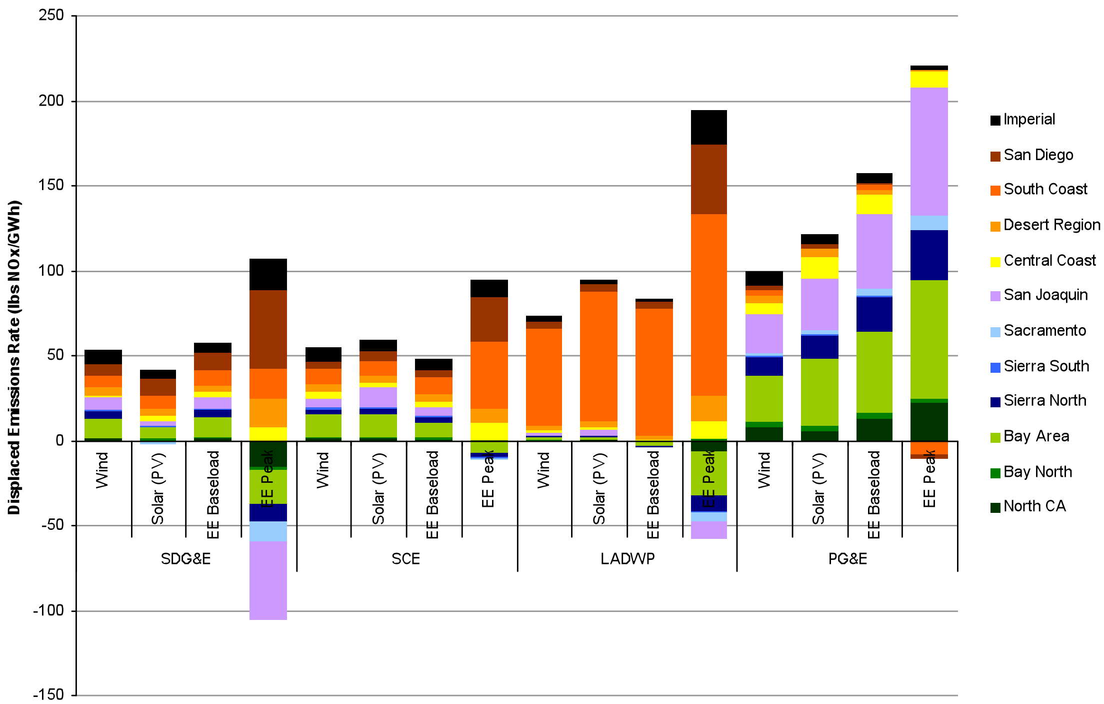
Figure 1: Displaced Energy Fraction (MWh Displaced Generation per MWh of Energy Efficiency/Renewable Energy) by Western Electricity Coordinating Council Region and Fuel Type in 2016, Relative to the Base Case



In this chart, the color of the bars represents the region of displacement (California is in green) and the pattern represents the generic fuel type displaced (solid is natural gas, hashed is coal, and dotted is "other," including biomass and petroleum). The amount of generation displaced is scaled by the amount of generation produced by the energy efficiency/renewable energy program; in all cases, the net generation displaced is equal to the amount of energy produced by the energy efficiency/renewable energy program (i.e., displaced energy fraction = 100 percent). However, the regions and fuel types displaced by the energy efficiency/renewable energy programs are highly variable. For example, programs implemented in LADWP and PG&E tend to displace more resources in California, while programs implemented in SDG&E and SCE tend to displace energy out-of-state generators, and include significant fractions of coal. This out-of-state displacement is a non-intuitive finding, discussed in depth in the Discussion section of the report.

Due to California's cleaner-burning natural gas units, the emissions produced by California generators are very small relative to surrounding states: therefore, total NO_X and SO_2 displaced in California tend to be small. Results of the displaced NO_X emissions rate within California (i.e., emissions represented by the green bars in Figure 1, are shown in Figure 2, below, parsed by air district region. Note that the scale in this figure is in pounds of NO_X per gigawatt-hour (GWh) of energy efficiency/renewable energy.

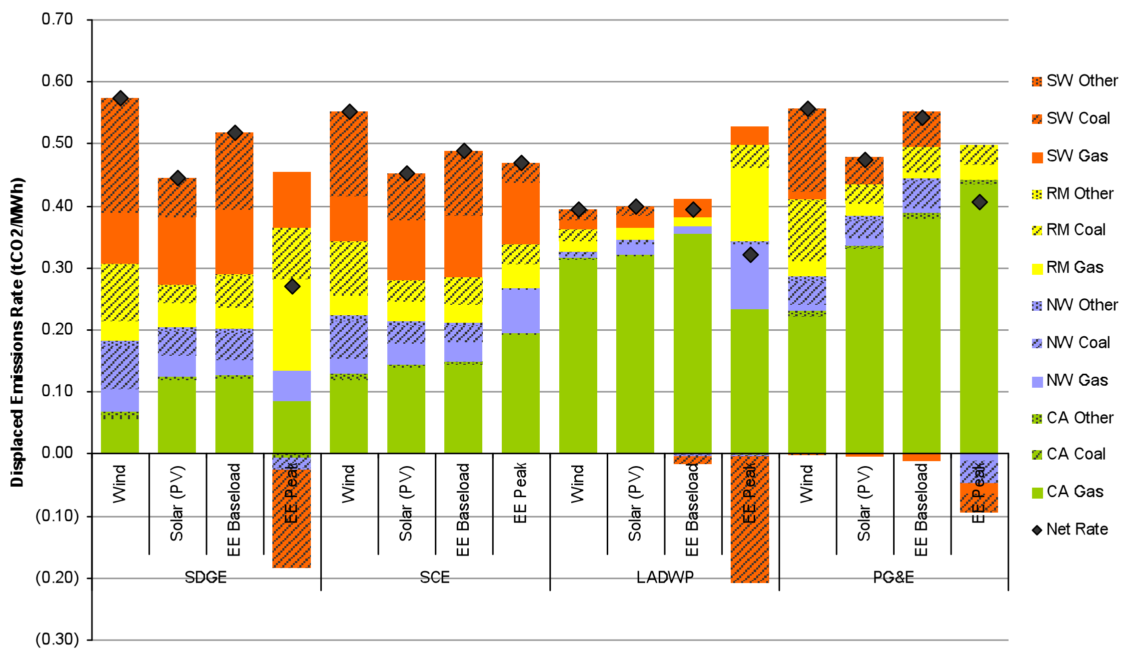
Figure 2: Displaced NO_X Emissions Rate (in lbs NO_X/GWh) by California Air District Region in 2016, Relative to the Base Case



Energy efficiency/renewable energy programs implemented in SDG&E and SCE tend to displace generators throughout California, and have little impact in any given California region. On the other hand, programs in LADWP tend to have a disproportionate impact on South Coast generators, and programs in PG&E territory tend to have a disproportionate impact in northern air district regions. The negative displaced emissions (i.e., increasing emissions) patterns seen in peaking efficiency programs in all four service territories are hypothesized to be an artifact, and are addressed in more depth in the discussion section of this report.

Finally, although energy efficiency/renewable energy in California are found to have a relatively modest impact on California criteria emissions, Synapse finds a more significant impact in displaced CO_2, both in California and from out-of-state coal generators (see Figure 3, below).

Figure 3: Displaced CO_2 Emissions (tons of CO_2 / MWh of Energy Efficiency/Renewable Energy) by Western Electricity Coordinating Council Region and Fuel Type in 2016, Relative to the Base Case



Summary of Conclusions

- **Dispersed emissions benefits:** The Western grid is highly interconnected, and therefore changes in load, generation, or resource availability in California affect generators throughout the entire Western Electricity Coordinating Council system. As a result, criteria emissions benefits from the energy efficiency/renewable energy programs implemented in California are highly dispersed. Further, programs implemented in different parts of California appear to have varying impacts across the Western Electricity Coordinating Council and within California. It is concluded that a comprehensive modeling approach is required to estimate the emissions reduction potential of energy efficiency/renewable energy in a highly interconnected and highly diverse region such as Western Electricity Coordinating Council.

- **Large benefit out-of-state:** This research finds that while California does not necessarily realize significant criteria emissions benefit from energy efficiency/renewable energy programs in State, other regions of the West see significant emissions reductions from demand reductions in California, posing important questions about interstate energy and emissions planning. This out-of-state energy displacement, and particularly the displacement of coal in the Intermountain West, does not conform to conventional concepts about the nature and cost of energy resources in the Western Electricity Coordinating Council region. However, the results consistently show reductions in out-of-state coal, which have higher emissions than California generators, and hence deliver a significant benefit to other Western Electricity Coordinating Council regions.

- **Greenhouse gas benefits:** A notable benefit identified in this analysis is that energy efficiency/renewable energy programs have a large displacement outside of the state, often displacing coal-fired resources in the Rocky Mountain and Southwest regions of

Western Electricity Coordinating Council. Because of this coal displacement, the greenhouse gas benefit of the energy efficiency/renewable energy programs is higher than would be seen were the displacement within California only. In many of the programs, displacing a combination of California natural gas and out-of-state coal (such as in the SDG&E wind scenario) results in a 50 percent increase in GHG emissions benefit (0.6 tons of carbon dioxide [tCO_2]/MWh) relative to displacing in-state natural gas only (such as in the LADWP baseload energy efficiency scenario, 0.4 tCO_2/MWh).

- **Uncertainty in emissions reductions:** Emissions reductions from energy efficiency/renewable energy occur from generating units at the margin, or units which are least economic at any given time. These same units are highly influenced by small changes in electrical dispatch due to forced outages at large units: therefore, modeling research at this scale and detail necessarily requires an extensive and detailed analysis of error and uncertainty. In this research, it was found that uncertainty can equal or exceed the magnitude of displaced energy and emissions, suggesting that all patterns in similar studies should be examined for relevance relative to error and uncertainty. When uncertainty, or noise, exceeds displaced energy or emissions, the results are termed "non-meaningful" in this research. For example, the negative displacement patterns (generation and emissions increase) seen in the results of the peaking energy efficiency programs are, by this definition, non-meaningful.

- **Emissions rate accuracy:** This research found, incidentally, that a small number of generators in California are responsible for a large fraction of the emissions, but that the default model emission rates for these generators were also not based in verified data. Verifying and correcting emissions rates in the model, particularly in a low-emissions region such as California, is critical to a viable and useful result.

CHAPTER 1: Introduction

Background

Energy and the environment are inextricably linked. Fossil-fuel combustion to produce electricity is a primary source of pollutants that contribute to California's exceedances of the fine particulate and ground-level ozone National Ambient Air Quality Standards (NAAQS). Electricity generating plants are also responsible for significant and growing quantities of greenhouse gas emissions. Both nationally and in California, air districts have successfully reduced oxides of nitrogen (NO_X), sulfur dioxide (SO_2), and fine particulate ($PM_{2.5}$) emissions (known as "criteria pollutants") from the power sector through state and local regulations and the federal acid rain program. California's rigorous efforts to control these criteria pollutant emissions have resulted in reductions by over two-thirds since the early 1990s, yet greenhouse gas emissions, which have not been covered by any of these regulations, have continued to rise. In fact, certain policy choices, like end-of-pipe emissions controls for stationary sources, have increased parasitic energy requirements at power plants, leading to a further increase in greenhouse gas emissions.[3]

Along with the success of some air quality regulations, and increasing public awareness of the value of clean air, have come increasingly stringent emissions standards, but also numerous failures to meet existing standards in California and elsewhere. This has led to interest in combining energy and emissions planning efforts in the hope that greater coordination could lead to lower overall emissions. In California and in other states, air districts are using energy efficiency (EE) and renewable energy (RE) to target both criteria pollutant and greenhouse gas emissions. The U.S. Environmental Protection Agency (U.S. EPA) continues to improve guidance on the use of EE and RE to meet State Implementation Plan (SIP) targets, and states and utilities continue to examine the emissions reductions potential of EE and RE initiatives.

The U.S. EPA has issued a host of new federal regulations and standards covering criteria and toxic emissions from the power sector, starting in 2010 and expected to be promulgated through at least 2012. These new regulations dramatically increase the importance of synchronizing state energy and environmental programs,[4] but even in the absence of these new regulations, there are still ample reasons to consider comprehensive energy planning when structuring SIPs. For example, economic energy resource plans considered by state energy offices and Public Utility Commissions (PUCs) may prove to be inconsistent with state or local air district environmental requirements, particularly if (as is usually the case) the public health and environmental impacts of new resources are not fully considered as part of the plant's costs. Similarly,

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[3] Certain emissions control technologies, such as flue gas desulfurization (FGD) for SO_2 control or selective catalytic reduction (SCR) for NOx control, require additional energy to operate; this energy consumption can be considered "parasitic," as it reduces the net output of the generator. Since these energy reductions are not accompanied by an equivalent reduction in CO_2 emissions, the net result is an increase in the CO_2 emissions rate from these criteria emissions controlled generators.

[4] The scope of these new environmental regulations, including the implementation of the regional haze rule, the air toxics or hazardous air pollutants rule, new National Ambient Air Quality Standards (NAAQS), and the newly promulgated Cross-State Air Pollution Rule (effective in eastern states) are changing which power plants require new control equipment and which may cease operations for economic purposes. These environmental rules are, in some cases, dramatically affecting the shape of the energy sector. Similarly, proactive energy planning may help states comply cost-effectively with these new and emerging environmental regulations.

decisions made by environmental regulators may impose economic constraints that turn out to be inconsistent with state or regional energy plans.

In California, the energy planning process at the California Energy Commission (Energy Commission) and California PUC (CPUC) do take environmental policies, regulations, and even intent into consideration; however, these processes have not historically been well coordinated with environmental planning efforts at the California Air Resources Board (CARB), much less specific local air districts. Similarly, the energy planning authority recently granted to CARB to implement the Scoping Plan for AB 32, the Global Warming Solutions Act of 2006, did not have a well-established mechanism to coordinate with the Energy Commission or CPUC. These dynamics can impose unnecessary tension between the Energy Commission, CPUC, CARB, and the air districts.

In the past, a simple and internally consistent resolution between the agencies was to frame emissions reductions through end-of-pipe controls. However, this approach ignores certain important (if more complex to coordinate) options that may protect health and the environment equally as well (or more so), and at lower costs, such as energy efficiency and renewable energy. This two-phased research project emphasizes the environmental benefits of EE/RE and how air districts can consider these benefits in their SIPs.

Quantifying Emissions Reduction Potential from EE/RE

Phase 1 of this research surveyed existing analytical methods available to assess the energy savings from energy efficiency and renewable energy, and identified efforts that had been completed by air districts to date to incorporate the air quality benefits from EE/RE into their SIPs. That phase concluded that few U.S. states had explicitly included EE/RE as an air quality measure, or considered the possibility of doing so in a future SIP. Early efforts to include the air quality benefits from EE/RE suffered from two factors:

- *High transaction costs:* U.S. EPA guidance from 1999 and 2004 provided a path for air districts to include the air quality benefits from EE/RE into SIPs. However, this guidance focused on specific EE/RE measures, and the transaction costs to measure and verify the energy saved or produced by each specific measure was high. For example, avoiding generation might yield an avoided emissions rate of 1 lb NO_X/megawatt-hour (MWh), yet an end-of-pipe solution (such as selective catalytic reduction, or SCR) could yield an order of magnitude steeper results with a significantly simpler analysis.
- *Incomplete understanding about how EE/RE affects generation*: These effects can vary by time of day, season, and location. For example, EE/RE during peak hours may avoid different resources than EE/RE during off-peak hours.

Phase 2 of this research is an attempt to bridge these concerns in California, and to model quantitatively the emissions avoided through EE/RE. The goal of this phase is to use California as a test case and produce an analysis which could satisfy emerging U.S. EPA criteria for the use of EE/RE in meeting SIP compliance obligations.

Air district resources are limited, and the efforts required to quantify emissions reduced through EE/RE are potentially a significant barrier toward using these tools to meet SIP requirements. There are rigorous protocols required to evaluate, measure, and verify energy saved by EE or produced through EE programs, and there are similarly rigorous protocols required to quantify the emissions that could be reduced by EE/RE. From the standpoint of an air district, there are significant economies of scale to be harnessed by engaging in this process at a broader level than an individual district.

Further, the electric system in California and elsewhere is highly interconnected, ensuring that the benefits from EE/RE measures will not necessarily be realized in full in the air district, or even in the state, where the measure is implemented. Due to the scope of the effort and the broad geographical reach of this type of reduction measure, estimating displaced emissions from EE/RE is more effectively considered at a broad scale (i.e., multiple air districts in multiple states, and for multiple measures). This Phase 2 research both establishes a framework and performs analysis allowing the evaluation of EE/RE measures implemented in California, for the purposes of reducing criteria and greenhouse gas emissions.

The timing and focus of this document is developed to inform California air districts and energy planning authorities in advance of emerging U.S. EPA regulatory guidance for criteria emissions reductions.

Regulatory Requirements for Criteria Emissions Reductions

Sections 108 and 109 of the Clean Air Act Amendments of 1990 (CAAA) specify the timing and procedures for U.S. EPA's review of the National Ambient Air Quality Standards (NAAQS). Every five years U.S. EPA is required to review public health and epidemiological data, and based on this evidence, to issue findings on whether the NAAQS should be revised or be kept at the existing level. Once U.S. EPA issues a new or revised NAAQS, the air quality planning process is triggered pursuant to Section 110 of the CAAA. Within three years of adopting a new or revised NAAQS, Section 110 requires states[5] to develop plans that implement, maintain, and enforce limits that will improve air quality to meet and maintain the revised NAAQS. These plans are referred to as *State Implementation Plans*, or SIPs.

During 2010, U.S. EPA reviewed the fine particle ($PM_{2.5}$) and ozone standards, and concluded that existing levels were not adequately protective of public health and the environment. The U.S. EPA was expected to issue a revised ozone standard during July 2010, more stringent than the existing standard of 75 parts per billion (ppb). The U.S. EPA initially indicated that it would delay issuance of a revised ozone standard until December 2010, and then in December, U.S. EPA indicated that it needed additional time to review data, and that the agency was further delaying issuance of the revised standard until July 2011. At the request of the president of the United States, the U.S. EPA decided not to revise the ozone standard at this time.

The $PM_{2.5}$ NAAQS was last revised in 2006, when the 24-hour standard was lowered from 65 to 35 micrograms per cubic meter (□g/m^3). The annual 15 □g/m^3 standard was not changed at that time. The U.S. EPA has indicated that recent data suggest that the annual standard be lowered, and that the agency expects to issue a revised $PM_{2.5}$ annual standard during 2011.

Air districts would be required to submit revised SIPs that contain new or revised control measures to meet U.S. EPA's revised ozone NAAQS by July 2014, and measures to meet U.S. EPA's revised fine particle NAAQS by December 2014 (three years after adoption of the revised NAAQS, per Section 110).[6] This timing requires that air districts complete several steps:

- Analyze what control measures will reduce ozone and fine particle emissions and the efficacy of such measures, including updating emissions inventories and projecting future emissions;
- Where required, update, revise, or adopt new regulations and provisions to enforce them, including holding public hearings and taking public comment on the new or revised rules;

[5] "States" also refers to local air quality planning agencies, where such authority has been delegated.

[6] While considerable uncertainty exists as to the actual date by which U.S. EPA will issue its revised fine particle standard, it is assumed that U.S. EPA will issue it at the end of 2011 or in early 2012.

- Write a description of the regulations and control measures that will result in air quality meeting the NAAQS, and provide technical support for the district's conclusions.

Because government administrative procedure requirements can mean that the rulemaking process stretches out over several months or a year, air districts should begin during 2011 (even prior to the issuance of the revised NAAQS) to assess what control measures are available to help reduce fine particle and ozone precursor emissions. The U.S. EPA has consistently stated that it expects that both the fine particle and ozone NAAQS will be made more stringent. Beginning early is especially important for air districts that may be considering control measures that rely on concurrent implementation with other districts. This would include those energy savings and renewable energy policies that are part of California's statewide efforts to improve air quality and reduce greenhouse gas emissions. Districts can work together to jointly assess the efficacy of the energy savings and renewable energy measures, and to determine what procedures may be needed to evaluate, measure, and verify the energy saved or produced and the resulting emissions benefits.

U.S. EPA Guidance on Emissions Reductions from EE/RE

States can choose one of four routes to incorporate the emissions benefits of energy-saving and renewable energy measures into their air quality control programs. These are identified as follows:

- Future baseline
- Control measure
- Voluntary/emerging measure
- Weight of evidence

Each of the four routes has different requirements and entails different levels of effort to demonstrate the quantity of emissions benefit.

The **future baseline** route requires states to review their existing policies and regulations, and to account for the anticipated impacts in the initial emissions projection, i.e., the baseline. As policies such as renewable portfolio standards (RPS) and energy efficiency resource standards increase in the quantity of energy and capacity involved over time, their displaced emissions affect the state's projection of future pollutant levels. The U.S. EPA has included these state policies in its own emissions projections, using the Integrated Planning Model (IPM). At present, the U.S. EPA has actively coordinated IPM input assumptions with states affected by the 2010 Clean Air Transport Rule, and if these states concur with U.S. EPA's assessment, no additional work is required: the emissions benefits from EE and RE are integrated in U.S. EPA's baseline assessment. While the Clean Air Transport Rule does not apply to California, U.S. EPA's IPM is loaded with state energy efficiency and renewable energy policies such as those included in the EIA Annual Energy Outlook 2010. New policies and existing policies that are amended in the future to increase California energy savings or production[7] would need to be accounted for as part of an adjustment to the future baseline.

The **control measure** route also requires states to review their existing policies and regulations but, instead of including the emissions benefits as part of the future baseline, these benefits are characterized as incremental to the baseline. The requirements to include EE and RE as control measures are the same as those for other measures that states may develop and implement; the

[7] An adjustment to the baseline could entail, for example, a change in RPS requirements or timing or new efficiency standards, implemented after the U.S. EPA completes modeling.

criteria for these reductions are that they be quantifiable, real, surplus, enforceable, and permanent.

The requirement that measures be "quantifiable" and "real" means that the emissions savings must be evaluated and verified over time. "Surplus" means that the emissions reductions must not be currently relied on to meet NAAQS. Qualifying allowances from energy-efficiency that are captured in state cap-and-trade programs must be forfeited in order to be certified as emissions reductions. An "enforceable" emissions reduction has an originating and tracking organization, responsible for assuring the energy savings from the energy-efficiency activities actually occur, and that the methodology used to calculate the resulting emissions savings is credible and replicable. For energy-efficiency, the air quality agency must be able to either independently determine such emissions savings or rely upon the program administrators responsible for ensuring those emissions reductions occur. "Permanence" refers to the savings persisting throughout the life of the energy-efficiency program or measure.

For EE and RE as SIP control measures, another agency besides the air quality agency, such as the state's utility commission, may be the responsible enforcement authority. Having a state utility commission as the responsible agency is acceptable to U.S. EPA as long as that state agency has the ability to issue penalties for non-compliance and to order corrective actions to be expeditiously completed. Also, states are responsible for making up any gaps in emissions benefits from EE/RE, just as for any SIP control measure.

The **voluntary/emerging measure** route refers to EE/RE programs that may have future effective dates, are just beginning implementation, or are not required by a state regulation or statute. The U.S. EPA will give provisional SIP credits to states that wish to include the emissions benefits of voluntary/emerging measures in their air quality program. The process to calculate the benefit of these programs is similar to that described above for the control measure route. However, since the emissions benefits are based on projections rather than upon evaluation of past programs and actual data, U.S. EPA is likely to discount the quantity of provisional SIP credit. The specific discount will be based upon negotiations with the responsible state agency. Also, the state must commit to review the EE/RE measures at least once every three years, and to evaluate their efficacy. Any gaps or deficits in the actual reductions compared to the provisional credit granted by U.S. EPA must be remedied.

Finally, the **weight of evidence** route requires a modeling analysis that quantifies differences between a baseline and a state's air quality programs or regulations to attain National Ambient Air Quality Standards. The U.S. EPA recommends that states also complete additional analyses to further prove NAAQS attainment. Where the results of the additional analyses differ from the preliminary attainment demonstration, states may qualitatively describe why U.S. EPA should base its approval on both the initial analysis and the additional work the state has completed. The additional analyses attempt to prove that a state will attain NAAQS, based on a preponderance of evidence, despite modeling results that may reflect otherwise (i.e., showing that the state is close to attainment). Energy efficiency and renewable energy measures can be included as part of this weight of evidence. Their inclusion can give the state a bit of an insurance policy that the anticipated emissions reductions will occur, and over the expected time period.

The state does need to calculate the expected level of emissions reduction that will occur from the EE/RE measures. However, the state must complete a review at least once every three years to evaluate the emissions benefits from the included EE/RE policies, and to make up any gaps or deficits that occur.

Purpose of Project Relative to U.S. EPA Guidance

This project provides the air districts with the means to calculate the expected benefits from incremental efficiency and renewable energy policies, i.e., the ability to utilize a **control**

measure standard. As such, the baseline chosen for this research already *includes existing efficiency and renewable energy policies* that are required by statute by or through a test year, 2016. This project specifically examines incremental EE/RE above and beyond those which are required by statute; in doing so, the project assumes that in the baseline, aggressive California EE and RE policies (such as the 33 percent RES associated with the AB 32 law) are well into implementation.

Synapse came to an agreement with a program advisory committee (PAC), comprised of U.S. EPA, air district, and Energy Commission members, that the project would examine emissions benefits of incremental EE and RE programs *not* currently required by law as an additional mechanism to capture emissions reductions. There are compelling questions associated with the expected or likely emissions benefits of the existing California statutes, but this project is focused on additional programs that can be implemented by air districts to meet state and federal air quality regulations.

Ultimately, which of the four routes outlined above is to be chosen is an air district-level decision. Different districts may choose different routes for how EE and RE benefits are to be included, even if the districts abut one another. The route chosen will likely relate to the staff resource capacity at a district. A district could choose to examine the benefits of California's existing RPS and energy efficiency requirements as part of a future baseline, and utilize U.S. EPA assistance to examine those benefits. The district can then select one of the three other routes to account for the benefits of future programs (such as additional EE in a local district); this research provides a pilot study to illustrate a rigorous control measure approach.

Modeling Emissions Reductions from EE/RE

Phase 2 of this work emphasized electric system impacts from EE/RE. As detailed in the next section, Synapse used the PROSYM electric system dispatch model used by the Energy Commission (and also by many utilities and system planners) to determine how new EE/RE initiatives would affect electricity output by location/generating plant, season, and time of day. The modeling approach is consistent with the methods U.S. EPA applies nationally to evaluate potential time- and location-varying air quality benefits from EE/RE.

The main body of this document details the methodology and results of this modeling effort. The accompanying **Data Annex**, an Excel workbook, is intended for use by air districts or other parties to evaluate the air district, state, and regional emissions benefits of EE/RE. This document provides detail not only on the actual emissions reductions expected from specific EE/RE load shapes, but also how these particular EE/RE measures affect energy dispatch throughout the Western Interconnect (also known as the Western Electricity Coordinating Council region, or WECC). The purpose of providing this detail is to illustrate how energy, emissions, and dispatch are coordinated throughout the West, and provide a degree of insight into how various regional environmental policies might be realized through changes in California's energy demand.

This report is organized into the following sections:

- **Modeling Framework** discusses the heterogeneous structure of the Western Interconnect and California's role in an electric grid spanning 11 states and parts of Canada and Mexico; the electricity dispatch model used for modeling EE/RE; and the EE/RE scenarios modeled in this analysis.
- **Analytical Framework** details how results from this analysis are parsed to examine changes in generation and in NO_X, SO_2, and CO_2 emissions; how a user should interpret results in terms of impact of EE/RE on a state, regional, and air district level; and the role of random error and uncertainty in the results presented here.

- **Results** steps through individual analyses of displaced energy and emissions, focusing on principal findings and important caveats at the state, regional, and air district level; detailed results for displaced energy and emissions at all scales of analysis are found in the accompanying **Data Annex (**an Excel workbook).
- **Discussion** highlights unusual or unexpected findings, details important caveats and assumptions in the model and model architecture, and draws conclusions based on the analysis.

CHAPTER 2: Model Framework

Modeling Basis

To determine the impacts of EE/RE on emissions in a future year, Synapse used a utility scale model of the Western Interconnect to examine generation and emissions in a "base case" and in several scenarios, representing incremental EE and RE programs above and beyond existing statutory requirements. Synapse chose a test year of 2016 to examine these benefits. The following sections describe the geography of the region, the concept and execution of economic dispatch used in this research, as well as the base case and scenarios used to evaluate emissions benefits.

The Western Interconnect

Displaced energy (generation) and emissions in California cannot be examined outside the context of the much larger Western Interconnect, also demarcated as the Western Electricity Coordinating Council (WECC) region. The WECC region includes California, Oregon, Washington, Idaho, most of Montana, Wyoming, western South Dakota, Colorado, Utah, Nevada, most of New Mexico, the El Paso region of Texas, Arizona, Northern Baja California, Mexico, and the Canadian provinces of Alberta and British Columbia (WECC 2011). The WECC region as defined in this report can be seen in Figure 4.

Figure 4: Western Electric Coordinating Council (WECC) and Analysis Regions

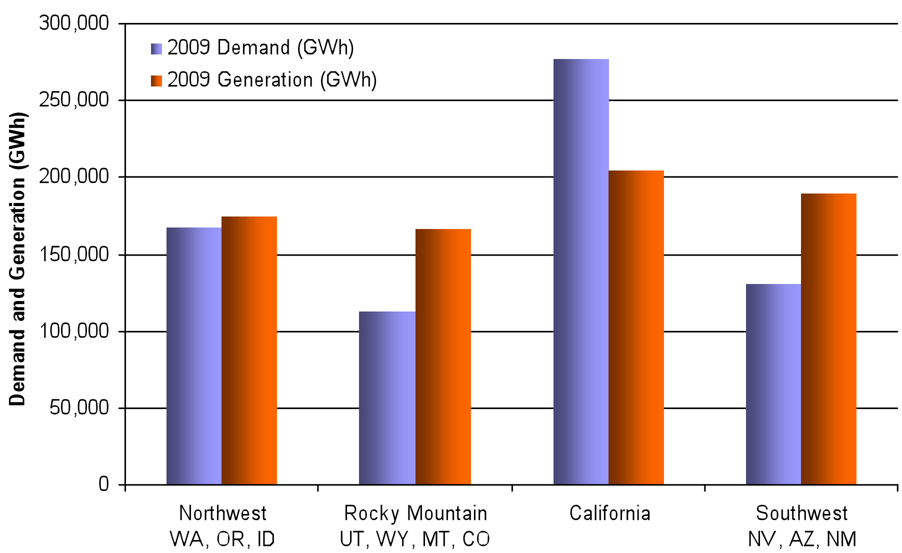
Source: NERC 2011

The WECC region is highly interconnected electrically throughout the West. The electrical grid structure in the West is comprised of high-capacity transmission that runs primarily in two directions: from the Rocky Mountain region (RM: Utah, Montana, Wyoming, and Colorado) to the Northwest (NW: Washington, Oregon, Idaho, Northern Nevada, British Columbia, and Alberta), and from the Southwest (SW: Southern Nevada, Arizona, and New Mexico) into California. There is also significant transfer capacity from the Northwest to California, and between northern and southern California. Much of the electricity which serves California, and therefore many of the emissions associated with California electrical consumption, are served from generators that lie outside of state lines.

The least expensive generation in terms of direct generating cost (i.e., not including either capital costs or environmental costs) lies outside of California> It includes coal generation in Utah, Wyoming, and Montana and hydropower in the Pacific Northwest and Canada.

The relationship between generation and electricity use in the Rocky Mountain region, the Northwest, and California is complex and important to understanding California's energy picture. In 2009, the Rocky Mountain region and the Southwest produced approximately 150 percent and 145 percent more energy, respectively, than these regions required to meet their own demand needs. In the same year, California imported 25 percent of its electricity from other states in the West, while the Northwest remained approximately energy balanced, on net.[8] The overall balance by region in 2009 is shown in Figure 5.

Figure 5: Generation and Demand Balance in the Western States of the WECC [8]



Approximately 70 percent of the electricity in the Northwest states (in 2009) is produced from hydroelectric sources; this electricity source is seasonally dependent on spring runoff, which continues through the summer. In the spring and early summer, when hydroelectric energy is abundant, the Northwest supplies energy to California. In autumn and winter, when the rivers

[8] Author calculations from 2009 U.S. Department of Energy (DOE) Energy Information Administration (EIA) Forms 923 (Page 1) aggregated net generation and 861 (File 2), aggregated total sales by state.

run low, the Northwest imports significantly more energy from the Rocky Mountain region, and supplies much less to California (WECC 2009).

Economic Dispatch

The displacement of generation and emissions from EE/RE is fundamentally a function of economic dispatch. Economic dispatch governs how most generating units in an interconnected electrical system are run: the units with the least expensive operating costs (fuel and operations) are typically dispatched first, and increasingly expensive units are then dispatched to meet load requirements, subject to transmission availability. The last unit, or cohort of units, dispatched to meet load in a particular area are called the *marginal units:* the last to come online, they would also be the first to be taken offline if load is reduced. A displaced energy and emissions analysis is therefore usually an analysis of only the marginal units in the system: as demand is increased or decreased due to EE/RE, it is the marginal units that respond.

In the WECC region, units with very low running costs at the base of the supply curve, i.e., those least likely to be marginal, are nuclear, hydroelectric, solar, wind, and geothermal generators. These resources, with high fixed costs but low operating costs, are typically dispatched to run whenever they are available. Large hydroelectric facilities with reservoirs are partially dispatchable, but can be optimized to deliver more power closer to times of peak usage under some circumstances. Coal units, particularly in the West, are relatively inexpensive to fuel and operate, and are also dispatched early in the loading order. Finally, natural gas units of various sorts (steam, combined cycle, and turbines) have higher running costs, and make up a majority of the marginal (also called load-following) units in WECC. Some oil, petroleum, and jet fuel units are reserved for very high peaks, and can be on the margin a few hours of the year.

As a rule, EE/RE displaces generation and emissions from units at the margin; therefore, it is expected that most of the reduced generation and subsequent reduced emissions will be derived from natural gas. However, a certain amount of displacement will occur for coal or other dispatchable resources, depending on the operational details of the EE/RE resource.

As described above, the WECC region is highly interconnected and geographically heterogeneous, and contains important transmission and operational constraints that strongly affect the displacement of generation resulting from EE/RE. For this reason, a dispatch model is required to take into account transmission constraints, along with and more complex behavior such as capacity reserves and voltage support. For the purposes of this research, an industry standard model, PROSYM, is utilized.

Dispatch Model

Synapse chose to utilize the PROSYM model to maintain consistency with approaches and assumptions utilized by the Energy Commission for the purposes of modeling in the 2007 and 2009 Integrated Energy Policy Reports (2009 IEPR) (CEC 2009). The PROSYM model is a commonly utilized production cost model, designed to optimize dispatch to achieve a lowest cost price of electricity on an hourly basis. The model takes into account fuel prices, individual unit constraints such as heat rate, ramping time, and maintenance requirements, as well as transmission linkages and constraints. Given a series of constraints and requirements, the model solves for the least-cost dispatch at any given time.

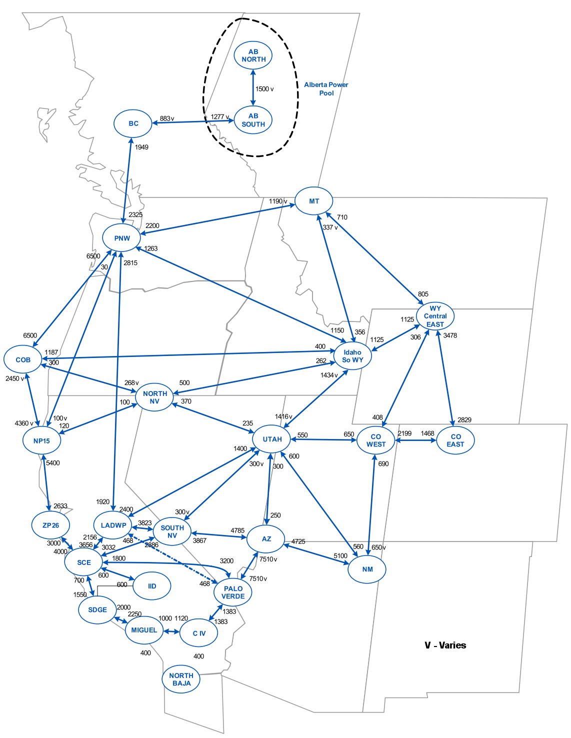
The PROSYM model has been used extensively in the electric industry, including by some independent system operators (ISOs), to evaluate likely system behavior; evaluate transmission and generation alternatives; and predict future emissions, costs, and prices. This type of model is useful both for estimating the costs of generating or obtaining electricity, and examining how different units are dispatched based on changes in the system. In this case, Synapse used the model to evaluate how different units with different emissions characteristics are dispatched given changes in renewable energy and efficiency penetration.

Topology

The model provides a fairly flexible framework to implement different existing or theoretical electrical systems, including generation, transmission, and load (demand) zones. Collectively, the mapping of these structures, either existing or theoretical, is referred to as a “topology.” Synapse utilized default parameterizations for the WECC system as supplied by the vendor, Ventyx, and as modified by the Energy Commission for the 2009 IEPR. Characteristics of existing units were generally consistent with vendor assumptions, with the exception of expected retirements or repowered plants as assumed by the Energy Commission, and significant changes to the emissions rates of generators in California, as described below and extensively in **Appendix A**.

The model topology is identical to that used by the Energy Commission for the 2009 IEPR. The model utilizes transmission zones, which are geographical areas that contain both generation sources and load. At this scale of aggregation, the zones represent regions in which transmission is not constrained (i.e., it flows freely between generation and load). The zones are connected by transmission pipelines that represent aggregations of physical interregional transmission capacity. The model topology for the WECC region is shown in Figure 6 below.

Figure 6: Ventyx PROSYM Topology of WECC



Transmission allows for low-cost resources from neighboring zones to be chosen over local generation sources, including congestion and wheeling charges. However, if the line is fully loaded, then more expensive, local generation sources are used. Within California, the lines that maintain a high utilization rate originate from the Northwest and from Idaho to Northern California, from Utah to Southern California, and between SCE and SDG&E.

In PROSYM, California’s electric grid is represented as seven interconnected zones; these are Los Angeles Department of Water and Power (LADWP), San Diego Gas and Electric (SDG&E),

Southern California Edison (SCE), and Northern California (primarily Pacific Gas and Electric, PG&E),[9] Imperial Irrigation District (IID), California Oregon Border (COB), and IV-NG.

Regions of Interest

Incremental New EE/RE Resource Zones

Synapse focused on new EE/RE resources in the service territories of four primary utilities for this analysis: LADWP, SDG&E, SCE, and PG&E. Each of these utilities is represented in the model as an independent zone. The zone titles serve as shorthand: often the zones include multiple smaller utilities and municipalities as well. The major zones of interest for this research are:

- The **San Diego Gas & Electric (SDG&E)** zone of the model is comprised solely of the SDG&E service territory. In PROSYM, SDG&E is connected to SCE and IID with medium-scale transmission lines.
- The **Southern California Edison (SCE)** zone in the model is comprised of not only the SCE service territory, but also the service territories of Anaheim Public Utilities Department, Department of Water Resources – South, Metropolitan Water District of Southern California, Pasadena Water and Power Department, Riverside Utilities Department, and Vernon Municipal Light Department. SCE is highly connected to the surrounding zones in the model, and has direct lines to Northern California, LADWP, Southern Nevada, Palo Verde, IID, and SDG&E.
- The **Los Angeles Department of Water and Power (LADWP)** area in the model is primarily comprised of the LADWP service territory, as well as Burbank Public Service Department and Glendale Public Service Department. In the model, the LADWP zone is connected to the Northwest and Utah via a dedicated direct current line as well as large-scale transmission into Southern Nevada and SCE.
- The **Pacific Gas & Electric (PG&E)** zone contains the service territory of PG&E, as well as the service territories of Department of Water Resources – North, Modesto Irrigation District, Northern California Power Agency, Redding Electric Department, Sacramento Municipal Utilities District, Santa Clara Electric Department, Turlock Irrigation District, and Western Area Power Administration – Mid Pacific. This zone is connected to SCE and COB (and therefore the Northwest) with large-scale transmission lines, and to the Pacific Northwest and Northern Nevada with smaller-scale transmission lines.

WECC and Air District Region Definitions

To examine generation and emissions impacts, Synapse delineated four WECC-wide regional zones and twelve air district zones, comprised of one to many air districts, depending on size and location.

The four WECC-wide regional zones include California (CA), Northwest (NW), Rocky Mountain (RM), and Southwest (SW); see Figure 4 for a map. The Northwest is made up of Oregon, Washington, British Columbia, Alberta, Idaho, and northern Nevada; the Rocky Mountain region contains Montana, Utah, Wyoming and Colorado; the Southwest includes Arizona, New Mexico, and the El Paso region of Texas.

California has thirty-five air districts. Many of these districts are small, and have few stationary sources of emissions. For this study, these small districts have been aggregated into zones to increase the accuracy and reduce the margin of error. The aggregations are shown in Table 1.

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[9] In the model, PG&E is primarily encompassed by a transmission hub, NP15.

Table 1: Air District Aggregations into Air District Zones Used for this Analysis

Air District Zone	Air District	Air District Zone	Air District
North CA	Lassen County APCD	Sierra South	Amador County APCD
	Modoc County APCD		Calaveras County APCD
	North Coast Unified AQMD		El Dorado County APCD
	Shasta County AQMD		Mariposa County APCD
	Siskiyou County APCD		Tuolumne County APCD
Bay North	Colusa County APCD	Sacramento	Sacramento Metro AQMD
	Glenn County APCD	San Joaquin	San Joaquin Valley APCD
	Lake County AQMD	Central Coast	Monterey Bay Unified APCD
	Mendocino County AQMD		San Luis Obispo Co. APCD
	Northern Sonoma Co. APCD		Santa Barbara County APCD
	Tehama County APCD		Ventura County APCD
	Yolo/Solano AQMD	Desert Region	Antelope Valley AQMD
Bay Area	Bay Area AQMD		Great Basin Unified APCD
Sierra North	Butte County AQMD		Kern County APCD
	Feather River AQMD		Mojave Desert AQMD
	Northern Sierra AQMD	South Coast	South Coast AQMD
	Placer County APCD	San Diego	San Diego County APCD
		Imperial	Imperial County APCD

Individual generators in California were mapped into air districts via ZIP code affiliation, or closest city or town (CARB 2010a). Many, but not all, individual generators in the PROSYM model are tagged with ZIP codes, however, accuracy was found to be variable. For all California generators, a federal code (ORISPL) identifying the plant at which the generator resides was located using the name and service region of the generator. These codes were then associated, through a federal database, to ZIP codes, municipalities, and specific latitude-longitude locations. Using ZIP codes first, municipalities second, and map-checking specific coordinates when required, Synapse mapped each California generator to a specific Air District. Using the lookup table above, the generators were mapped back into air district regions. Demand response generators (such as interruptible load) were not mapped into air districts.

Emission Rates Corrections

This analysis was scoped to examine the results of locally increasing renewable energy and energy efficiency on emissions at the air district scale. To achieve improved accuracy, Synapse examined baseline emissions as estimated by the model in a test year, 2012, and compared these emissions to other data sources, including the U.S. EPA's Continuous Emissions Monitoring System (CEMS) database and the U.S. EPA's Emission and Generation Resource Integrated Database (eGRID). It was found that:

- a small fraction of generation in California contributed to a vast majority of emissions of SO_2 and NO_X, and
- the assumed emissions rates for these generators were generally incorrect, overestimating emissions of SO_2 and NO_X by anywhere from 20 percent to several orders of magnitude.

Synapse corrected the emissions rates for 120 existing fossil and biomass units in California, and 45 fossil and biomass-fired units expected to be built by the 2016 model year. The type, method, and specific changes made to generators are given in **Appendix A**. In general, the most problematic units in the model were high-emissions units that are not required to submit emissions information to the U.S. EPA CEMS system. The most notable problems occurred at industrial boilers which generate grid-available electricity (cogenerators); despite the changes made to very high emissions rates, these units still produce a vast majority of stationary source SO_2 emissions in California (see Tables A-3 and A-4 in Appendix A).

Emissions of NO_X and SO_2 before and after correction are given in Table 2, characterized by fuel type. Three-quarters of natural gas generators report to the U.S. EPA CEMS dataset (labeled below). No other fuel types within California are required to report to the CEMS system. It is notable that of fossil and biomass units, only the natural gas units which report to the CEMS system are close to accurate in the default model framework.

Base Case and EE/RE Scenarios

The California Energy Commission used PROSYM to model California energy policy and western dispatch through 2020 for the 2009 Integrated Energy Policy Report (IEPR) (CEC 2009). By agreement with the Energy Commission, Synapse used these Energy Commission model runs and assumptions as a baseline to retain internal consistency between Energy Commission assumptions and the current study. Synapse adopted the Energy Commission's assumed build-out to 2016, and created a base case from two Energy Commission cases compliant with California Assembly Bill 32 (AB32). The Energy Commission data includes its assumptions on of renewable energy and energy efficiency pursuant to AB32, the once-through cooling law, and an updated demand forecast.

Table 2: Aggregate Emissions Rates of NO_X and SO_2 by Unit Categorization, in California only, Before and After Adjustment (2012)

	Generation (GWh)	NOx (tons) Pre-Adjustment	NOx (tons) Post-Adjustment	SO_2 (tons) Pre-Adjustment	SO_2 (tons) Post-Adjustment
Coal	2,699	7,448	1,468	12,593	3,376
Natural Gas (in CEMS)	55,160	2,481	2,136	129	127
Natural Gas (not in CEMS)	23,328	24,250	8,556	74	74
Petroleum	1,322	3,806	871	58,013	5,337
Fuel Oil	0	1	1	1	1
Biomass	2,426	1,498	1,084	9	9
Refuse	414	752	680	-	-
Wood	3,293	5,907	3,990	-	-
Future Generation	15,170	4,020	3,559	26	25
Non-Emitting	113,365	-	-	-	-
Total	**217,177**	**50,162**	**22,343**	**70,844**	**8,949**
U.S. EPA Estimate for California	**199,925**	**22,302**		**13,577**	

Base Case

The purpose of a base or reference case is to provide a baseline from which to evaluate the impacts of particular strategies or programs. This research evaluates the potential for incremental emissions reductions in California from EE/RE programs *relative* to assumed existing conditions in a future year. Because the research is specifically oriented to *additional* and *incremental* EE/RE above and beyond that which is required by statute (i.e., renewable and efficiency standards), the research utilizes a base case in which fairly aggressive, yet statutorily required EE/RE has already been implemented.

The Synapse base case is an expansion and combination of Energy Commission-estimated resource expansion cases in the year 2016, assuming a full implementation of several existing laws and regulations, discussed below. The year 2016 was chosen to represent a near-term year which would potentially fall within the window of the next California SIP for emissions reductions. The year is close enough to the present such that the system is likely to look analogous to today's electrical grid (with some marked changes);[10] however, 2016 is far enough out that additional EE/RE programs might be feasibly implemented.

[10] The Western Interconnect is a changing electrical grid. New transmission, large new renewable energy projects, potential retirements of existing generators, and a potential regional price on carbon dioxide are all likely to change the shape of WECC over the next decade. However, for the purposes of this study, not

The base case meets a best understanding of several California regulations that were enacted prior to or during the study period.

- **Renewable Electricity Standard under AB 32 (33 percent** Renewable Electricity Standard [RES]**)**: The Energy Commission modeled a best understanding of the evolving rules emerging from AB32 (the California Global Warming Solutions Act of 2006) and the resource build-out that would be required to meet the RES required by the law: 33 percent renewable energy by 2020. A vast majority of new renewable energy added by the Energy Commission in the resource build-out to 2016 appears in California; at the time of the modeling, it was unclear if the RES would require new resources in-state or allow renewable energy credit trading out-of-state. As of January 13, 2011, it was determined that 25 percent of new renewable energy can be built outside of California (CPUC 2011a). It is unclear if this ruling would markedly affect the results of the model as implemented in the Energy Commission build-out assumptions.
- **Energy efficiency requirements under AB 2021:** Assembly Bill 2021 of 2006 requires a 10 percent reduction in forecasted energy consumption in California over a ten-year period; in 2008, the CPUC created an eight-year compliance plan for energy efficiency in the state from 2012 to 2020 (CPUC 2011b).
- **Cooling water intake structures:** In May 2010, the California State Water Board adopted the Use of Coastal and Estuarine Waters for Power Plant Cooling policy (California State Water Control Board 2010). This policy requires that power plant cooling structures reflect the "best technology available" for minimizing adverse environmental impacts, consistent with California's interpretation of the federal Clean Water Act Section 316(b). The California policy effectively requires that 17 natural gas-fired power plants and both nuclear stations in the state re-permit once-through-cooling (OTC) structures, which are likely to be noncompliant with the regulation. Based on its early understanding of this policy, the Energy Commission has assumed in its modeling that all OTC generators will be repowered as new combined-cycle and combustion turbine natural gas plants..

The base case does *not* account for any changes made in the WECC region to comply with new Clean Air Act Regional Haze Regulations ("BART") or the Air Toxics Rule ("Utility MACT"), as the implementation of these rules were still evolving or not yet proposed at the time of the research.

Other changes made by the Energy Commission include modified transmission capacity to accommodate the changing balance of California resources, and zero emissions costs for SO_2, NO_X, and CO_2 (see Discussion for details and additional assumptions.) Using the Energy Commission data ensured that the underlying base assumptions for this analysis were the same and that the results would be comparable to Energy Commission modeling efforts.

Two main Energy Commission cases were used as the basis for this analysis: (1) a scenario in which California meets the AB32 law primarily by building new wind resources, and (2) the law is met primarily with solar resources instead of wind. These cases were called "High Wind" and "High Solar" cases, respectively. To meet the 33 percent RES, the Energy Commission incrementally added further wind and solar resources. The future economics of wind versus solar are unclear, and these two extreme cases illustrate how the future would look with just one or the other resource available to meet the RES.

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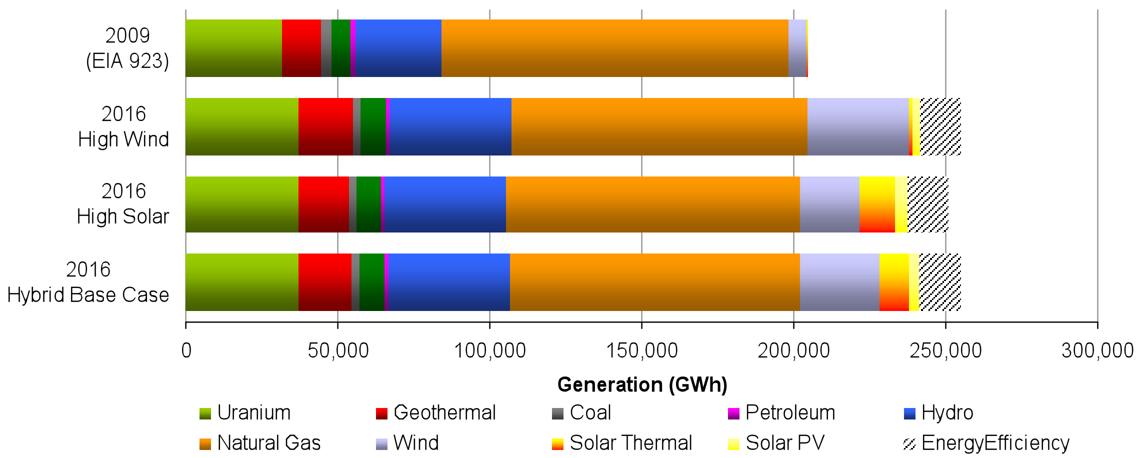
all of these changes can be modeled without a far more extensive process and broad-scale assumptions. Synapse used Energy Commission assumptions of the likely impacts of California energy policy in 2016 to guide this analysis.

With input from the Program Advisory Committee, Synapse determined that, in the absence of additional information about the evolution of the RES market in California, a reasonable Base Case would be halfway between the High Wind and High Solar cases. A hybrid base case was created that blended the High Wind and High Solar cases by taking approximately 50 percent of the wind resources and 50 percent of the solar resources from High Wind and High Solar, respectively. The differences between the High Wind and High Solar cases and the Hybrid Base Case can be seen in Figure 7 below. In 2016, the State of California is on the trajectory toward 33 percent renewables; the Hybrid Case shows approximately 27 percent of energy within California being generated from renewable sources. For more information on how the Hybrid Base Case was created, please see **Appendix B.**

Figure 7: Generation by Fuel Type in 2009 (Recorded), and 2016 in Three Modeled Cases.[11]



Energy Efficiency and Renewable Energy (EE/RE) Scenarios

Once the Hybrid Base Case was established, Synapse added various scenarios; the scenarios incrementally add EE/RE to the Hybrid Case such that the displaced emissions from EE/RE on top of the baseline scenario can be determined.

These incremental EE/RE measures are designed, in this case, to represent load shape "endmembers," where each type had a unique, if not completely realistic, impact on the grid at different hours of the day. Each of the programs chosen has a different temporal pattern (peak or off-peak coincident, flat, or stochastic), and thus would be expected to affect the grid differently, displacing peak or non-peak resources. For the purposes of this research, it was important to evaluate a diverse array of programs, rather than strictly realistic programs.

The incremental EE/RE measures considered were new wind resources, new solar resources, new baseload energy efficiency programs, and a new peak-shaving energy efficiency program. These incremental measures can be conceptualized with the following: (1) a new wind resource as one additional wind farm, (2) a new solar resource as one additional solar farm, (3) a new baseload energy efficiency initiative as refrigeration or industrial lighting efficiency programs, and (4) a new peak-targeting efficiency savings as demand response or efficient air-conditioning programs.[12] These four measures were chosen for a variety of reasons. Each of the measures

[11] 2009 data from EIA Form 923, annual generation by plant, aggregated by state and fuel type.

[12] A program such as a "Cool Environments Program," designed to reduce cooling requirements by reflecting solar heat and providing shade, would meet the peak-targeting program criteria.

have fundamentally different load shapes, and therefore affect the WECC system in varying ways; further, these four measures are an efficient way to represent a wide variety of programs that could theoretically and practically be chosen to reduce emissions.

Each EE/RE measure had to be sized such that it would make a measurable impact on the system. Because the WECC system is extensive, the size of the new measures had to be sufficiently large to perturb the system enough to distinguish signal from “noise.” However, the measures could not be unrealistically large, as programs that are too large in size fundamentally change the dispatch dynamics and are therefore not representative of incremental changes to the system. The measures also needed to be plausible programs that could be implemented in California and used for SIP emissions credit. Each measure should also be comparable to the other EE/RE measures. A complete description of the sizing for each measure is detailed below.

Each of the four measures was modeled in the four California zones detailed above in the Topology Section: LADWP, SDG&E, SCE, and PG&E. These zones were chosen for modeling the measures because they are the largest utilities in California. PG&E, SCE, and SDG&E are the major utilities dispatched by the California Independent System Operator (CAISO). LADWP is not part of the CAISO system, but it is the next-largest utility in California. These zones are geographically distinct and therefore provide a comprehensive picture of how measures will affect the different geographical zones of California. Because these zones do represent the largest utilities in California, it is more likely that large-scale wind or solar resources would be built or large-scale efficiency programs would be implemented in these zones than in smaller municipalities.

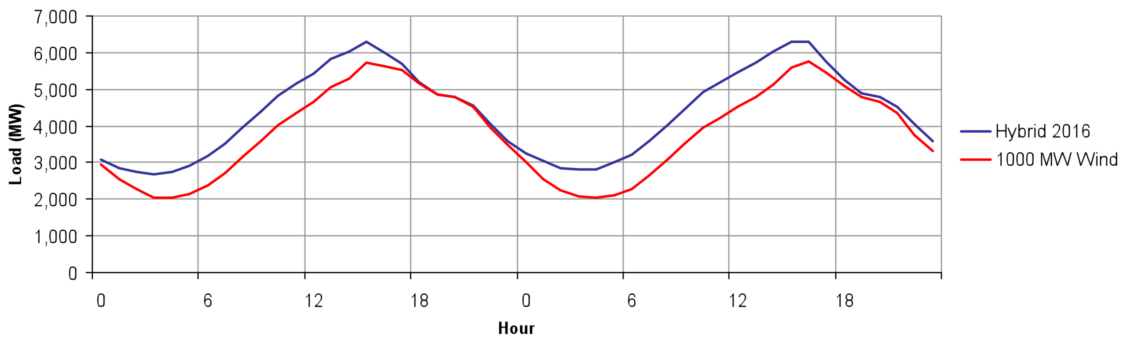
To use the dispatch model to determine displaced emissions from EE/RE, Synapse required an estimated hourly load shape for each load-reduction measure that would serve as a proxy for a specific modeled incremental energy reduction program. These load shapes are detailed below.

Wind

Synapse added 1000 MW of wind to four zones: LADWP, SDG&E, SCE, and PG&E. In SDG&E, SCE, and PG&E, Synapse was able to use hourly wind profiles from the Energy Commission’s model assumptions. The Energy Commission hourly wind profile assumptions come from the 2009 IEPR. The hourly profiles developed by the Energy Commission were scaled to reach 1000 MW. For LADWP, no Energy Commission assumption existed, so Synapse assumed that wind turbines could be built at Tehachapi and connected to the Los Angeles Basin. The hourly wind data for Tehachapi was obtained from the WECC-National Renewable Energy Laboratory (NREL) Wind Integration Study. All additional wind units ranged in capacity factor from 20 percent in PG&E (copying a pre-existing Energy Commission unit) to 40 percent in Southern California.

Figure 8, below, shows changes in effective load requirements in LADWP after the implementation of a large-scale solar PV project directly connected to the service territory. The blue line represents the hourly load shape of the node as represented in the model, while the red line indicates the reduced load equivalent from the simulated wind farm. While the wind turbine simulation does have significant hour-to-hour stochastic elements, it is seen in these example hours that the load is reduced primarily off-peak and in the morning hours. These hours are not necessarily representative of reductions from wind throughout the year.

Figure 8: Example Load Profile and Reduction from Wind in LADWP: July 11–12, 2016



A representative picture of how the new wind measures operate during the year are shown in the following figures. Figure 9 shows the average annual capacity of the wind resource at each hour. Figure 10 shows the average monthly capacity of the wind resource in each location.

Figure 9: Average Hourly Wind Capacity by Hour for 1000 MW Wind Farms in Four Service Territories

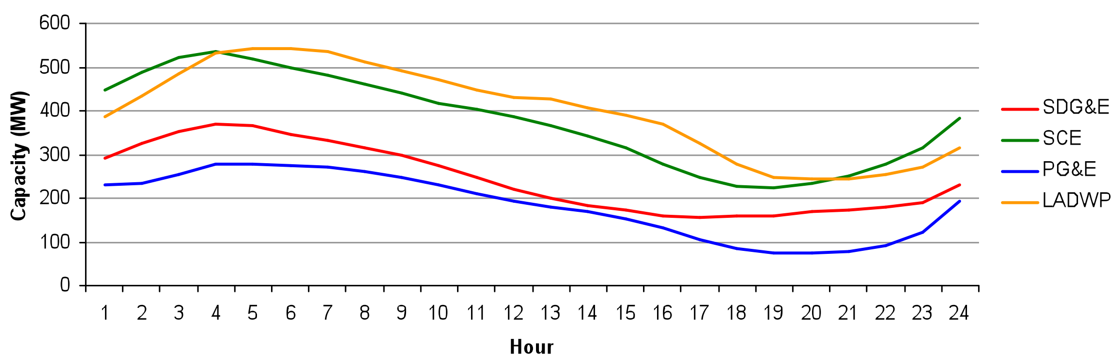
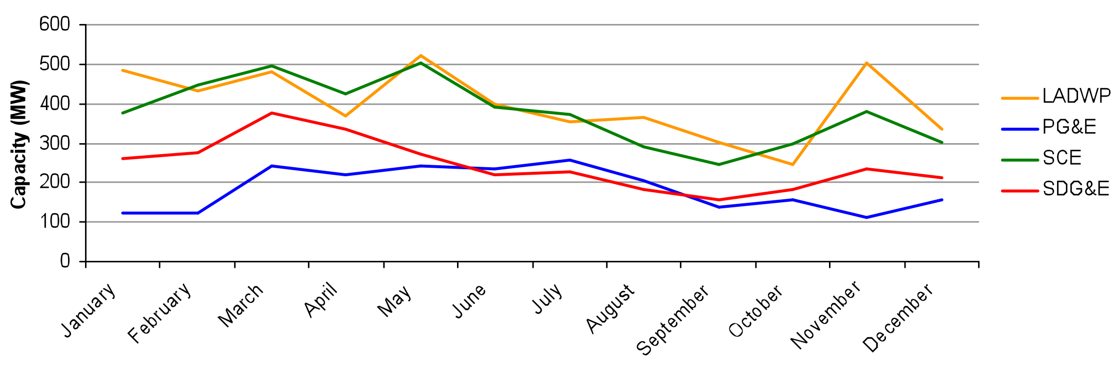


Figure 10: Average Monthly Wind Capacity by Hour for 1000 MW Wind Farms in Four Service Territories

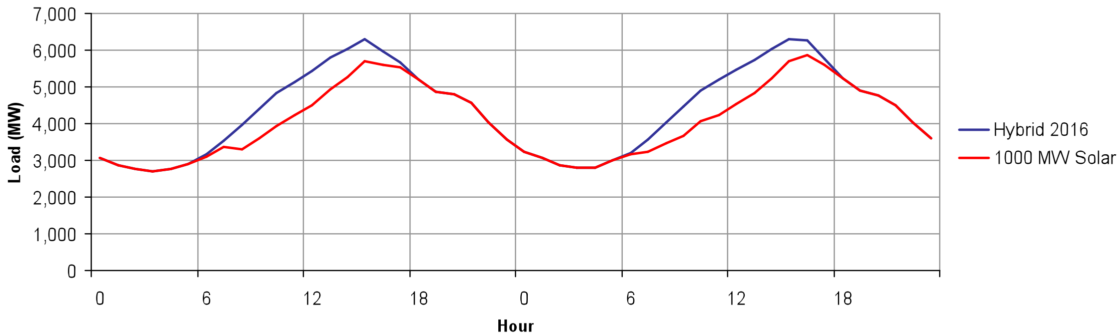


Solar

To maintain an approximate level of energy output consistency with the wind scenarios, each of the new solar units were given a rated capacity of 1000 MW and were added to the same utility service zones as the wind turbines. All solar units are assumed to be utility-scale photovoltaic units as modeled by the Energy Commission. Hourly profiles for solar units all existed in the Energy Commission dataset as assumptions from the 2009 IEPR, and these profiles were used and scaled to 1000 MW.

Figure 11, below, shows changes in effective load requirements in LADWP after the implementation of a large-scale solar PV project directly connected to the service territory.

Figure 11: Example Load Profile and Reduction from Solar in LADWP: July 11–12, 2016



The following figures represent how the new solar measures operate during the year. Figure 12 shows the average annual capacity of the solar PV resource at each hour, while Figure 13 shows average monthly capacity.

Figure 12: Average Hourly Solar PV Capacity for 1000 MW of Solar Installations in Four Service Territories

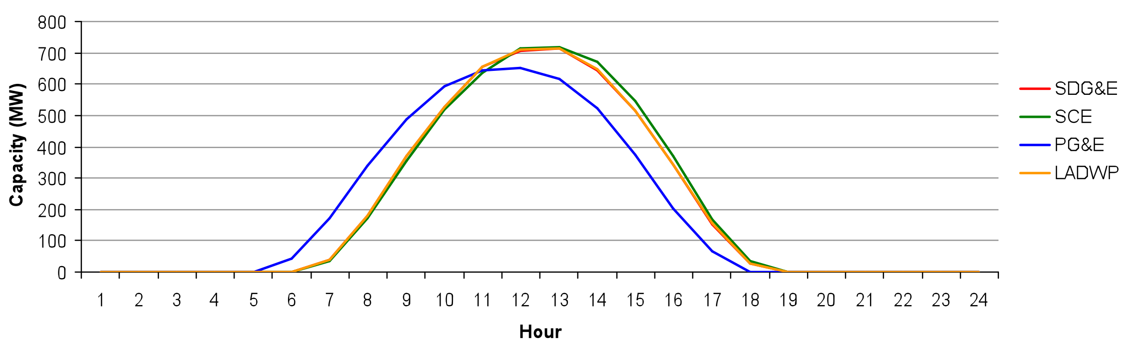
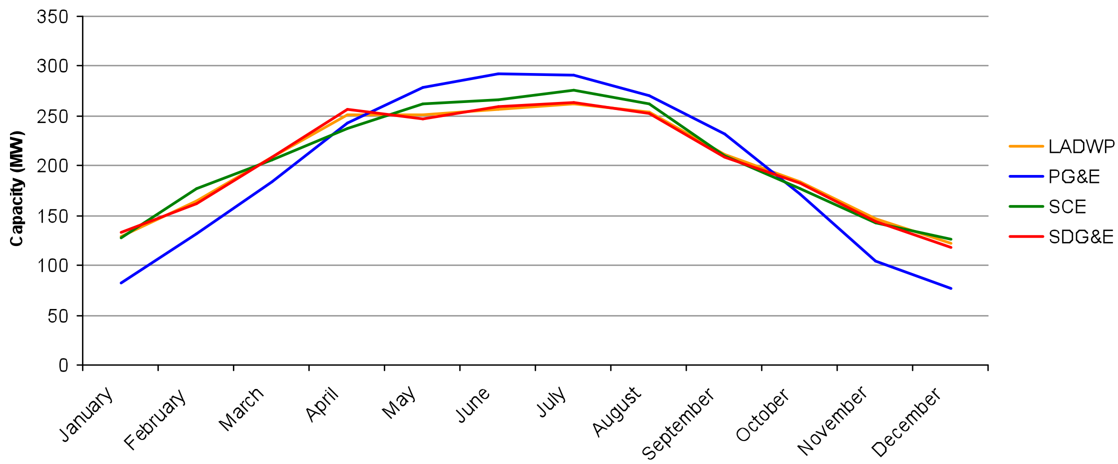


Figure 13: Average Monthly Solar PV Capacity for 1000 MW of Solar Installation in Four Service Territories



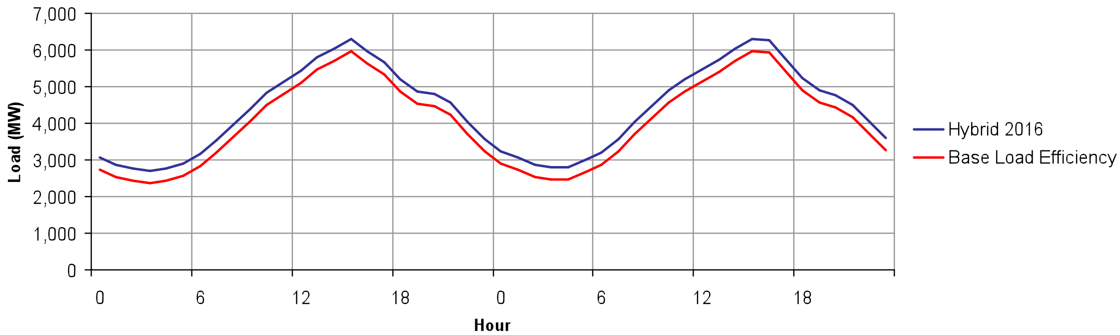
Baseload Energy Efficiency

Synapse created scenarios that modeled both baseload energy efficiency and peak-targeting energy efficiency. The energy efficiency scenarios are not meant to represent one particular, targeted program, but to examine the overall effect of cutting baseload demand or peak demand. However, the baseload efficiency characterizes the expected effect of refrigerator or industrial lighting efficiency programs, while the peak-shaving efficiency corresponds to demand response or air conditioning efficiency programs. Energy efficiency is modeled in PROSYM as a power unit, with all the characteristics of a thermal power plant.

To depict a "pure" baseload efficiency program, the baseload efficiency units are given a capacity factor of 100 percent, meaning that they are always running in the model. Because of the capacity factor, and in order to ensure comparability of energy generated in the wind and solar scenarios, all baseload efficiency units were assigned a maximum capacity value of 333 MW. A baseload efficiency unit was placed in and modeled in each of the four zones: LADWP, SDG&E, SCE, and PG&E.

Figure 14, below, shows the impact that 333 MW of baseload efficiency makes on the load in the LADWP service territory. The blue line shows the hourly load shape of LADWP as represented in the model, while the red line indicates the reduced load from the simulated baseload efficiency program. Because the baseload efficiency is set to be continuously running in the model, load in LADWP is reduced by the full 333 MW in all hours, with no hourly variation.

Figure 14: Example Load Profile and Reduction from a Baseload EE Program in LADWP: July 11–12, 2016



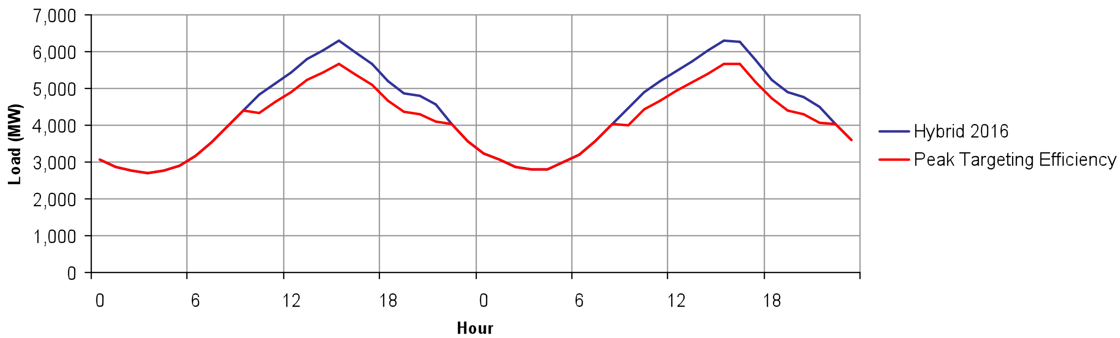
Peak-Targeting Energy Efficiency

Peak-targeting energy efficiency was designed to decrease load only on days with very high demand. This was modeled by creating a thermal unit in the model with an hourly profile, much like a solar PV or wind unit. Synapse examined the hourly load from the Hybrid Case for each in order to create an hourly profile for peak-targeting efficiency. The profile was generated by first finding which hours the load was in the 90th percentile or above, and then by shaving 10 percent off of those hours.

- In the LADWP zone in PROSYM, the maximum of the load is 6,499 MW, and the top 10 percent of hours are those where load exceeds 4,418 MW. The maximum decrease of load from a peak-targeting efficiency program in LADWP is 650 MW when the load reaches its absolute maximum.
- In SDG&E, the maximum load is 4,703 MW, and the top 10 percent of hours are those where load exceeds 3,300 MW. When load reaches an absolute peak, the maximum decrease from the peak-targeting efficiency program is 470 MW.
- In the SCE zone of PROSYM, the maximum of the load is 24,474 MW, and the top 10 percent of hours are those where load exceeds 15,912 MW. The maximum decrease of load from a peak-targeting efficiency program in SCE is 2,447 when the load reaches its absolute maximum.
- In PG&E's zone, the maximum load reaches 25,306 MW, and the top 10 percent of hours are those where load exceeds 16,711. In the hour that PG&E hits its maximum load, the peak-targeting efficient program shaves off 2,530 MW.

Figure 15 shows the impact that a peak-targeting efficiency program that shaves 10 percent of load off the top 10 percent of hours has on the load in the LADWP service territory. The blue line shows the hourly load shape of LADWP as represented in the model, while the red line indicates the reduced load from the simulated peak-targeting efficiency program. The two days represented in the figure are in July, when load approaches the peak, so the decrease in load is approaching the maximum of 650 MW. The top 10 percent of hours occur during daytime peak hours between late morning and late evening. These hours are not necessarily representative of the reductions seen from peak-targeting programs throughout the year due to the distribution of peak hours.

Figure 15: Example Load Profile and Reduction from a Peak-Targeting EE Program in LADWP: July 11–12, 2016



The following figures represent how the peak-targeting EE measures operate during the year. Figure 16 shows the average annual capacity of the EE resource at each hour, while Figure 17 shows average monthly capacity. It should be noted that the peak EE programs were created to target 10 percent of the service area load, as to not be unreasonably large. Therefore these programs appear to have very different capacities, depending on their implementation location.

Figure 16: Average Hourly Peak EE Reduction Model for Four Service Territories

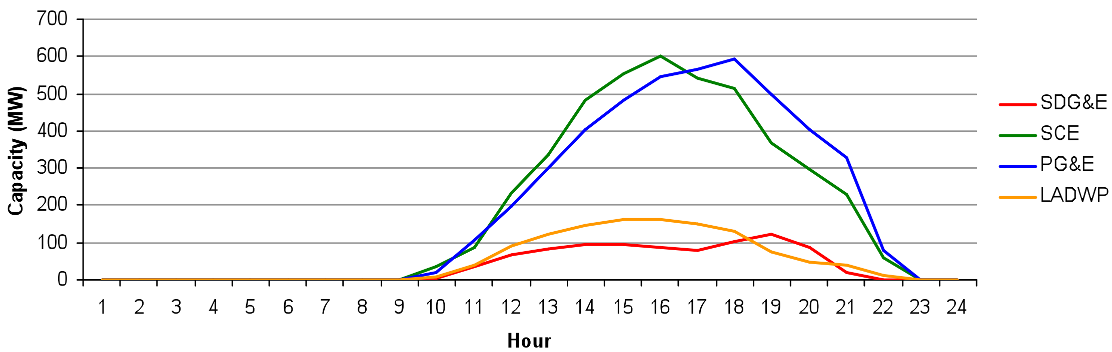
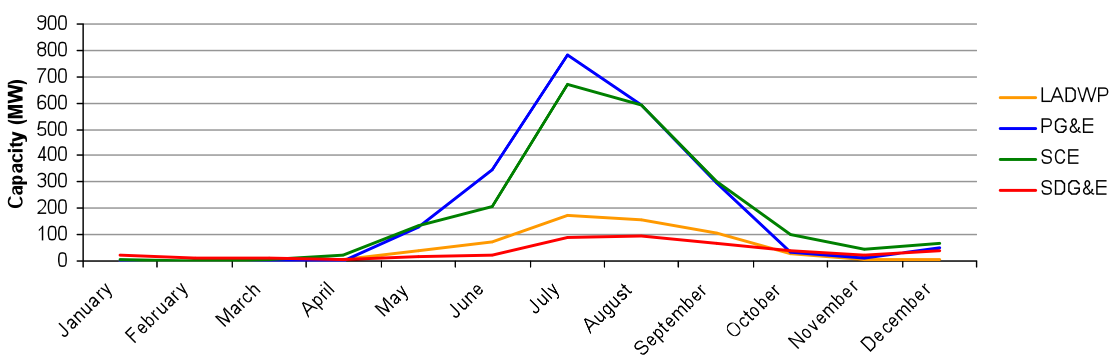


Figure 17: Average Monthly Peak EE Reduction Model for Four Service Territories



CHAPTER 3: Analysis Framework

Overview

The purpose of this analysis is to determine the emissions benefit from specific types of renewable energy (RE) and energy efficiency (EE) implemented within California (collectively, EE/RE). Ultimately, because this research is designed to estimate how emissions could be displaced in a forward-going fashion, the scale, type, or location of programs which could be implemented was unknown. Therefore, this analysis was designed to estimate the rate of displaced emissions, measured as the physical units of pollution displaced for each unit of alternative energy implemented.

This "displaced emissions rate" is designed to be scalable, within reasonable bounds, such that various amounts of EE/RE will accomplish estimated pollution reductions as a simple function of the rate and the amount of EE/RE implemented, within a particular implementation region.

In this California-based study, the displaced emissions rate is broken into its component parts, by both geography and emissions source (fuel type). In the Western Interconnect (the WECC region), the electric sector is largely divided along geographical lines, with hydroelectric resources in the Northwest, coal in the Intermountain West and Southwest, and natural gas in California. Even in the absence of additional information, reason suggests that EE/RE in California will have highly diversified impacts throughout the West in both generation and emissions. It is therefore critical that the displaced emissions rate for California be parsed by, at the very least, the geography of displaced energy resources.

A California-wide displaced emissions rate is not useful for the purposes of determining emissions benefits within specific air districts. Transmission constraints, unique long-distance interconnections, and the variance in energy resources across California render the impact of any given EE/RE initiative very different in each air district. Therefore, within the state, the displaced emissions rate is parsed into the air districts in which the emissions reduction benefit occurs.

At a fine-grained level of resolution, particularly for air districts with little generation, there is significant uncertainty from the model results as to what amount of displaced energy and emissions are due to EE/RE, and what can be attributed to random error or uncertainty within the model construct itself. It is important for this analysis to explicitly estimate model uncertainty.

The following sections describe, in a stepwise fashion, how this research examines:

- displaced energy (generation) in general,
- displaced emissions on a regional and air district basis, and
- random error and uncertainty.

Displaced Energy

Displaced energy is defined as the energy which is not served by marginal generators (either reduced or curtailed) when new renewable energy produces electricity or efficiency is available. Given a balance between load (demand) and generation, a generating unit (or, more likely, a cohort of generators) will be displaced by new "must take" energy or load reductions from

EE/RE. The amount of energy displaced should be approximately equal to the amount of energy in the EE/RE, plus or minus transmission losses if these occur in different locations.

In this research, the "displaced energy fraction" (gf_{disp}) is calculated as:

$$gf_{disp} = \frac{\sum g_{baseline,i,t} - \sum g_{scenario,i,t}}{\sum g_{EE/RE,t}}$$

where $g_{baseline}$ represents the baseline energy from a set of generators i over time period t, $g_{scenario}$ is the energy from the same generators in the scenario of interest, and $g_{EE/RE}$ is the energy from the EE/RE in the same time period t. The subset of generators i can refer to either all generators in the model region, in which case the displaced emissions rate represents a total sum rate, or a subset of generators in a particular region or air district or of a fuel type (or both). Over the entire WECC region, this analysis examined displaced energy at both the full WECC regional-scale and within California at the air district scale.

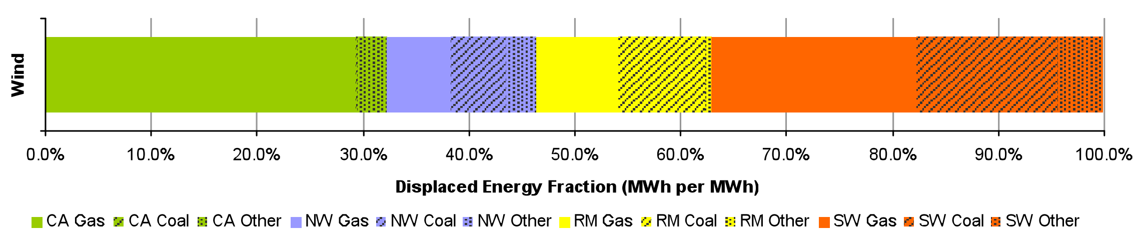
In this research, all displaced energy and emissions are given relative to the amount of added energy in the EE/RE:

- **displaced energy** is the amount of energy (MWh) curtailed per unit of added EE/RE energy (MWh), and
- **displaced emissions** are physical units of pollution (tons or lbs.) reduced per unit of added EE/RE energy (MWh or GWh).

In the displaced energy analysis, the total sum displaced energy should be approximately 100 percent, but the location and fuel types of the displaced resources are also of significant interest; these fractions will add up to 100 percent.

An example of a displaced energy analysis for WECC regions is given in Figure 18, below.

Figure 18: Example of Displaced Energy Fraction by WECC Region and Fuel Type: MWh of Generation Displaced per MWh of New Wind in SCE



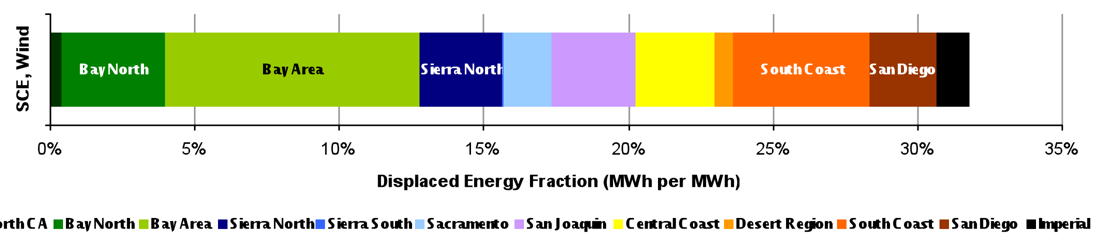
The bar represents the fraction of energy displaced, which cumulatively should add up to approximately 100 percent. The colors of the bar represent the areas where EE/RE displacement occurs: green in CA (32 percent), blue in the NW (14 percent), yellow in the RM (17 percent), and the remainder in the SW (37 percent); similarly, the patterns on the bar colors represent the major classes of fuel type displaced by the EE/RE, with solid colors representing natural gas (overall, 63 percent), stripes representing coal (27 percent), and dots "other" (primarily comprised of oil, petroleum products, and biomass, including refuse and wood) (10 percent).

In the example shown, the scenario is identified as an EE/RE program of new wind in the SCE service territory. All of the energy added into the system (in this case, approximately 2600 GWh from the equivalent of a 1000 MW wind farm) is displaced throughout the WECC region; it is displaced only partially in California, while the rest is displaced throughout WECC.

The implications for this wide distribution of displaced energy from EE/RE in California is that only about one-third of the displaced energy has an emissions benefit in California, while the remainder is spread throughout other regions of the West. The displaced fuel within California is natural gas over 90 percent of the time.

The component of generation which is displaced within California can be further parsed by air district. Figure 19, below examines the net 32 percent of generation displaced within the state, parsed by air district region (see WECC and Air District Region Definitions on page 17 for air district regions). In this case, the largest single beneficiary of new wind in SCE territory are generators in the Bay Area, at about 9 percent of total generation, or about 30percent of generation within California.

Figure 19: Example of Displaced Energy Fraction within California, by Air District Region: MWh of Generation Displaced in California per MWh of New Wind in SCE



This analysis shows a small *negative* displaced energy in the Central Coast region (i.e., an apparent *increase* in generation relative to the base case. These increases, though small, represent significant potential random errors within the analysis, which are explored at the end of this chapter.

Displaced Emissions

Displaced emissions are emissions which are avoided when EE/RE cause a reduction or curtailment in generation from fossil-fired generators. Of particular interest to this research are NO_X, SO_2, and CO_2 from coal, natural gas, petroleum, and other hydrocarbons, as well as biomass and waste sources. The PROSYM dispatch model tracks these criteria and greenhouse gas emissions; emissions results were output at a monthly time step. For the purposes of this analysis, hourly output was not pursued for all WECC generators.

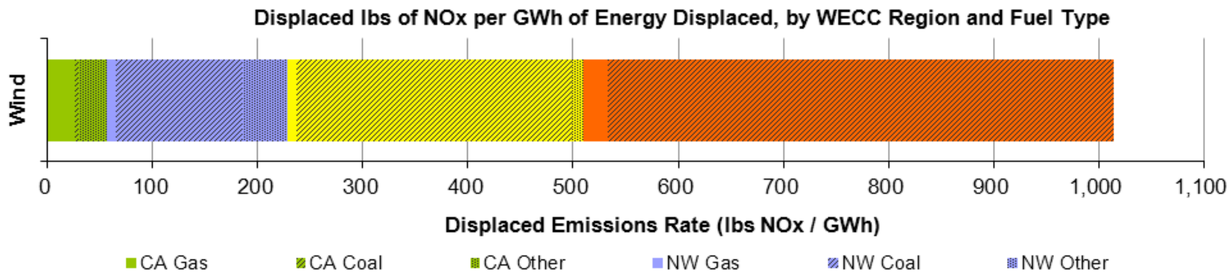
For this research, displaced emissions are estimated as a *rate*, in physical units of pollutant avoided per each unit of EE/RE energy (lbs/MWh). This rate allows the user to scale avoided emissions to the amount of RE or EE in the EE/RE. As with the energy analysis, the displaced emissions rate can be parsed by geography (region or air district) and fuel type.

The displaced emissions rate (er_{disp}) is calculated as:

$$er_{disp} = \frac{\sum e_{baseline,i,t} - \sum e_{scenario,i,t}}{\sum g_{EE/RE,t}}$$

where $e_{baseline}$ represents the baseline emissions (in lbs of NO_X or SO_2, or tons of CO_2) from a set of generators i over time period t, $e_{scenario}$ are the emissions from the same generators in the scenario of interest, and $g_{EE/RE}$ is the generation (in GWh) from the EE/RE in the same time period t. This equation yields the physical units of pollution displaced for each unit of energy produced by EE/RE, or the estimated displaced emissions rate. The sum of all regional displaced emissions rates is equal to the total sum rate, as shown in the example in Figure 20, below:

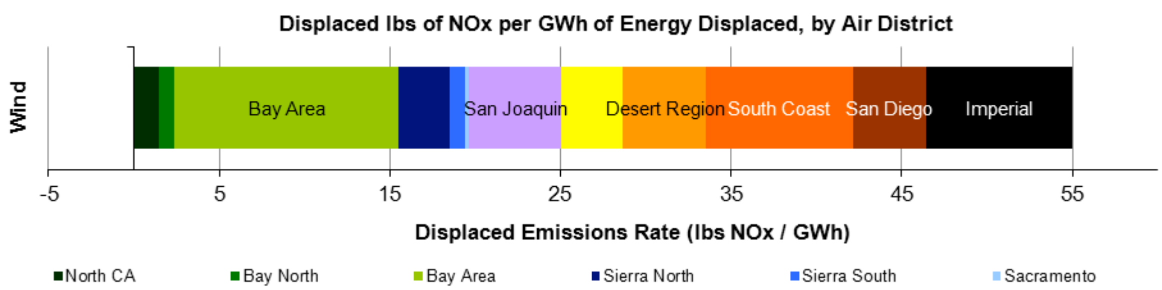
Figure 20: Example of Displaced Emissions Rate by WECC Region and Fuel Type: SCE Wind



Similar to the displaced energy fraction in Figure 19, the bar in Figure 20 shows the regional displaced emissions rate, parsed by the major WECC regions and fuel types. In this case, the net aggregate displaced emissions rate is approximately 1010 lbs NO_X displaced for each GWh[13] of new wind generation in the SCE service territory. However, a vast majority (85 percent) of the aggregate rate is a function displacing out-of-state coal power; the benefit realized within California is about 60 lbs NO_X per GWh of new wind. This low rate is a combined function of both a fairly small fraction of energy displaced within California (32 percent) and the very low emissions rate of generators within the state.

Like generation, the displaced emissions rate can be parsed to air districts within California. However, it should be noted that as the displaced emissions rate is parsed further, the accuracy of the solution decreases markedly due to random events intrinsic to both the model and reality. Figure 21, below, shows the displaced emissions of NO_X subdivided among air district regions.[14]

Figure 21: Example of California Component of Displaced NO_X Emissions Rate, by Air District Region: SCE Wind



The figure shows that the displaced NO_X emissions from a new wind project in the SCE service territory are distributed over numerous air districts. The highest displaced emissions rate is seen in the Bay Area, at about 13 lbs NO_X/GWh.

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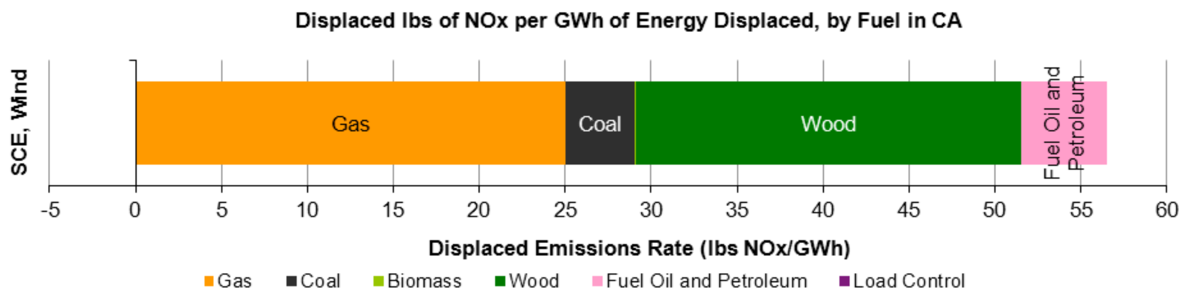
[13] Emissions in the power sector are often given in lbs/MWh of output. However, due to the fairly small values in this analysis, the output for criteria emissions are given here in lbs/GWh, where one gigawatt-hour (GWh) is equal to 1000 megawatt-hours (MWh). Emissions of CO_2 are given in tCO_2/MWh.

[14] It should be noted that these displaced emissions represent annual emissions from generators which reside within the air district regions, and do not represent expected changes in ambient air quality or population exposure to those emissions.

Finally, it is illustrative to examine the displaced emissions rate in California by fuel type, such as shown in Figure 22, below.

Figure 22: Example of California Component of Displaced NO_X Emissions Rate, by Fuel Type within California: SCE Wind



The figure illustrates that while natural gas accounts for a vast majority of the displaced energy in California (over 90 percent, see Figure 18, above) it is a smaller fraction of the displaced emissions rate within California (~40 percent), at least for this example EE/RE (wind in SCE). This small reduction is because natural gas in California has, by a large fraction, the lowest NO_X emissions rate. Wood, which is only about 3 percent of the displaced energy within California, accounts for another 40 percent of the displaced emissions rate. Generally speaking, the reason for this is that displaceable wood generation in California has a far higher emissions rate than natural gas (about 2.4 lbs NO_X /MWh [240 lbs/GWh] for wood, versus < 0.4 lbs NO_X/MWh [40 lbs/GWh] for natural gas), and therefore makes up a larger fraction of the emissions margin.

The very large component of California displaced emissions that appear to come from wood-fired generation raises the question of whether these emissions benefits are "real" or not—that is, if they are more readily explained by random error or by actual displaced energy. The following section describes our error analysis for this research.

Uncertainty and Error Analysis

The displaced emissions calculated in this analysis must be contextualized within the framework of the model, and specifically, the errors and uncertainties associated with both the model and real dispatch operations. The model used here is a commercial-scale utility dispatch model (see earlier Modeling Framework section), but nonetheless has significant limitations, particularly as applied to a displaced energy analysis. In particular, the model used here is highly simplified in order to solve a complex problem in reasonable time. To some extent, the errors and uncertainty described here and applied to this analysis are a function of the model, but to a larger degree, may represent a wide uncertainty experienced in a complex and dynamic electric system.

One can characterize aspects of systematic or architectural errors, as well as uncertainties which are purpose-built into the model itself.

Structural Uncertainty and Systematic Error

Systematic and architectural errors are defined as fundamental aspects of the electricity market which this model cannot capture, as well as simplified assumptions used to streamline model use, runtime, and results. These uncertainties are, in large parts, fertile ground for future research efforts, and as such are described in the discussion section later. Among these uncertainties are model topology (including both temporal and spatial resolution), future fuel and emissions costs, new generation and retirement, expected emissions controls in place in the analysis year, and stochastic behaviors for wind and the EE/RE load profiles chosen for this analysis.

Random Error – Forced Outage Noise

Random errors are defined as inconsistent measurements over repeated observations. The model utilized for this research does have a random component which describes forced outages, or times when specific units are unavailable due to unpredictable maintenance requirements. These forced outages occur randomly with a given probability for many electricity generating units (EGU); the random element is that in any given run or scenario, a unit may spend a fraction of its time offline. In the model, forced outages occur randomly with a given frequency.

When an EGU is forced offline, other EGU ramp up to meet load requirements; these adjustments in the loading change both generation patterns and emissions. As an extreme example, if one of the large nuclear units has a forced outage, its equivalent energy will be served by additional natural gas and coal units across WECC, apparently “adding” emissions to the system.

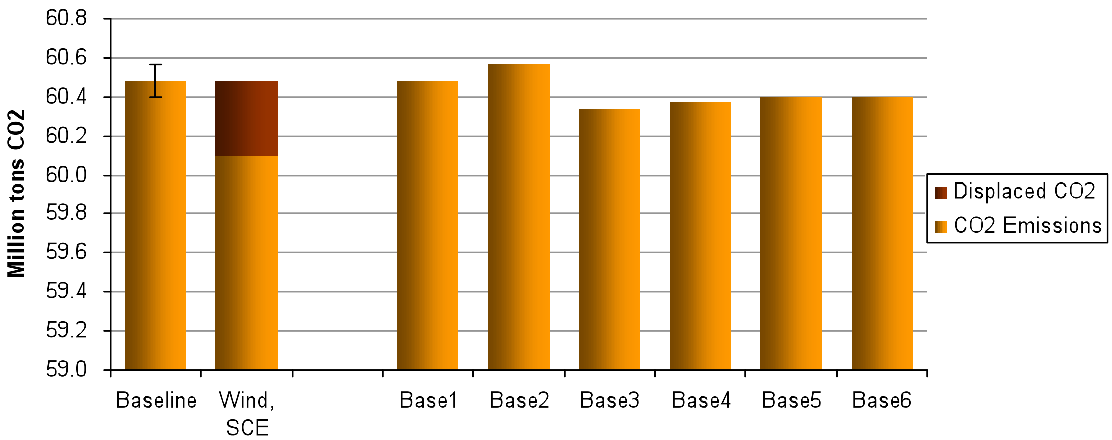
In any given model run (scenario), it is not possible to predict which changes in generation and emissions are due exclusively to the modeled EE/RE and which are due to random forced outages—all occur simultaneously. Without numerous (and highly time-intensive) runs of each scenario to estimate an average behavior, the expected value behavior of the displacement due to EE/RE alone (versus outages) cannot be explicitly determined. Therefore, an analysis mechanism is required to account for forced outage uncertainty, termed “noise” in the system.

To account for this uncertainty, the base case was run six times; from these six iterations, it was possible to estimate changes in generation due only to forced outages. In each region, transmission area, and air district, Synapse estimated the standard deviation of the generation and emissions within each fuel group. When the noise due to forced outages (the standard deviation) exceeds the change in generation or emissions between the scenario and base case, an individual estimate of displaced energy or emissions is termed “non-meaningful.”[15]

Figure 23, below, illustrates an example of how the error is evaluated in this model. This case examines the total CO_2 emissions from generators in California. In the baseline run, slightly more than 60.4 million tons of CO_2 are emitted from California generators. In the SCE Wind scenario, the EE/RE displaces approximately 380,000 tons of CO_2 in 2016 (represented by the dark red bar).

[15] Both the base case and each scenario have a random draw component in choosing the timing of forced outages. If any given difference between a scenario and the base case is due to a forced outage only, then the difference is not valuable from a displaced emissions standpoint, and is therefore “not meaningful”.

Figure 23: CO_2 Emissions, Displaced Emissions, and Iteration Run Emissions in California, All Fuel Types. ***Note, the y-axis does not begin at zero.***



To estimate if the displaced emissions are significant, or likely due only to random forced outages in this particular run, Synapse calculated the standard deviation of all CO_2 emissions in California in the iterations of the baseline runs (the six separated bars). The standard deviation, denoted in Figure 23 as an error bar on the baseline, is approximately 80,000 tons of CO_2. Synapse estimates that the actual displaced CO_2 emissions from this EE/RE cannot be predicted within an error of 80,000 tons (or 22 percent of the displaced emissions). The total displaced energy for this particular EE/RE is 2923 GWh per year; therefore, the estimated displaced emissions rate is approximately 0.13 tCO_2/MWh (380/2923 = 0.13), but the error in that rate is 0.03 tCO_2/MWh (80/2923 = 0.03).

In numerous scenarios and particular areas, the error (noise) exceeds the displaced emissions or generation (the signal). In these cases, there is lower confidence of the displaced emissions generation or emissions rate. This circumstance occurs under circumstances and regions where the displacement is relatively small and the forced outage rate is relatively high.

Formally, the uncertainty in generation and emissions are estimated as the standard deviation of the six baseline runs, as in the following equations:

$$g_{std,i,t} = std\left(\sum g_{baseline,i,t,a}\right)$$

and

$$e_{std,i,t} = std\left(\sum e_{baseline,i,t,a}\right)$$

where g_{std} and e_{std} are the standard deviation of generation (in GWh) and emissions (in tons or lbs) over cohort of generators i in time period t, and $g_{baseline}$ and $e_{baseline}$ are the six baseline runs a (one through six) over the same cohort of generators in the same time period.

The error rate in generation (gf_{std}) and the emissions rate (er_{std}) are estimated similarly to the fraction of generation displaced by the EE/RE and the displaced emissions rate due to the EE/RE, as:

$$gf_{std,i,t} = g_{std,i,t} \Big/ \sum g_{EE/RE,t}$$

and

$$er_{std,i,t} = e_{std,i,t} \Big/ \sum g_{EE/RE,t}$$

In the following results section, the displaced generation fraction and displaced emissions rates are followed by the error rate, in the same units. This value can be interpreted as a plus-or-minus value.

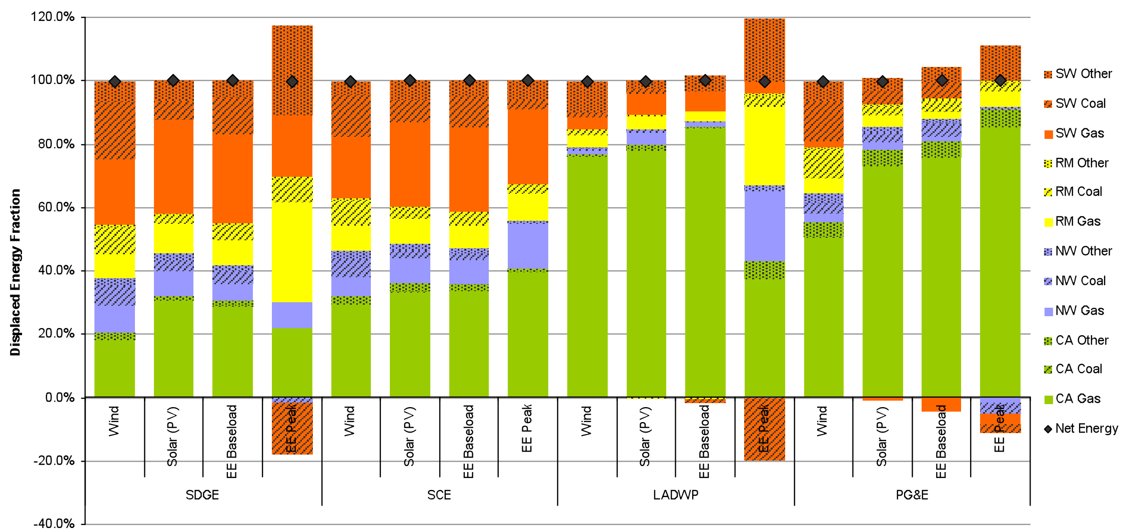
CHAPTER 4: Results

The following results section is comprised primarily of tables and graphs with the estimated displaced energy fraction and displaced emissions rates. Results are presented for generation, NO_X, SO_2, and CO_2, shown regionally and then by air district. All detailed results are given in both **Appendix C** and the attached **Data Annex**.

Displaced Energy Fraction, by Region and Fuel Type

The displaced energy fraction for all sixteen EE/RE scenarios, parsed by WECC region and fuel type is shown in Figure 24, below.

Figure 24: Displaced Energy Fraction (MWh Displaced Energy per MWh of EE/RE) by WECC Region and Fuel Type



The first four bars represent the displaced energy fraction of EE/RE implemented in the San Diego Gas & Electric (SDG&E) service territory, followed by EE/RE implemented in Southern California Edison (SCE), the Los Angeles Department of Water and Power (LADWP), and Pacific Gas and Electric (PG&E). Each of the four EE/RE are ordered by onshore wind, utility-scale solar PV, a baseload EE load shape, and a peak-reducing EE program.

The color scheme and fuel type demarcation are identical to those presented in example Figure 18, above; green bars (of all textures) represent the fraction of the EE/RE that is displaced in California, blue in the Northwest, yellow in the Rocky Mountains (Intermountain West), and orange in the Southwest. Solid bars represent the fraction displaced by natural gas, stripes represent coal displacement, and dots are "other" forms of displaceable generation.

The chart is a useful illustration of how particular types of programs affect generation throughout WECC. In SDG&E and SCE, most programs appear to displace primarily outside of California, only affecting California generation 20 to 40 percent of the time, while in LADWP and PG&E, EE/RE tend to displace primarily within California (and, as will be seen later, primarily in their own service territories). Displaced energy outside of California is a mix of coal and natural gas, with some "other" (primarily petroleum and oil outside of California), while displaced generation in California is largely natural gas, with very small fractions of "other" (primarily load control mechanisms—see section below on displaced fuel types).

A striking attribute of the chart is the negative displaced energy value in three of the EE peak reduction programs, and even in some of the EE baseload programs; these negative values of displaced energy represent increases in coal generation in the Southwest relative to the baseline when these types of EE programs are implemented. The model indicates that SDG&E peak reduction program, for example, increases coal generation in the Southwest by approximately 16 percent of the magnitude of the EE/RE;[16] however, the uncertainty on this value is 24 percent, meaning that the noise far exceeds the signal in this example.

A more subtle pattern which emerges from this analysis is that off-peak wind programs displace more out-of-state (coal) generation than on-peak solar EE/RE; this pattern might be expected, as off-peak programs may be able to cut into baseload generation more effectively than peak-targeting programs.

Aggregates of the data in the chart above are represented in Table 3 and 4, below (with eight scenarios in each table).

Table 3: Displaced Energy Fraction by WECC Region for Eight EE/RE Scenarios. The top value is the displaced energy fraction, and the lower value is the uncertainty range. If the signal exceeds the noise, the value is bold. (1 of 2)

Displaced Energy Fraction (%)	SDGE, Wind	SDGE, Solar (PV)	SDGE, EE Baseload	SDGE, EE Peak	SCE, Wind	SCE, Solar (PV)	SCE, EE Baseload	SCE, EE Peak
CA	**20.6%**	**32.3%**	**30.6%**	22.0%	**32.3%**	**36.3%**	**35.7%**	**40.8%**
	9.5%	9.4%	5.7%	52.7%	5.7%	9.3%	5.7%	10.6%
NW	**17.2%**	**13.4%**	**11.1%**	6.4%	**14.0%**	**12.4%**	**11.4%**	**15.0%**
	7.2%	7.1%	4.3%	39.9%	4.3%	7.0%	4.3%	8.0%
RM	**16.9%**	**12.3%**	**13.4%**	**39.4%**	**16.7%**	**11.4%**	**11.7%**	**11.7%**
	3.9%	3.9%	2.4%	21.7%	2.4%	3.8%	2.4%	4.4%
SW	**45.2%**	**42.0%**	**44.9%**	31.8%	**36.8%**	**39.8%**	**41.1%**	**32.3%**
	9.6%	9.5%	5.8%	53.4%	5.8%	9.4%	5.8%	10.7%

[16] For a 100 GWh of energy reductions during peaking hours, coal generators in the Southwest would increase generation by 16 GWh.

Table 4: Displaced Energy Fraction by WECC Region for Eight EE/RE Scenarios. The top value is displaced energy fraction; the lower value is the uncertainty range. If the signal exceeds the noise, the value is bold. (2 of 2)

Displaced Energy Fraction (%)	LADWP, Wind	LADWP, Solar (PV)	LADWP, EE Baseload	LADWP, EE Peak	PG&E, Wind	PG&E, Solar (PV)	PG&E, EE Baseload	PG&E, EE Peak
CA	**77.0%**	**80.0%**	**85.6%**	**43.0%**	**55.5%**	**78.3%**	**80.8%**	**91.1%**
	5.9%	9.4%	5.7%	38.5%	13.2%	9.7%	5.7%	10.2%
NW	1.9%	4.8%	1.4%	23.7%	8.9%	7.0%	**7.3%**	-4.4%
	4.5%	7.1%	4.3%	29.1%	10.0%	7.4%	4.3%	7.7%
RM	**5.9%**	**4.3%**	**3.1%**	**28.9%**	**14.8%**	**7.3%**	**6.4%**	**8.2%**
	2.4%	3.9%	2.4%	15.9%	5.4%	4.0%	2.4%	4.2%
SW	**15.1%**	**10.8%**	**9.9%**	4.2%	**20.6%**	7.2%	5.5%	5.0%
	6.0%	9.5%	5.8%	38.9%	13.3%	9.8%	5.8%	10.3%

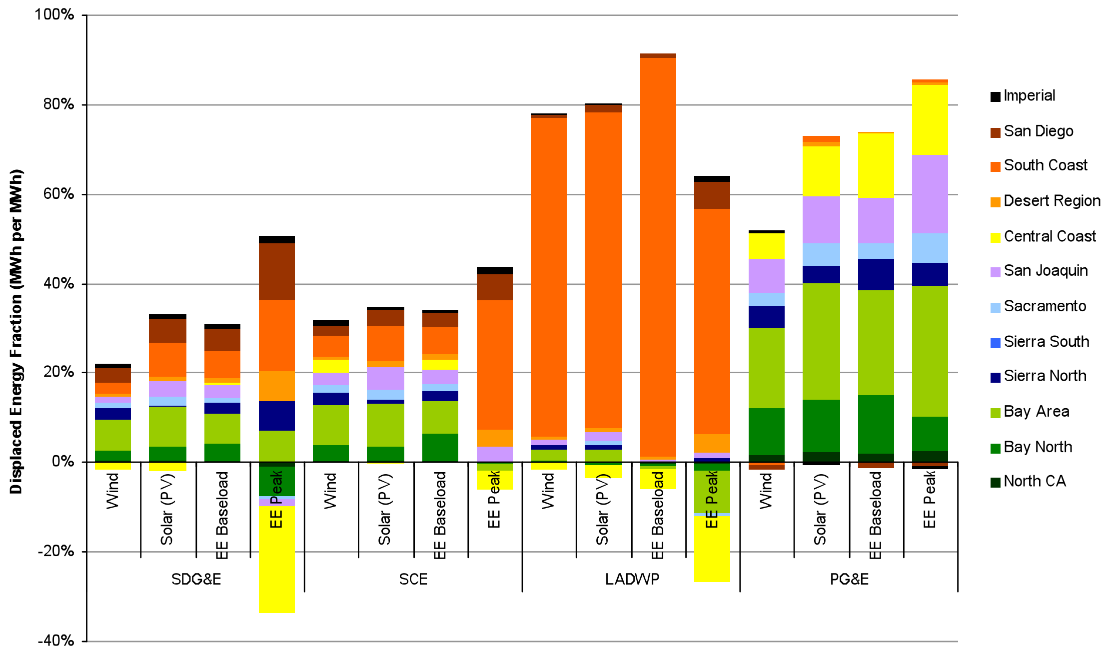
In this table (as all others following), the top value represents the displaced energy fraction (or in later charts, the displaced emissions rate) for the column EE/RE and row region. The lower value represents the uncertainty range in the *same* units as the displaced energy fraction (or emissions rate, respectively). When error values exceed the signal, both values are gray. In all cases, except the SDG&E peak reduction EE/RE, the fraction of generation displaced within California exceeds the noise (barely in LAWDP), although this fraction can vary significantly.

The large variance in many of these values indicates just how deeply interconnected the WECC region is; small changes in forced outages throughout the region can steeply vary where generation is displaced, in many cases even exceeding the amount of generation that is displaced by a large new renewable energy or efficiency program. In some regions, such as LADWP and PG&E territory (northern California), the fraction of generation displaced within California is far higher, and therefore the uncertainty component much lower.

Displaced Energy Fraction, by Air District Region

Within California, various air district regions see different levels of generation displaced by EE/RE, depending on the type and service territory in which the program is implemented (see Figure 25, below). The layout of EE/RE across the x-axis is identical in this chart, grading through wind, solar, and the two EE programs in each of the four service territories. However, instead of examining generation across all WECC regions, the displaced energy fraction is parsed within California air district regions (see definitions in Table 1). The net total of both positive and negative displaced energy equals the total displaced energy fraction in California, from Figure 24, above.

Figure 25: Displaced Energy Fraction (MWh Displaced Energy Per MWh of EE/RE) in California, Parsed by Air District Region



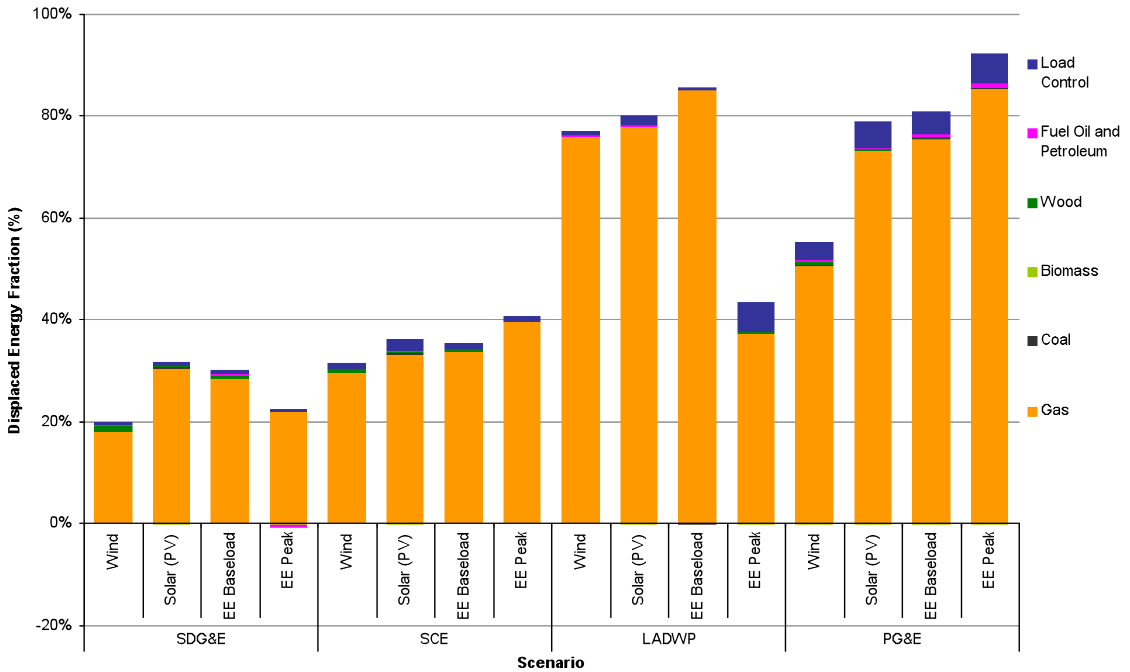
It is notable that, similarly to the WECC-wide results, EE/RE in SDG&E and SCE tend to displace generation across a much wider area than EE/RE in LADWP and PG&E. In fact, EE/RE in the two southern ISO utilities displace in nearly equal proportion in northern and southern California. In contrast, EE/RE in the LADWP service territory are highly specific to LADWP, displacing almost exclusively within the LADWP zone. Finally, EE/RE in the PG&E territory targets generators in the northern reaches of the state, with only fairly small fractions in the south.

In accordance with the WECC-wide results, peaking EE/RE appear to reduce generation in some regions, yet increase generation in others (negative displaced energy fraction). In particular, the increase in generation in the Central Coast air district region (yellow) usually exceeds the noise, suggesting that this increase in generation is real.

Tables for the displaced energy fraction by air district region are given in **Appendix C** and the **Data Annex (**an Excel workbook).

The net impact of these EE/RE scenarios on fuel types in California is shown in Figure 26, below. The figure indicates that a large fraction of the displacement in California is from natural gas generators. Note that there is almost a negligible contribution in displaced energy from wood-fired generators; a factor which will become important when reviewing displaced emissions.

Figure 26: Displaced Energy Fraction (MWh Displaced Energy per MWh EE/RE) in California, Parsed by Fuel Type



Displaced NO_X Emissions, by Region and Fuel Type

Oxides of nitrogen (NO_X) are emitted by all combustion fuels, but the native emissions rate from coal exceeds that of natural gas by an order of magnitude or more. Most combustion sources can be controlled for NO_X emissions, and these controls are largely represented in the model with lower NO_X rate inputs at controlled generators. As described in **Appendix A**, NO_X emissions rates were corrected for mischaracterized California generators, but not for generators outside of the state.

In general, generators in California are highly controlled for NO_X emissions, and the state contributes a relatively small fraction of NO_X in the Western Interconnect (< 5 percent of the NO_X in this analysis, see Figure 27). Emissions out-of-state are much higher, mostly due to uncontrolled coal generators. Therefore, it is expected that significant NO_X reductions will mostly be realized out-of-state if a program displaces non-California generation.

Figure 27: Total Modeled NO_X Emissions by Month in Each WECC Region in 2016

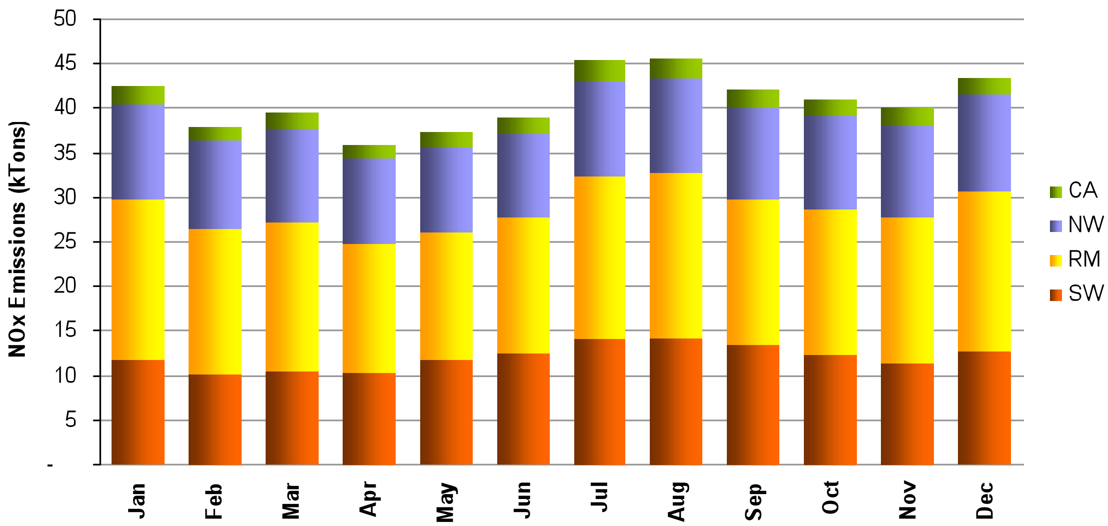
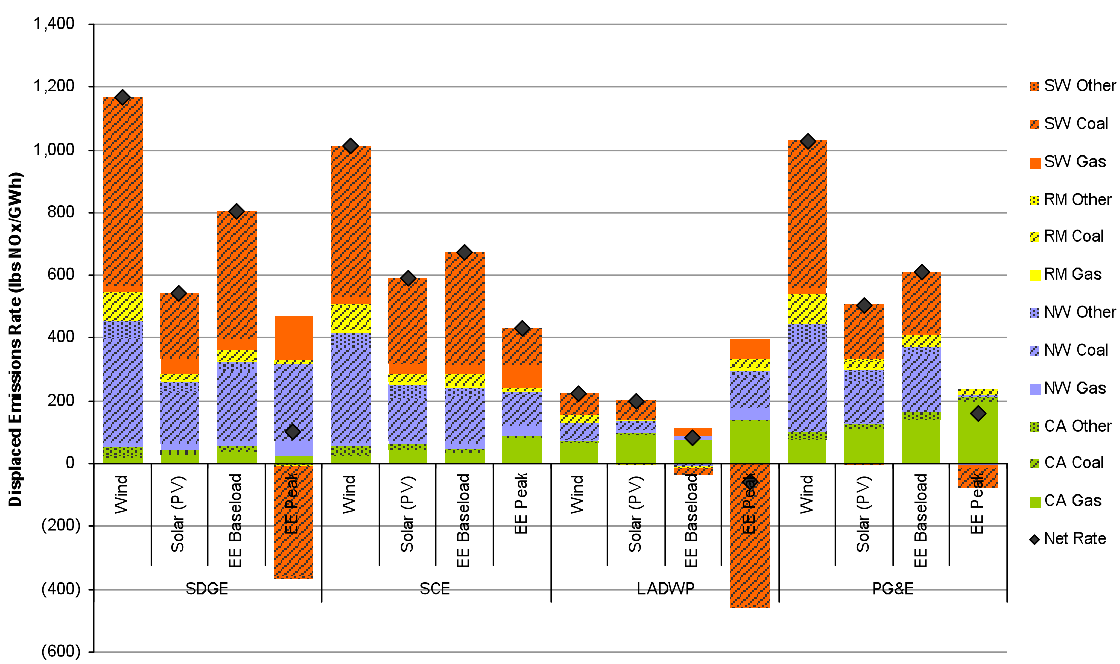


Figure 28, below shows the displaced NO_X emissions rate for all of WECC, in pounds of NO_X per *gigawatt-hour* of EE/RE generation. The rate is given in an unusual unit (on a per GWh basis) for readability only, due to the small value in California.

Figure 28: Displaced NO_X Emissions Rate (in lbs NO_X per GWh of EE/RE Generation), by WECC Region and Fuel in 2016

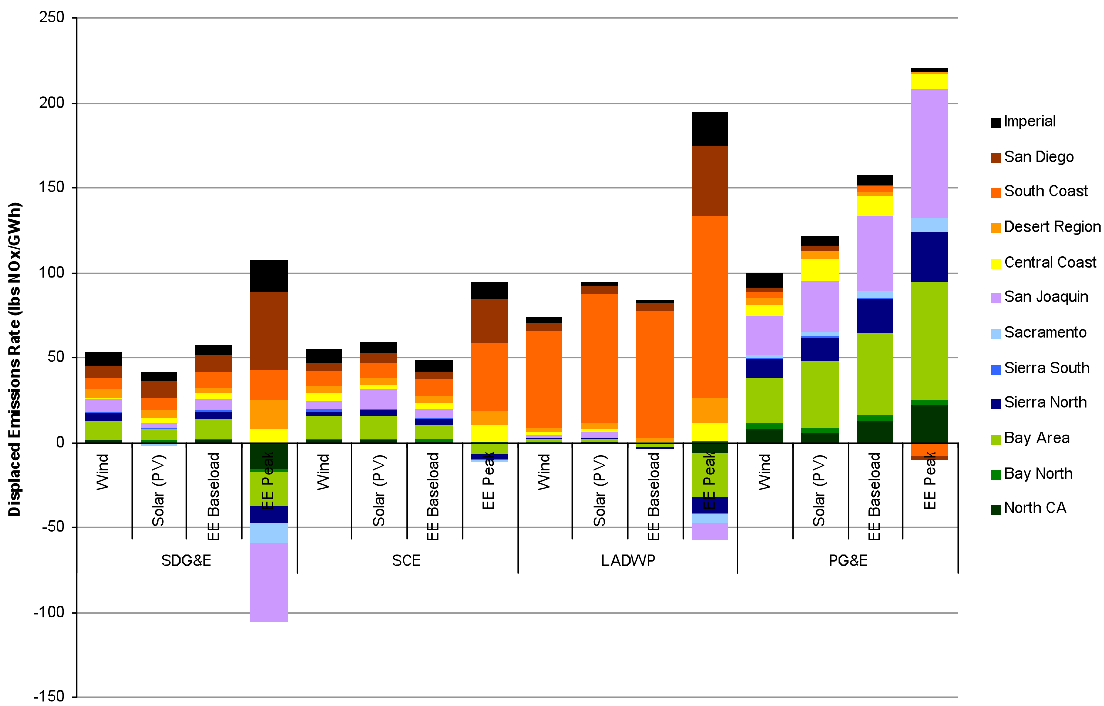


A vast majority of the NO_X reduction benefit is realized out-of state for most EE/RE. Nonetheless, the displacement is highly distributed across WECC. The net rate is negative in the LADWP peak EE EE/RE because the benefit in California and the NW is outweighed by an apparent increase in coal generation in the Southwest; a similar story is seen in both SDG&E and PG&E peaking programs.

Displaced NO_X Emissions, by Air District Region

The small component of NO_X displaced emissions rate that is realized in California air district regions is graphed in Figure 29, below.

Figure 29: Displaced NO_X Emissions Rate (in lbs NO_X/GWh) in California Air District Region



For the most part, displaced emissions rates in the southern air districts are significant for EE/RE implemented in the three southern utilities (SDG&E, SCE, and LADWP), while displaced emissions rates in the air districts in Northern California (i.e., Northern California to the Central Coast) are significant for EE/RE implemented in the PG&E service territory. The negative displaced emissions rates (i.e., increases in emissions) in the north from peaking EE/RE in SDG&E and LADWP are generally on the same order of magnitude as noise, suggesting that while real patterns may exist, they are more easily explained by random variance than by load changes from EE/RE. This pattern is explored in more depth in the Negative Displacement Patterns section of Chapter 5.

Table 5 and Table 6, below, show the NO_X displaced emissions rate by air district. Each table includes results for eight different scenarios. Again, the rate is given as the first value, and uncertainty values are given in the second value in each cell. Values where the noise exceeds the value are grayed, and negative values are given in red.

Table 5: Displaced NO_X Rate (in lbs NO_X per GWh of EE/RE) for Eight Scenarios by California Air District Region

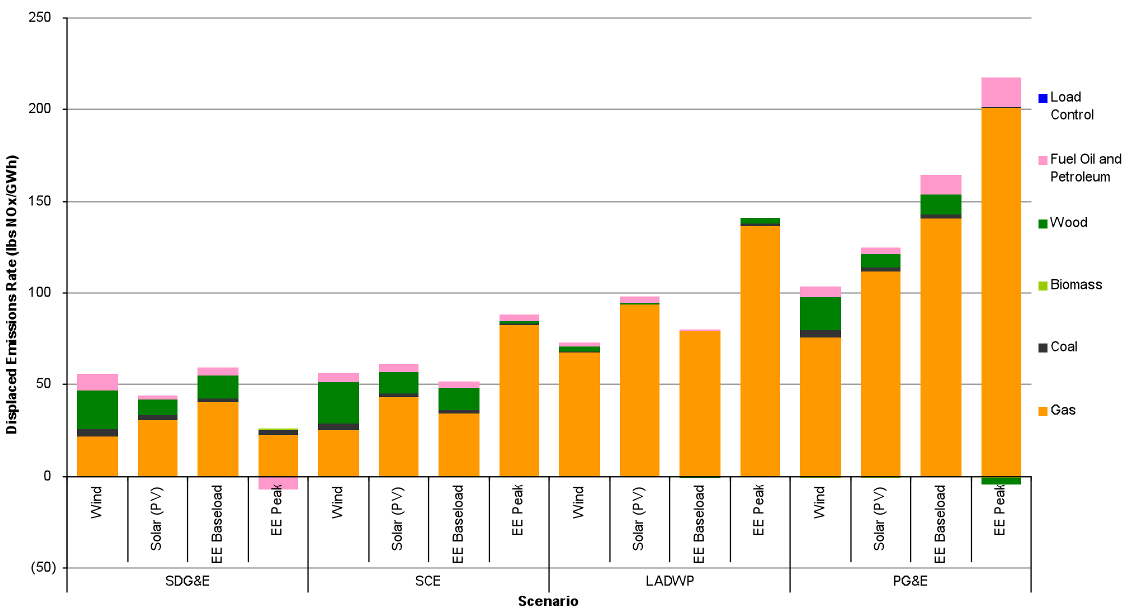
Displaced lbs of NOx per GWh of Energy Displaced, by Air District	SDGE, Wind	SDGE, Solar (PV)	SDGE, EE Baseload	SDGE, EE Peak	SCE, Wind	SCE, Solar (PV)	SCE, EE Baseload	SCE, EE Peak
North CA	1.0 2.7	0.0 2.7	1.5 1.6	-15.7 15.0	1.4 1.6	1.2 2.6	0.3 1.6	-0.8 3.0
Bay North	0.5 0.7	1.1 0.7	1.0 0.4	-1.9 4.1	1.0 0.4	0.7 0.7	1.8 0.4	0.1 0.8
Bay Area	11.6 9.1	7.2 9.0	11.4 5.5	-19.5 50.2	13.1 5.5	13.6 8.9	8.6 5.5	-6.7 10.1
Sierra North	4.4 2.7	-0.8 2.7	4.1 1.6	-10.7 15.0	2.9 1.6	3.1 2.7	2.9 1.6	-2.6 3.0
Sierra South	0.7 0.3	0.4 0.3	0.5 0.2	0.0 1.8	1.0 0.2	0.8 0.3	0.7 0.2	-0.1 0.4
Sacramento	-0.6 0.9	-1.5 0.9	0.2 0.6	-11.3 5.1	0.2 0.6	-0.7 0.9	0.4 0.6	-1.5 1.0
San Joaquin	7.5 7.4	2.8 7.3	7.2 4.4	-46.4 40.8	5.4 4.4	11.8 7.2	5.2 4.4	0.5 8.2
Central Coast	0.7 0.6	3.1 0.6	2.7 0.4	8.2 3.5	3.6 0.4	2.4 0.6	3.6 0.4	9.8 0.7
Desert Region	5.3 3.7	4.3 3.6	3.3 2.2	16.3 20.4	4.9 2.2	4.9 3.6	4.1 2.2	8.7 4.1
South Coast	7.0 6.0	7.9 5.9	9.6 3.6	18.2 33.0	8.6 3.6	8.2 5.8	9.6 3.6	39.0 6.6
San Diego	6.6 4.4	9.3 4.3	9.8 2.6	45.8 24.3	4.3 2.7	5.4 4.3	4.2 2.6	26.4 4.9
Imperial	8.4 1.2	5.6 1.2	6.4 0.7	18.8 6.9	8.6 0.8	7.4 1.2	6.6 0.7	9.8 1.4

Table 6: Displaced NO_X Rate (in lbs NO_X per GWh of EE/RE) for Eight Scenarios by California Air District Region

Displaced lbs of NOx per GWh of Energy Displaced, by Air District	LADWP, Wind	LADWP, Solar (PV)	LADWP, EE Baseload	LADWP, EE Peak	PG&E, Wind	PG&E, Solar (PV)	PG&E, EE Baseload	PG&E, EE Peak
North CA	-0.6 1.7	0.1 2.7	-0.4 1.6	-6.4 10.9	7.7 3.7	5.6 2.8	12.8 1.6	22.2 2.9
Bay North	0.1 0.5	-0.2 0.7	-0.1 0.4	0.9 3.0	3.3 1.0	3.6 0.8	4.0 0.4	2.5 0.8
Bay Area	2.1 5.6	1.7 9.0	-2.5 5.5	-26.1 36.6	27.3 12.5	39.5 9.3	47.2 5.5	69.9 9.7
Sierra North	0.8 1.7	1.2 2.7	-0.7 1.6	-9.2 11.0	11.3 3.8	12.9 2.8	20.5 1.6	29.4 2.9
Sierra South	0.1 0.2	-0.1 0.3	-0.1 0.2	-0.9 1.3	0.8 0.4	0.8 0.3	0.5 0.2	-0.1 0.3
Sacramento	-0.2 0.6	-0.4 0.9	-0.2 0.6	-4.6 3.7	0.9 1.3	2.4 0.9	4.4 0.6	8.5 1.0
San Joaquin	1.5 4.6	3.2 7.3	-0.1 4.4	-10.1 29.7	22.9 10.2	30.6 7.5	43.6 4.4	75.9 7.8
Central Coast	1.5 0.4	1.7 0.6	0.3 0.4	10.5 2.5	6.6 0.9	12.5 0.6	11.8 0.4	8.8 0.7
Desert Region	2.7 2.3	3.8 3.6	2.9 2.2	15.1 14.8	4.5 5.1	4.9 3.8	2.8 2.2	1.1 3.9
South Coast	57.0 3.7	76.3 5.9	74.6 3.6	107.1 24.1	3.0 8.3	0.6 6.1	2.9 3.6	-8.2 6.4
San Diego	4.3 2.7	4.0 4.3	4.0 2.6	41.2 17.7	3.1 6.1	2.3 4.5	1.0 2.6	-2.4 4.7
Imperial	3.0 0.8	2.5 1.2	2.1 0.7	19.7 5.0	8.0 1.7	5.7 1.3	5.6 0.7	2.5 1.3

Much of the displaced NO_X is derived from offset natural gas-fired units in California (see Figure 30, below), although displaced petroleum and biomass are also significant fractions in some EE/RE programs. Overall, the absolute magnitude of displaced NO_X emissions is small in California. However, it is useful to note that the biomass and petroleum fractions of displaced NO_X are a significantly larger fraction of displaced emissions than of generation because of their high absolute emissions rate.

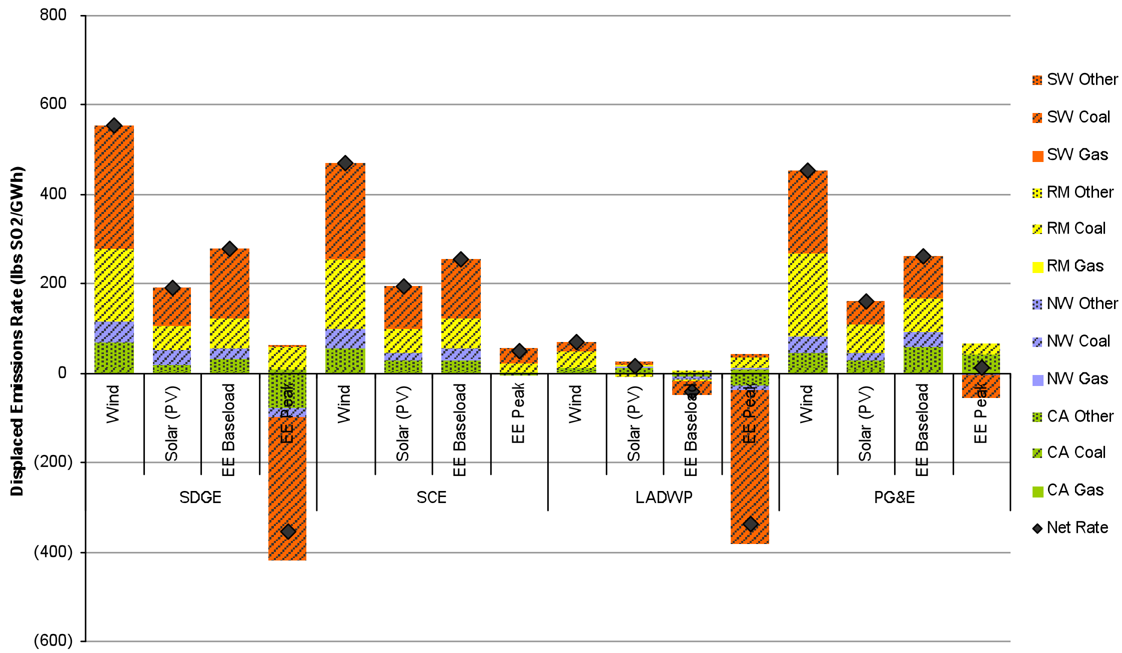
Figure 30: Displaced NO_X (in lbs NO_X / GWh) by Fuel Type in California



Displaced SO_2 Emissions, by Region and Fuel Type

Sulfur dioxide (SO_2) is emitted during the combustion of sulfur-contaminating fuels, particularly coal and petroleum products. These fuel types are limited in California, and therefore, there is a fairly small displaced SO_2 benefit in the state. However, EE/RE implemented in California appear to affect coal generators throughout the West, and result in reduced emissions across the WECC region. Figure 31, below, shows displaced SO_2 emissions throughout the WECC region, again in pounds of SO_2 per GWh, due to the fairly small values, particularly in California.

Figure 31: Displaced SO_2 Emissions Rate (in lbs SO_2/GWh) in by WECC Region and Fuel Type

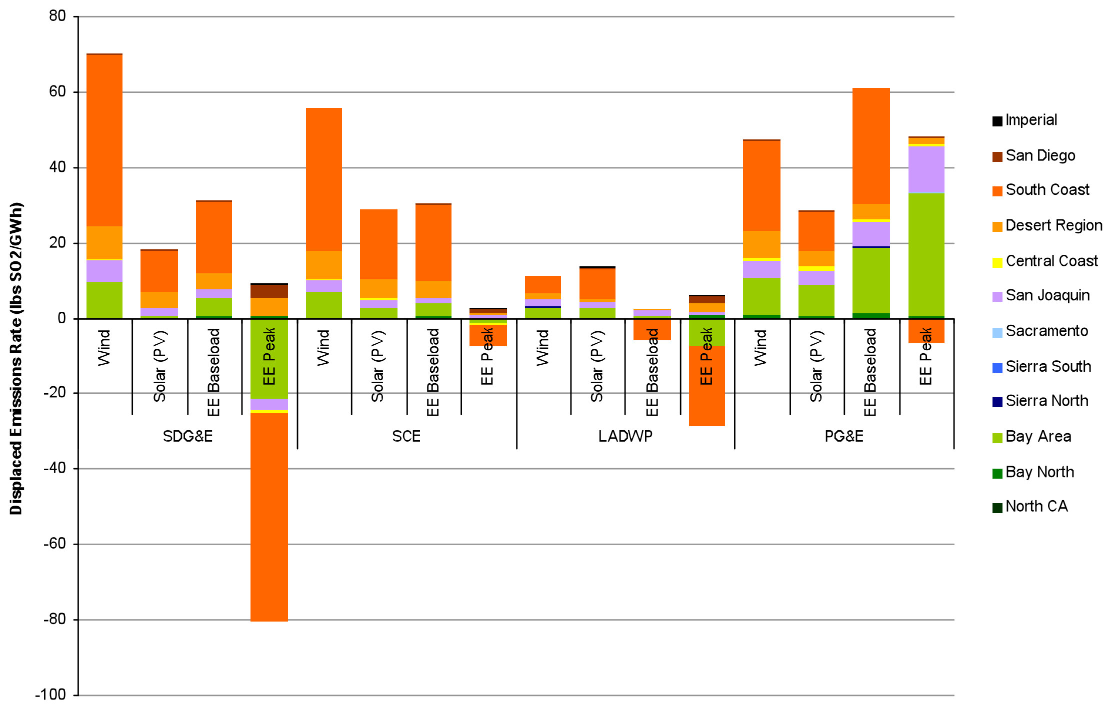


The displaced SO_2 pattern differs from NO_X in that nearly all of the displaced emissions (and added emissions in EE peaking programs) are seen at coal generators, except in California, which is comprised of the "other" category. As will be seen below, these values are primarily associated with displaced coal (or petroleum coke) and petroleum consumption. The negative net displaced emissions of SO_2 in the peaking EE/RE in SDG&E and LADWP are due to increased coal generation in the Southwest; with little SO_2 benefit elsewhere, the result is a net negative emissions rate. Again, the negative displaced emissions rate here is termed "non meaningful" because the uncertainty from multiple model runs exceeds the signal given by the difference between the base case and the scenarios.

Displaced SO_2 Emissions, by Air District Region

Displaced SO_2 emissions rate by air district region are given in Figure 32, below. Much of the displacement is seen in the South Coast and Bay Area air district regions; regions where there are more fuel oil and petcoke displacement opportunities. Overall, the total displaced emissions rate for SO_2 is insignificant (relative to random noise) in nearly all air districts and scenarios except in the Bay Area and South Coast, where significant displacement ranges from 18–45 lbs SO_2/GWh; in no circumstances are any negative displacements (i.e., increase in emissions) significant at a rate of more than 1 lb SO_2/GWh. Tables showing the actual values and significance can be found in **Appendix C**.

Figure 32: Displaced SO_2 Emissions Rate (in lbs SO_2/GWh) by Air District Region



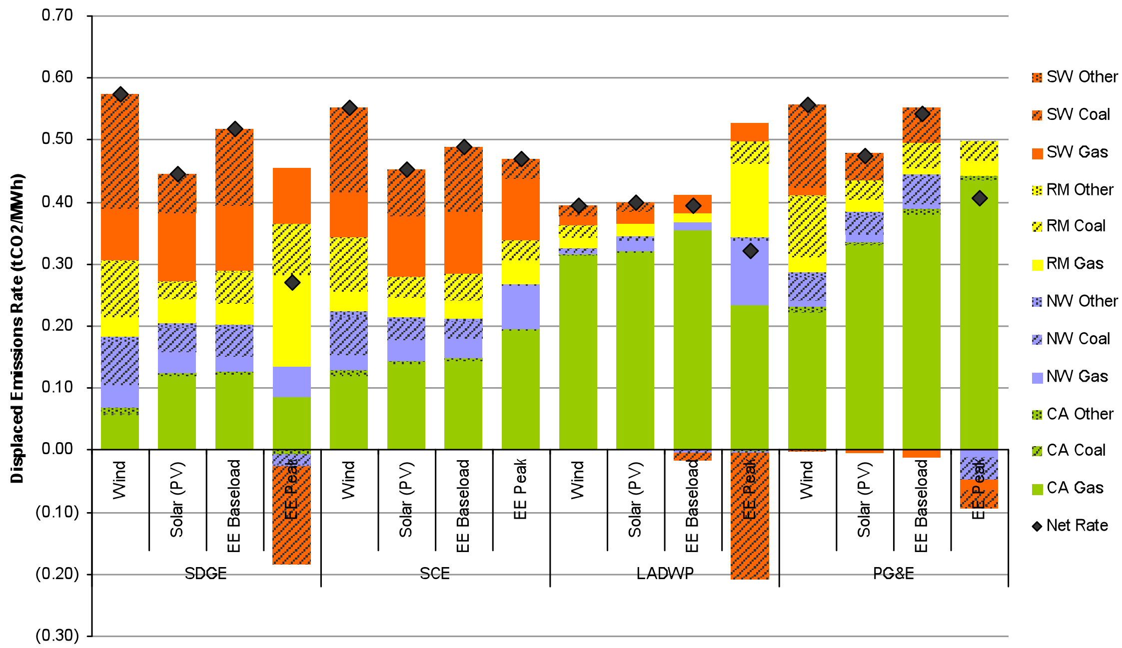
Displaced CO_2 Emissions, by Region and Fuel Type

All combustion sources release carbon dioxide (CO_2), a greenhouse gas pollutant. As a climate change pollutant, CO_2 does not impose damages on populations near the generation source as do criteria pollutants of NO_X and SO_2. Displaced CO_2 emissions are evaluated across all generators in the WECC region. From the perspective of attempting to reduce overall CO_2 emissions from the U.S. generating fleet, the fact that EE/RE in California displace coal generators out of state is a net benefit.

Since most displaceable resources are fossil-fired, net displaced CO_2 emissions are highly related to net displaced energy, with the important caveat that natural gas generation has a CO_2 rate approximately half that of coal generation.[17] It is expected that the overall displaced emissions rate for CO_2 will range between natural gas and coal emissions rates. The regional displaced CO_2 rates for all EE/RE are given in Figure 33, below.

[17] In this model, the WECC-wide average gas CO_2 rate is approximately 0.5 tCO_2/MWh, while the coal rate is about 1.1 tCO_2/MWh.

Figure 33: Displaced CO_2 Emissions (tCO_2 / MWh of EE/RE) by Region and Fuel Type



In regions where the displaced energy is primarily coal, the displaced CO_2 emissions rate is higher (although not markedly so) than regions where the displaced fuel is primarily natural gas.

Detailed results for the displaced CO_2 rate by region and air district region are given in **Appendix C**.

CHAPTER 5:
Discussion and Conclusions

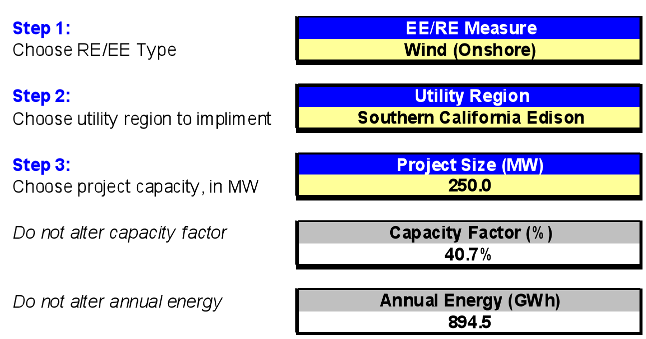
Use of Results for Displaced Emissions Analysis

The analysis presented here has produced values for a displaced emissions rate, designed to be scalable to moderately sized new installations of EE/RE. To estimate the emissions that could be displaced by a new EE/RE program, these values can be applied to the total net saved energy (in MWh) associated with each program. This analysis can be applied to estimate the displaced emissions throughout the WECC region, or within a WECC sub-region or air district region.

Using the accompanying **Data Annex** workbook, one can calculate the displaced emissions, in tons, from any given EE/RE program in any given region. For example, for a program designed to build an additional 250 MW of wind at 35 percent capacity factor wind near the SCE service territory, the expected displaced NO_X emissions would be calculated as follows. The wind farm could be expected to generate approximately 895 GWh of energy per year. Multiplying this energy times the displaced emissions rate for California, the total displacement would be expected at approximately 25.3 tons of NO_X per year, with an error bound of approximately 4.3 tons per year. This project would have the highest impact in the Bay Area, South Coast, and Imperial air districts, displacing approximately 6, 4, and 4 tons of NO_X in each, respectively. The impact of this project on CO_2 is realized primarily outside of California; overall, the project would be estimated to displace 494,000 tons of CO_2, but only about 25 percent of this benefit would be realized in-state.

The above example can be calculated simply using the attached **Data Annex** workbook. In the "Calculator" tab of the worksheet, the user selects "wind" under the EE/RE measure, "Southern California Edison" under the utility region, and enters a capacity of 250 MW. The capacity factor of the project, as implemented in this project, is given, as is the annual energy of the project (see screenshot in Figure 34, below).

Figure 34: Screenshot of Example Project in Selected Region



The average daily load shape and average monthly energy output for this RE project are shown in the accompanying graphs in the **Data Annex**.

Displaced energy and emissions by WECC region and air district region are calculated from model output, and shown in the tables below the input section; results are given in total displaced energy and total displaced emissions (in tons) by WECC region and air district region. In each table cell, the first value is the displaced energy or emissions, and the second value represents the uncertainty range, in the same units. Results that are smaller than the random error are termed "non-meaningful." These non-meaningful results are greyed out. An example results-table screenshot for displaced emissions in air district region is given in Figure 35, below.

Figure 35: Example Screenshot from Data Annex of Displaced Emissions in California Air District Regions from a 250 MW Wind Project in SCE Service Territory

Displaced Energy and Emissions by California AQMD Region				
	Energy Displaced (GWh)	NO_X Displaced (tons)	SO_2 Displaced (tons)	CO_2 Displaced (tons)
North CA	**3.1** *1.8*	0.6 *0.7*	0.0 *0.0*	**1,718** *798*
Bay North	**32.3** *14.8*	**0.4** *0.2*	**0.2** *0.1*	**12,003** *6,358*
Bay Area	**78.6** *16.4*	**5.9** *2.4*	**2.9** *1.4*	**31,106** *8,569*
Sierra North	**25.9** *7.1*	**1.3** *0.7*	0.0 *0.0*	**10,781** *2,903*
Sierra South	**0.2** *0.0*	**0.4** *0.1*	0.0 *0.0*	**185** *26*
Sacramento	**14.7** *4.0*	0.1 *0.2*	0.0 *0.0*	**5,528** *1,715*
San Joaquin	**26.2** *8.5*	**2.4** *2.0*	**1.4** *0.8*	**13,217** *3,697*
Central Coast	**24.3** *8.0*	**1.6** *0.2*	**0.2** *0.0*	**11,926** *5,404*
Desert Region	5.8 *8.1*	**2.2** *1.0*	**3.4** *0.5*	3,228 *3,591*
South Coast	**42.5** *23.0*	**3.9** *1.6*	**16.8** *5.8*	**17,336** *13,607*
San Diego	**20.6** *4.8*	**1.9** *1.2*	0.0 *0.1*	**8,125** *3,167*
Imperial	**9.9** *1.8*	**3.8** *0.3*	0.0 *0.0*	**2,220** *838*

The results presented here are based on EE/RE projects with specific prototypical load shapes, and should be applicable for many or most EE/RE projects contemplated in the region. However, projects with significantly different load shapes than these four for each region would likely result in different, though comparable, emissions benefits.

Patterns of Displacement and Future Research Opportunities

In the West, natural gas-fired resources are primarily on the margin, meaning that in most hours of the year they are more likely to be displaced by EE/RE than other types of resources, such as coal or oil. Therefore, it would be expected first that most displaced generation associated with EE/RE in California and out of state will be natural gas-fired (and will therefore have a fairly low emissions displacement for SO_2 and NO_X), and that these displaced generators will be distributed across the WECC region.

Generally, this pattern holds; however, there are at least three noteworthy exceptions seen in this research:

- A non-intuitive displacement of out-of-state coal was observed in many of the scenarios.
- An apparent increase in coal-fired generation for some of the peaking EE programs.
- A high concentration of natural gas-fired resources are displaced within the LADWP service territory for EE/RE programs enacted within LADWP.

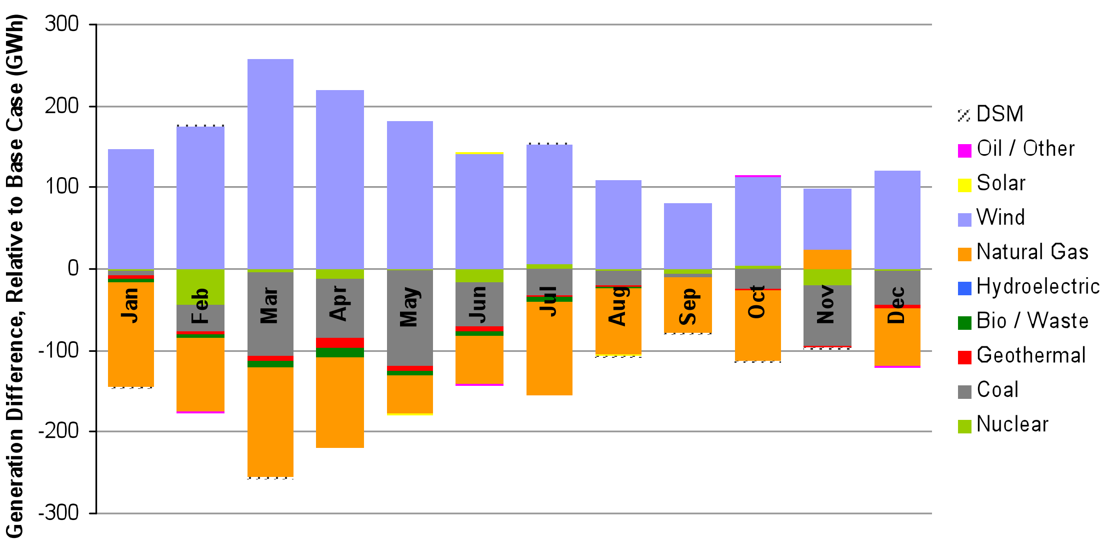
These patterns either illustrate useful lessons about dispatch dynamics within the West or are potentially symptomatic of either inaccurate model constructs or model inputs. The patterns are described in detail below. While some hypotheses can be posed on the reason these patterns emerge, an in-depth exploration of these findings is required to align general expectations or historical system behavior with the patterns seen in this research.

Out-of-State Coal

One surprising aspect of this analysis is that the model indicates that coal-fired generation in the Southwest and Rocky Mountain States can be displaced by some renewable energy and energy efficiency programs in California. In particular, additional wind energy in SDG&E, SCE, and PG&E service territories appear to displace between 26 percent and 33 percent coal,[18] almost exclusively out of state.[19]

A graph of the wind generation and absolute displaced energy in SDG&E appears to confirm that coal is displaced in response to additional wind generation (Figure 36). This graph shows the differences in generation, by fuel type, in the SDG&E wind scenario relative to the base case in 2016. Shaded regions above the horizontal line at zero indicate increased energy output by fuel type—in this case, generally wind, but sometimes natural gas. Shaded regions below the line indicate reduced output by fuel type.

Figure 36: Difference in Monthly Generation across All of WECC between Base Case and SDG&E Wind Scenario, by Fuel Type. The impacts shown result from the addition of 1000 MW of onshore wind in the SDG&E service territory



This chart shows that the greatest coal displacement occurs during the spring and early winter, so-called "shoulder" seasons where regional demand is relatively low and hydroelectric availability is greatest. According to the model results, coal generation in the Intermountain is primarily displaced during the shoulder seasons.

A more detailed examination of hourly patterns of displacement in the shoulder and peak seasons (March and July, in Figure 37 and Figure 38, respectively) for the SDG&E wind scenario shown above suggests that in periods of low demand, coal is displaced on a regular basis, while during the highest consumption months, natural gas is displaced almost exclusively. The spike

[18] SCE and SDG&E, respectively. Coal fractions displaced by utility EE/RE are SCE: 27 ± 4 percent; SDG&E 33 ± 7 percent; PG&E 26 ± 10 percent.

[19] The only California in-state coal generation which appears in this model is petroleum coke burned at refineries; these loads are generally modeled as non-dispatchable because the energy is primarily used on-site for industrial purposes. Therefore there is little available coal in California to be displaced.

in nuclear generation for a day in March is an artifact of a forced outage which occurs in the base case but not in the scenario.

Figure 37: Difference in Hourly Generation across All of WECC between Base Case and SDG&E Wind Scenario, by Fuel Type for a Week in March (2016). The impacts shown result from the addition of 1000 MW of onshore wind in the SDG&E service territory.

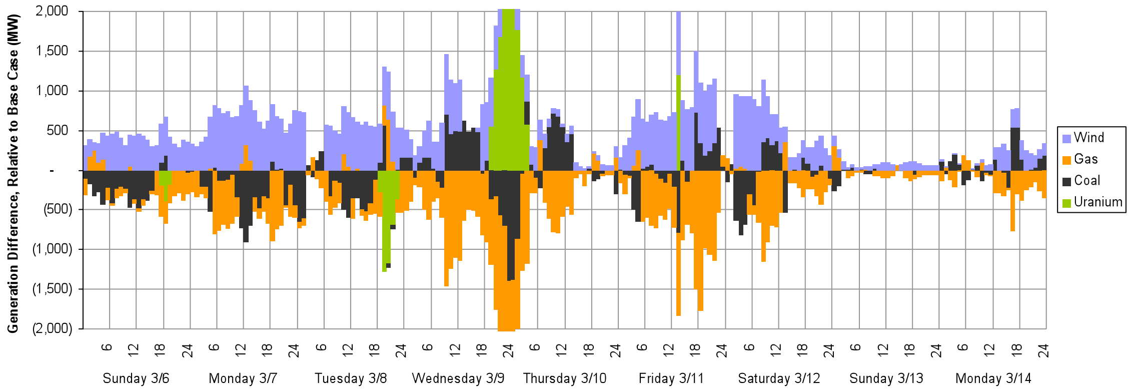
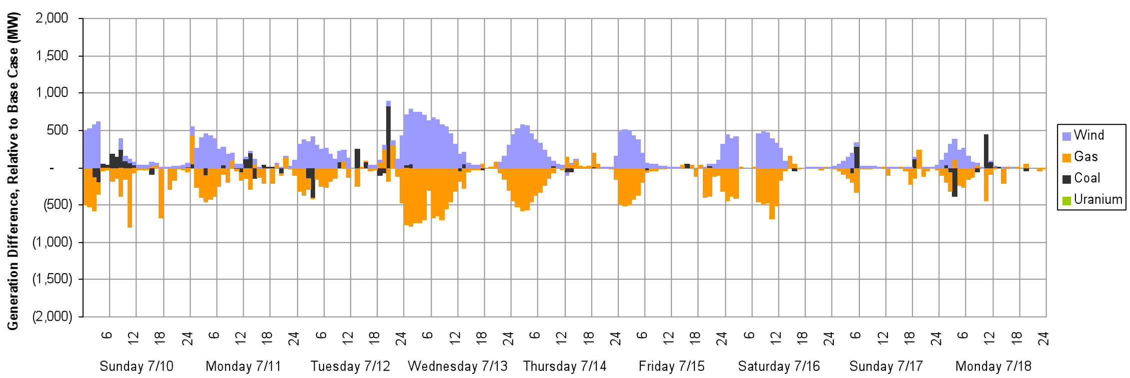


Figure 38: Difference in Hourly Generation across All of WECC Between Base Case and SDG&E Wind Scenario, By Fuel Type for a Week in July (2016). The impacts shown Result from the addition of 1000 MW of onshore wind in the SDG&E service territory.



This seasonal pattern of displacement of out-of-state coal generation, while perhaps counterintuitive, is a consistent feature of the model results.

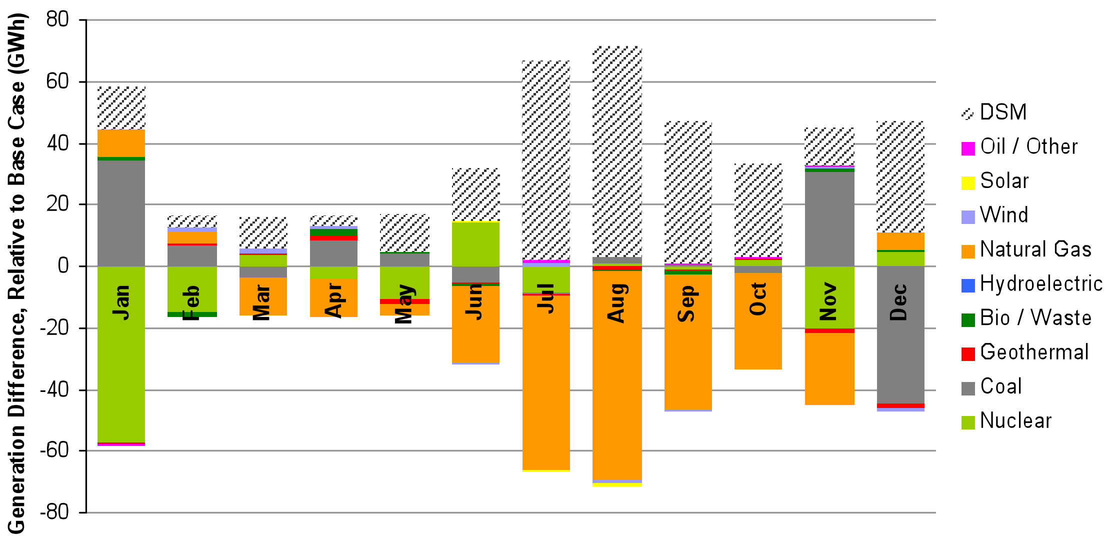
There are several lines of further investigation that are suggested by the displacement of coal from incremental EE/RE. These hypotheses suggest either erroneous assumptions in the model construct, or legitimate questions of operation in the WECC region. One potential hypothesis is that during shoulder seasons, reliability or transmission constraints prevent additional natural gas displacement in the WECC region. Another potential hypothesis is that coal units are forced offline during trough hours and are not able to recommit cost-effectively for on-peak hours. Additionally, it is feasible that the model construct is ill equipped to effectively dispatch thermal resources around deep penetrations of wind. It is notable, for example, that hydroelectric dispatch is never altered in the model runs; as a very inexpensive and flexible resource, one might hypothesize that some amount of hydroelectric energy might be re-dispatched to balance stochastic wind, rather than compel less flexible generation (such as coal) to dispatch around wind. Finally, the model may portray wind patterns in a non-realistic manner, forcing large amounts of wind onto the system simultaneously simply because multiple wind farms are assumed to have an identical load shape. These large, instantaneous insertions of wind might be sufficient to force coal offline in select circumstances.

Negative Displacement Patterns

A second unexpected pattern in this analysis is an apparent *increase* in coal-fired generation in the Southwest associated with EE programs that seek to reduce peak energy use. In both the SDG&E and LADWP peaking EE scenarios, the model predicts that coal generation in the Southwest will *increase* by 10 to 16 percent of the total EE/RE savings—i.e., rather than being displaced, coal generation actually appears to increase.

Peaking EE programs are designed to reduce usage during the highest demand hours, mostly in the summer and winter months. They generally serve to reduce capacity needs, but have a relatively small impact on overall energy use. Parsing the results for the SDG&E analysis by month (Figure 39), the model confirms that the primary impact of the peaking program occurs during mid-summer. However, because the modeled peaking EE program does not have a significant energy impact, the role of noise and random outages is exacerbated relative to the other EE/RE scenarios, and dispatch changes in the model appear somewhat erratic as a result. For example, the coal "additions" in January and November appear to be a response to short forced outages at nuclear units (in this case an outage of several days at Palo Verde, Arizona) rather than explicit responses to energy efficiency programs. This random effect, unrelated to the EE modeled in this scenario, appears large relative to the small energy impact of the program.

Figure 39: Difference in Monthly Generation across All of WECC between Base Case and SDG&E Peaking EE Scenario, by Fuel Type. Much of the observed change in dispatch is due to random generating unit outages, which have a large effect relative to the modest energy-saving impact of a peaking EE program.



Again, examining the hourly patterns of displacement in both April and July (in Figure 40 and Figure 41, respectively) it is clear that the EE peaking program tends to target natural gas-fired resources for most hours. The large increase in coal and decrease in natural gas during the middle of the March period is likely due to a forced outage difference and *not* due to the peaking program. This representation suggests that the total energy displaced by an EE peaking program provides insufficient signal for a relatively high level of noise.

Figure 40: Difference in Hourly Generation across All of WECC between the Base Case and SDG&E Peaking EE Scenario, by Fuel Type for a Week in March (2016). The impacts shown result from the addition of an aggressive EE peak demand program targeting the 90th percentile highest load hours in SDG&E service territory.

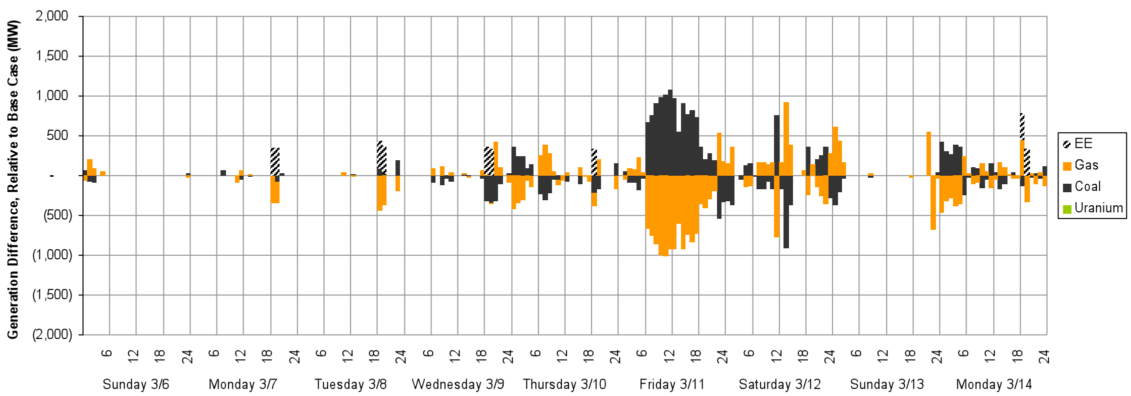
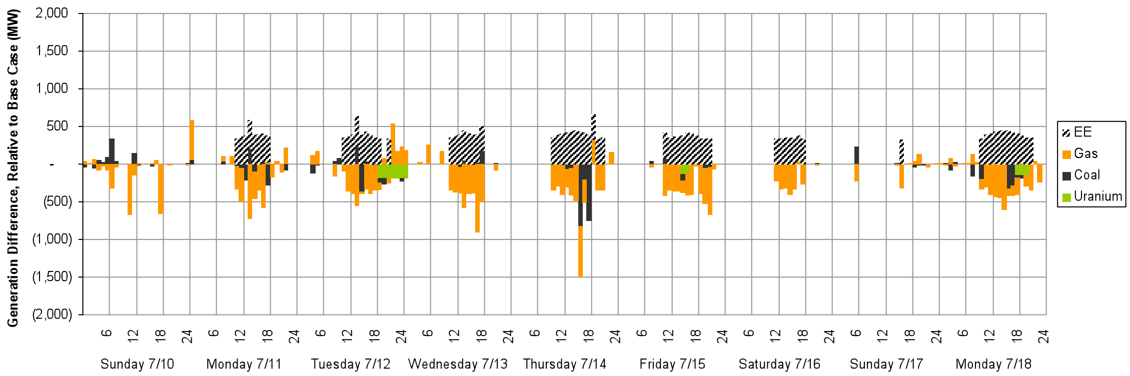


Figure 41: Difference in Hourly Generation across All of WECC Between Base Case and SDG&E Peaking EE Scenario, by Fuel Type for a Week in March (2016). The impacts shown result from the addition of an aggressive EE peak demand program targeting the 90th percentile highest load hours in SDG&E service territory.



The poor signal-to-noise given in the EE peaking scenarios suggests further lines of research to overcome this particular obstacle. Many modeling constructs allow users to fix forced outages to a particular schedule, such that individual scenarios can be compared on a one-to-one basis. However, an analysis examining only the operating margin (as in this research) should be aware of the impact of random events on the shape of the outcome. It should be considered whether a small program that affects the margin in a large and complicated system such as WECC should be considered in an explicit dispatch model, as presented here, or whether it is sufficiently characterized by simpler analyses. In addition, in other regions aside from California, the displacement of potentially high emissions peakers may have a larger impact than that found in this analysis.

Concentration of Displacement in LADWP Service Territory

New EE/RE resources in LADWP service territory appear to displace, almost exclusively, natural gas resources in LADWP. This is potentially a surprising result: if transmission is unconstrained between LADWP and adjacent service territories, it would be expected that displacement in LADWP might look similar, if not identical, to nearby service territories (such as SCE). Even more surprising is that, according to spot checks, the displacement occurs with new and efficient combined-cycle (CC) units (i.e., the Valley and repowered Haynes and Magnolia CC units). It would normally be assumed that these units are lower cost, and therefore less likely to be displaced at the operating margin, suggesting that the displacement is potentially due to either a commit or transmission constraint.

One potential explanation as to why, in the model, the displacement occurs with these new and/or efficient units has to do with how the model might choose to dispatch local versus non-local resources. LADWP obtains a large fraction of power directly from the Intermountain Power Project (IPP), a coal plant in Utah. Further, IPP is directly linked, both in the model and in reality, with LADWP through a direct current connection, and the utility maintains a take-or-pay contract with the plant. However, IPP also serves other utilities in California and throughout the West. It is feasible that in the model construct, IPP is dispatched *not* on behalf of LADWP, but in consideration of other requirements, and in the model LAWDP essentially is compelled to accept the coal. If the model, in reaching equilibrium, does not re-dispatch resources outside of LADWP to otherwise transfer this power out of the LADWP service territory, existing resources in LADWP might need to derate to accept IPP power. Given a large insertion of yet additional wind power, the only option (again, according to this model construct) might be for LADWP resources to derate and accept must-take wind power. It is unclear if LADWP dispatch would operate in the manner described above, but clearly this is a critical question for understanding displaced energy and emissions in the Los Angeles basin.

Model Assumptions and Caveats

Assumptions and model constructs used in this research may result in systematic errors; other fundamental aspects of the electricity market simply cannot be captured by this model; and constructing an analysis based on a theoretical build-out in a future year invites additional uncertainty. There are significant caveats and assumptions used to forecast future policies, decisions, and economic trends, as well as to streamline model use, runtime, and results. These assumptions include, but are not limited to the following:

- **Model topology:** The PROSYM model uses a simplified topology, or mapping, to achieve faster runtime and simpler outputs. This nodal topology assumes that generation within specific power control areas ("nodes") are unconstrained by transmission within that node, and only transmission-constrained between nodes. The transmission between nodes is also simplified and aggregated, rather than tracing specific power lines. The effect on generators in the model is that real transmission constraints may not be captured due to a user's choice of topology; subtle differences between prices at different generators may not be captured; and some ancillary requirements may be lost. These types of errors are more important at the margin, and therefore may have a more profound effect on this study's results.

- **Fuel costs:** Generation dispatch relies heavily on the estimated variable costs of operation, which include fuel costs, operation and maintenance costs, and any emissions costs. Changes in relative generation merit due to fuel prices or emissions costs could markedly change our expectations of the marginal units affected by EE/RE. This research uses fixed Energy Commission assumptions of fuel prices in 2016 as of 2009, which may not reflect our current estimate of fuel prices (or uncertainty in fuel prices) by 2016.[20] Indeed, run output from the scenarios indicates that natural gas and coal are often on the margin (i.e., displaced by EE/RE), suggesting that changes in fuel prices could change the expected avoided generation and, subsequently, avoided emissions.

- **Emissions costs:** The model, in keeping with assumptions of the Energy Commission in the model construct, does not utilize any emissions costs. In California, as elsewhere, federal and local environmental regulations enforce various cap-and-trade and other pricing mechanisms for criteria emissions. For example, under the U.S. EPA's Acid Rain Program, all U.S. electric generating units (EGU) over 25 MW are required to hold allowances for SO_2 emissions, effectively establishing a market price for the pollutant. This price has fluctuated between under \$100/tSO_2 to several hundred dollars per ton, spiking at over \$1,500/tSO_2 in 2005 (nominal) (U.S. EPA 2010b). At higher prices, these SO_2 emissions costs can account for up to 5 to 10 percent of a coal unit's running cost.[21] In California, CARB plans for the Assembly Bill 32 (AB32) create a cap-and-trade program for CO_2 (CARB 2010), which will similarly establish a market price for CO_2 emissions from power produced in or entering California. These prices are specifically designed to change dispatch dynamics, discouraging high-emissions units and

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[20] For example, since 2009, significant new natural gas discoveries have lowered gas prices in 2010–2011 (as well as in most near-term forecasts); while increasing international demand for U.S. coal has driven up coal costs. While a dispatch tradeoff between gas and coal may not be triggered only by these fuel prices, changes in fuel costs could significantly change the marginal resource.

[21] Author's estimate: Assuming SO_2 emissions rate of 4 lbs SO_2/MWh, an example price of \$500/tSO_2 results in a cost adder of \$1/MWh, or 5 percent of a \$20/MWh running cost.

promoting low-CO_2 generation. However, a price reflecting this program is also absent from the model construct.

- **Generation retirements:** The model, which was originally designed to review California policy, may not reflect expected changes in out-of-state generation over the next decade. In particular, recently proposed and expected U.S. EPA regulations further restricting criteria emissions and water use are expected to result in numerous changes to elements of the existing fleet, particularly coal EGU. At the time of this writing, at least four utilities in WECC had announced various coal retirements or repowering over the next two decades (but with highly uncertain timing), including Portland General Electric (Oregon) (Reuters 2010), TransAlta Corporation (Washington) (Reuters 2011), Arizona Public Service Co. (Arizona) (Navajo Nation Council 2011), and Xcel (Colorado) (Xcel Energy. 2010.). Some of these changes in the fleet composition may precede the compliance deadline of 2015 for U.S. EPA's rules, meaning that in our analysis year (2016), the fleet composition may look different than that expected by the Energy Commission as of 2009. Without extensive and ongoing forward-going planning, these types of changes are not feasibly captured within this type of analysis, but must be recognized as a significant source of uncertainty.
- **Stochastic wind dispatch**: In the model structure, the stochastic nature of wind is handled in at least two distinct mechanisms.
    - In some areas, wind farms are given an explicit hourly load shape, often derived from anemometer data and physical wind-flow models. These patterns, however, are fixed: in each run, the wind farm generates exactly the same amount of energy at each hour. When this mechanism is used in a comparative model, such as the analysis presented here, it ensures that each run represents a similar wind behavior. However, the model, which has "perfect foresight" may unrealistically compensate for wind patterns when in reality, a dispatcher may have little notice of rising or falling wind availability. All wind and solar farms represented for displacement purposes are modeled with an explicit load shape.
    - As a default setting, in some regions, wind farms are simply assigned a random outage factor for each month, and a short "recovery" period after a forced outage. This mechanism yields a random wind pattern with no distinct hourly pattern, and no consistency between model runs. The inconsistent approach may yield greater variance (error, or noise) between runs than is warranted for this analysis, but may represent the stochastic nature of wind more accurately overall.

The simplifying assumptions used here have an unknown impact on the model or the results. For the purposes of this research, it is assumed that the impacts are less severe than the random nature of the forced outages discussed in the *Random Error* section of Chapter 3. These questions and uncertainties are important, and should be considered carefully in future research.

Regulatory Implementation

To transition this model from a pilot study to an analysis of real, enforceable EE and RE programs, there are a variety of steps which should be taken, including:

Physical Build-Out Assumptions: The model used here relied on a best estimate of build-out as given by the California Energy Commission, in an early representation of the 33 percent renewable energy standard, compliance with a CO_2 emissions reduction program, new efficiency standards, and conversion of old natural gas units with once-through cooling to more rigorous controls or new plants. However, the model does not represent regulatory changes that occur in other states, new transmission being built in WECC, or other state policies. An accurate model would correctly represent both California policies, as well as existing and expected environmental regulations (including the Air Toxics rule, improvements and retirements due to the Regional Haze Rule, and renewable energy standards in other states) and new plants expected across the WECC region. This broad base of assumptions may require a regionally accepted model framework, but could also be used to accurately model emissions reductions in other states.

Fuel and Emissions Costs: The model is currently built with default fuel costs for coal, oil, and natural gas, but has no emissions costs. With changing fuel availability and prices (lower natural gas price projections since the time this model was created) and emissions regulations, the model would require updated projections and potentially a range of fuel and emissions costs for the purposes of evaluating multiple uncertainties.

Monte Carlo Analysis: This research provides a mechanism for evaluating uncertainty due only to forced outage rates. However, for forward-looking models, uncertainty in prices for fuels and emissions, as well as uncertainty in hydrological conditions, can affect the emissions benefit of EE/RE at the margin. A preferred approach might be to run a true Monte Carlo analysis within each scenario, evaluating random combinations of forced outages, prices, and hydrology in order to generate an expected value outcome and a broadly applicable uncertainty to each element of this analysis, rather than simply stating that some results are "non-meaningful."

Viable EE/RE Programs: This research utilized four distinct load shapes for EE/RE programs of wind, solar, baseload, and peaking efficiency programs, all implemented at a large-scale (1000 MW). In a regulatory implementation using a Monte-Carlo analysis to quantify error and uncertainty, using regionally or locally viable EE/RE program load shapes might produce more meaningful output.

Evaluate Generator Constraints: The results of this study include non-intuitive findings, such as the fairly large displacement of out-of-state coal. These results imply potentially incorrectly parameterized coal and hydroelectric behavior under certain conditions. Even small changes in how these and other units respond could significantly affect behavior at the margin. Therefore, a regulatory implementation of this study should thoroughly evaluate parameterizations that result in behaviors non-typical in the WECC region.

Peak Emissions Reporting: Air quality standards usually regulate short-term exposures, rather than annual average exposures. Therefore, while the annual displaced emissions rate is a useful metric in this analysis, it is not necessarily the metric that would be required by an air district to quantify the efficacy of a particular emissions-reduction program. The model used here works natively as an hourly model, but this study only extracted final output at a monthly time step. In a regulatory framework, the peak emissions displacement, or an estimate of the range of peak displacement, would hold a high value for regulatory compliance.

Conclusions

This research was designed to model the criteria pollution and GHG emissions benefits in California from renewable energy (RE) and energy efficiency (EE) implemented within the State. The research resulted in several key findings:

Dispersed Criteria Emissions Benefits

As shown in this research and elsewhere, the Western grid is highly interconnected, and therefore changes in load, generation, or resource availability in one part of the West impact generators throughout the entire WECC system. As a result, criteria emissions benefits from EE/RE programs implemented in California are highly dispersed throughout the WECC region.

Thus, while there are important emissions benefits associated with these programs, those benefits are not all available for California Air Districts to comply with SIP requirements. However, this research finds that there are significant benefits accrued to other Western states from California demand reductions.

Those benefits which do accrue to California are generally distributed among multiple districts, often far beyond the original locus of the EE/RE programs themselves. According to the model results, EE/RE programs in LADWP and PG&E tend to displace local resources (in LADWP and Northern California, respectively) more often than EE/RE programs in SCE and SDG&E.

The analysis shown here was not originally scoped to include non-California entities in results, with the exception of greenhouse gas benefits. In comparing out-of-state criteria emissions benefits to California benefits, this analysis may unfairly overemphasize out-of-state emissions benefits. In particular, charts such as Figure 28, which shows displaced pounds of NO_X per GWh of generation, show very little relative benefit of EE/RE in California and fairly large benefits out of state. This disproportionate benefit is almost entirely a function of California's relatively low emissions generating fleet and the large number of uncontrolled generators throughout the Intermountain West.

It is clear that there may be significant opportunities for cooperation across air districts and even throughout the WECC region to rely upon low-cost EE/RE programs to displace emissions, even if those emissions are not confined to a single air district, or even a single state. Across states and regions, the combined emissions benefit of EE/RE can be quite high, suggesting that there may be significant benefit to cooperative air and energy planning across air district, state, and regional boundaries. With a focus on single air districts, the programs examined in this analysis appear to be less effective.

Greenhouse Gas Benefits

A notable benefit identified in this analysis is that EE/RE programs have a large displacement out-of-state, often displacing coal-fired resources in the Rocky Mountain and Southwest regions of WECC. Because of this coal displacement, the greenhouse gas benefit of the EE/RE programs is higher than it would be if the displacement were within California only. In many of the programs, displacing a combination of California natural gas and out-of-state coal (such as in the SDG&E wind scenario) results in a 50 percent increase in GHG emissions benefit (0.6 tCO_2/MWh) relative to displacing in-state natural gas only (such as in the LADWP baseload EE scenario, 0.4 tCO_2/MWh).

Verify Emissions from Existing Resources

The utility of electric system dispatch models to analyze air quality benefits from EE/RE was significantly advanced by Phase 2 of this project, but not in the way originally intended. Synapse's assessment of the input assumptions in the model found that the emissions data for electric generating units was inconsistent, and was not based on actual stack emissions, or was inconsistent with data reported to U.S. EPA by the same generating units. Since the focus of this phase was to assess how and to what degree EE/RE affects generating units, ensuring that emissions data are correct was crucial to the precision of the modeling results.

The importance of correcting emissions cannot be overstated, particularly in an already low-emissions state like California. Prior to the emissions correction undertaken in this analysis, the estimated NO_X emissions from California EGU were 230 percent higher than values reported by the U.S. EPA, and SO_2 values in the model exceeded reported emissions by over 500 percent. Without a correction, the emissions for the state would be incorrectly modeled, and the emissions benefit could be incorrect by a large margin.

The most dramatic changes in the emissions correction exercise were observed in small, very high emissions generating resources, such as biomass generators and refineries (**see**

Appendix A). While these units contribute very little energy overall to California, their emissions are significant enough that small changes in generation at these units have a large and disproportionate impact on overall California stationary source emissions. It is concluded that verifying, reporting, and correcting the emissions from these and other units in California is of paramount importance for correct emissions modeling in the State.

Peak Reduction Uncertainty

In nearly all of the examples of peak energy reduction EE programs, the displaced energy and emissions benefits are small and subsumed by random error in the model. In some cases, the net regional emissions benefit appears to be negative, due to a displacement of low-emissions natural gas in California and an *increase* in high-emissions coal in the Intermountain West. These coal increases are almost all below the level of noise in this analysis. However, the consistent appearance of this pattern across multiple scenarios suggests that peak reduction programs may be counterproductive as an emissions-reduction mechanism for California. In particular, if decreases in peak energy demands (or load shifting from peak to off-peak hours) allow greater commitment of high-emissions baseload units such as coal, then the net change may not be beneficial from an emissions standpoint. [22] It should be emphasized that this result is highly uncertain and potentially an outcome specific to the modeling construct and assumptions of this research.

Uncertainty in Emissions Benefits

Where the benefit of EE/RE is broadly distributed, the generations and emissions "signal" associated with program energy savings is diluted in both random and non-random changes throughout WECC ("noise" and systematic error or changes). Therefore, while Synapse has chosen EE/RE programs that are fairly ambitious in scale (1000 MW of wind and solar, 333 MW of baseload reduction, or 10 percent of peak load reduction in each service territory) it is often difficult to distinguish the absolute changes in generation and emissions due to the EE/RE program from the random changes in the model. This is a persistent source of uncertainty in this sort of modeling exercise, and indeed in empirical observation: random variance in the electrical grid is often as large as, or larger than, displaced energy.

Closing

It is clear that there are reduced pollutant emissions benefits, both local and regional, to be gained from certain EE/RE programs in California. Many of these benefits are often found out-of-state due to the integrated nature of the western electricity grid. In some cases the benefits are quite modest, as for EE programs that target peak load reduction rather than a high volume of energy savings. In the peak-load reducing cases, the model results even suggest that certain programs have the seemingly paradoxical effect of increasing emissions, if they lead to a dispatch scenario involving greater reliance on coal. It is unclear whether this is a real effect or an artifact of the model structure.

The results of this research suggest that there is ample opportunity for inter-district and even regional cooperation to define EE/RE emissions benefits. If air districts collaborate to reduce energy use, the emissions benefits throughout the region can be substantial. It is less clear that individual air quality regions can realize much local emissions benefit by acting alone. In fact, the model results indicate that regional modeling and coordination is critical for SIP compliance, and that regional energy and multi-pollutant planning will be a crucial strategy for

[22] Load shifting or reductions in peak load may allow baseload units to operate at a higher capacity factor or more often because either they do not need to ramp down during off-peak hours, or they can maintain a higher level of commitment when peaking units are not required.

progress as traditional mechanisms for achieving emissions reductions, such as end-of-pipe controls, become less available.

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Appendix A: Emissions Corrections for California EGU

Background

For the purposes of evaluating criteria and greenhouse gas emissions displaced through energy efficiency (EE)/renewable energy (RE) projects in California Air Districts, an accurate emissions baseline is required and more specifically, an accurate baseline set of emissions for each generator is required. It is imperative that the emissions rates represented in the generation dispatch model reflect a best understanding of emissions rates at electric generating units (EGU) for both baseline and displaced emissions purposes.

In preliminary studies, Synapse found that total criteria emissions from combustion EGU in California according to output from the dispatch model do not reflect recent estimates from U.S. EPA datasets. Further investigation revealed that emissions from a fairly small fraction of combustion generators both contributed to total criteria emissions and were responsible for a large fraction of the discrepancies between the dispatch model (the Ventyx PROSYM model, or here, simply "Ventyx") and U.S. EPA reported emissions. To rectify these discrepancies, Synapse adjusted emissions rates at selected California EGU to reflect the most recently available, vetted U.S. EPA emissions data.

This appendix describes adjustments made to the emissions rates of California EGU as represented in the Ventyx model to reflect our best understanding of emissions rates in advance of the EE/RE incremental modeling performed for this study. The appendix is organized to discuss emissions before and after adjustment (Findings), the method used to estimate and compare emissions against U.S. EPA data (Approach), and detailed changes made to emissions for the largest emitting sources.

Findings

Emissions by Unit Type

Synapse examined emissions from California EGU as modeled for analysis year 2012, the earliest year available in the dispatch software as calibrated for modeling in the 2009 California Integrated Energy Policy Report (2009 IEPR). Examining the Ventyx inputs, Synapse found that there were no significant adjustments made to criteria or greenhouse gas emissions from individual EGU relative to recent historic data.

It is expected that the only differences which would be found between individual EGU emissions in model year 2012 and reported historic U.S. EPA data are due to differences in historic and future dispatch. Generally, in the absence of adjustments, emissions rates on a pounds or tons per MWh or million Btu (MMBtu) basis would be expected to remain consistent between recent historic years and the 2012 model year. Adjustments which might be expected could include changes to default Ventyx emissions rates or emissions characteristics, or expected changes in emissions rates due to more stringent environmental regulations or controls. Synapse found no adjustments, suggesting that there should be reasonable comparisons between emissions rates from the U.S. EPA and the Ventyx model.

According to initial model outputs, Synapse found that a fairly small amount of generation within California state lines, accounting for only 13 percent of generation, emitted 68 percent of oxides of nitrogen (NO_X) and 82 percent of sulfur dioxide (SO_2) in the state. These units fell into three categories: natural gas-fired units which did not report emissions to the U.S. EPA via the continuous emissions monitoring system (CEMS),[23] petroleum-fired units, and wood units. Natural gas-fired units which *did* report emissions to the CEMS system account for a large fraction of remaining generation (25 percent) yet only emitted 5 percent of total NO_X from stationary sources, according to the model output for 2012.

Table A-1, below, shows a breakdown of the fraction of generation and emissions from units of a particular type, subdivided by existing units and "Future Generation." i.e., units which did not exist in either the CEMS dataset from 2009 *or* at the time the last U.S. EPA validated emissions records were published (at the time of this study, 2005 data in the 2007 Emissions and Generation Resource Integrated Database [eGRID] record). Non-emitting resources, such as hydroelectric, geothermal, wind, and solar generators, account for the majority of generation in the test year.

Table A-1: Fractions of Generation, CO_2, NO_X, and SO_2 by Unit Categorization, in California, in Model Test Year (2012) Before Adjustment. Only units in the category marked "Gas (in CEMS)" report emissions directly to the U.S. EPA via CEMS.

	Count	Fraction of Generation (%)	Fraction of NOx (%)	Fraction of SO_2 (%)
Coal	8	1	15	18
Natural Gas (in CEMS)	196	25	5	0
Natural Gas (not in CEMS)	156	11	48	0
Petroleum	8	1	8	82
Fuel Oil	9	0	0	0
Biomass	41	1	3	0
Refuse	3	0	1	0
Wood	28	2	12	0
Future Generation	36	7	8	0
Non-Emitting	344	52	0	0
Total	**829**	**100**	**100**	**100**

Erroneous Emissions Rates

The significant discrepancy between emissions emanating from natural gas units which are in the CEMS database and natural gas units which are *not* in the CEMS database, as well as a large discrepancy between U.S. EPA estimated total stationary source emissions in California and emissions as estimated in the Ventyx model, compelled Synapse to check emissions rates from units in the model. Synapse found that emissions from non-CEMS reporting natural gas, petroleum, and biomass units represented in the model in California were not in agreement with U.S. EPA estimates of source emissions. For example, using the default emissions rates in the Ventyx model, total NO_X in California amounted to 50.1 thousand tons per year from stationary sources, yet the U.S. EPA estimates only 22.3 thousand tons of annual NO_X in 2005 in

[23] U.S. EPA. 2009. Clean Air Markets Division (CAMD) emissions data. Available online at http://camddataandmaps.epa.gov/gdm/.

California.[24] Further, while the U.S. EPA estimates approximately 13.6 thousand tons of SO_2 emissions in California in 2005, the model estimated nearly 71 thousand tons in the 2012 test year.

Through investigation, Synapse found that the emissions rates from units which report to the CEMS system were generally accurate and derived directly from CEMS data. However, many other units, including coal, natural gas, petroleum, and wood-fired units, had anywhere from moderately incorrect to egregiously incorrect emissions rates estimates, according to U.S. EPA data. Most units in the Ventyx model (as received) had emissions rates far in excess of those recorded in California. In a small number of cases, the Ventyx model underestimated SO_2 emissions rates. In general, new electrical generating units expected to be built in the future had a higher emissions rate than many existing units.

Emissions Rates Adjustments

Synapse assumed that:

- U.S. EPA data represented in the CEMS and eGRID data were generally more accurate than the model assumptions, and
- new generators built in California would likely have emissions rates comparable to the best existing generators in California today.

For the purposes of emissions correction, Synapse used a "base case" model run: the 20 percent renewable energy standard (RES) scenario for a near-term reference year, 2012. To compare emissions from the model, Synapse used and cross referenced three sources of emissions data:

- the Ventyx Market Analytics[25] output from the "base case,"
- data reported to U.S. EPA's CEMS for 2009, and
- the U.S. EPA's eGRID for 2005.

The eGRID database is an inventory of generation and emissions characteristics of electric generating systems. It includes all plants that provide power to the electric grid and report data to the U.S. government. Where possible, it uses CEMS data; elsewhere it integrates data from U.S. EPA, the Energy Information Administration (EIA), and the Federal Energy Regulatory Commission (FERC).[26]

Where feasible, each emitting unit in California was mapped from the Ventyx model output to a known generator in either the CEMS data or in the eGRID dataset. Units which could not be positively identified ("No Information") were not adjusted; in total 68 units of 829, amounting to 2.4 percent of generation, could not be positively identified.

To enact the above assumptions, Synapse first adjusted SO_2 and NO_X emissions rates on a unit-by-unit basis where U.S. EPA data were available, either from existing CEMs data or in the validated eGRID dataset, and where the unit could be positively identified and associated with

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[24] U.S. EPA. 2007. eGRID. Available online at http://www.epa.gov/cleanenergy/documents/egridzips/eGRID2007_Version1-1_xls_only.zip.

[25] The actual results are from the Market Analytics interface for the PROSYM model, part of a Ventyx software suite.

[26] More information on eGRID can be found here: http://www.epa.gov/cleanenergy/energy-resources/egrid/faq.html.

U.S. EPA data. Further, the SO_2 and NO_X emissions rates of units built in the future were adjusted to match the lowest 10th percentile of emissions in the California today.

Existing Units

Emissions rates for existing units in the model were adjusted if the unit could be positively identified (i.e., correlated with an existing U.S. EPA-recorded unit), the output emissions rates (in lbs/MWh) differed from an U.S. EPA recorded rate by ±20 percent, and the unit generated at least 100 GW in the test year 2012. In this analysis, 120 units met the above criteria and were adjusted.

- SO_2 emissions rates were adjusted using CEMS data for eight (8) natural gas-fired units, reducing estimated emissions by 1.7 tons of SO_2 in California in 2012 (Table A-3, below).
- SO_2 emissions rates were adjusted dramatically using eGRID data for 11 petroleum and coal-fired units (almost all non-dispatchable industrial users), reducing estimated emissions by 61,892 tons of SO_2 in 2012. (Table A-4, below)
- NO_X emissions rates were adjusted using CEMS data for 26 natural gas units (almost all non-dispatchable industrial users), reducing estimated emissions by 345 tons of NO_X in 2012. (Table A-5 below)
- NO_X emissions rates were adjusted using eGRID data for 75 natural gas, wood, and petroleum-fired units, reducing estimated emissions by 27,012 tons of NO_X in California in 2012 (Table A-6 through Table A-8 below).

Units for which both eGRID and CEMS data existed were corrected preferentially using the CEMS data. Units for which SO_2 emissions were underestimated in the model could generally not be adjusted upwards (17 units).

Future Units

Emissions rates for future units in the model were adjusted if the unit emitted SO_2 or NO_X in the 2012 test year and was activated in the model (i.e., built) after 2009. In total, 45 units met this criteria and were adjusted.

- SO_2 emissions rates for future units were adjusted using the lowest 10th percentile of emissions for nine (9) biomass and natural gas-fired units, reducing estimated emissions by 1.1 tons of SO_2 in 2012 (Table A-9, below).
- NO_X emissions rates for future units were adjusted using the lowest 10th percentile of emissions for 36 biomass, wood and natural gas-fired units, reducing estimated emissions by 461.1 tons of NO_X in 2012 (Table A-10 and Table A-11, below).

Testing Adjustments

To test if total emissions of NO_X and SO_2 in the model were more closely aligned with measured values after the correction, Synapse calculated aggregate emissions from each unit type. Aggregate emissions by fuel type before and after adjustment are given in Table A-2, below, and compared against U.S. EPA estimates from the 2005 eGRID dataset.

NO_X and SO_2 rates were altered markedly for coal, petroleum, and wood-fired units, as well as natural gas units not in the CEMS database. Overall, NO_X estimated by the model in California dropped from 50.1 to 22.3 thousand tons. Primarily due to alterations of only 11 units (almost all refineries), SO_2 emissions dropped in the model from 70.8 to 8.9 thousand tons. This reduction brings the overall SO_2 emissions in the model *below* U.S. EPA estimated SO_2 emissions in 2012. Seventeen (17) units, accounting for 2.3 percent of generation, reported SO_2 emissions rates above those estimated by the U.S. EPA. Due to the way SO_2 is estimated in the model construct, it was deemed restrictively difficult to alter SO_2 emissions in an upwards direction for most units.[27]

[27] Emissions of SO_2 are modeled in the Ventyx system as a function of the fuel type burned at the unit, the estimated sulfur content of the fuel, the heat rate of the unit, and the fraction of SO_2 which is captured by any scrubber technologies. Due to a lack of data on the units of interest, Synapse was unable to find sufficient information to justify either an alteration in unit fuel use, sulfur content, or heat rate—any of which could change the SO_2 emissions rate. Therefore, Synapse only altered SO_2 capture rates; these cannot be brought below 0 percent to simulate a higher emissions rate than that given by the fuel and heat rates.

Table A-2: Aggregate Emissions Rates of NO_X and SO_2 by Unit Categorization, in California Only, Before and After Adjustment (2012)

		NOx (tons)		SO_2 (tons)	
	Generation (GWh)	Pre-Adjustment	Post-Adjustment	Pre-Adjustment	Post-Adjustment
Coal	2,699	7,448	1,468	12,593	3,376
Natural Gas (in CEMS)	55,160	2,481	2,136	129	127
Natural Gas (not in CEMS)	23,328	24,250	8,556	74	74
Petroleum	1,322	3,806	871	58,013	5,337
Fuel Oil	0	1	1	1	1
Biomass	2,426	1,498	1,084	9	9
Refuse	414	752	680	-	-
Wood	3,293	5,907	3,990	-	-
Future Generation	15,170	4,020	3,559	26	25
Non-Emitting	113,365	-	-	-	-
Total	**217,177**	**50,162**	**22,343**	**70,844**	**8,949**
U.S. EPA Estimate for CA	**199,925**	**22,302**		**13,577**	

No Changes in Emissions Due to New Regulations

Synapse did not make changes in existing or future unit generation to adjust for any future emissions regulations, including either the Clean Air Act Regional Haze (BART) rules or the proposed Clean Air Act Air Toxics rule. Synapse did not evaluate how these rules might change emissions, heat rate, or dispatch dynamics of generators in or outside of California.

Detailed Adjustments

The following sections of this appendix have tables indicating explicit adjustments made to 120 existing units and 45 future units. As noted above, all adjusted existing units fell outside of a ±20 percent emissions rate threshold relative to U.S. EPA estimates (either CEMS or eGRID) and produced over 100 GWh in the 2012 test year. All fossil or biomass fired units expected to emit in the future were adjusted to match the best performing 10th percentile of units today in California.

Each table below gives the unit name as supplied by Ventyx, the unit name as given by either the U.S. EPA in eGRID or in the CEMS dataset, the primary fuel type as given in the model, as well as the closest city (by ZIP code), and the air district encompassing the unit ZIP code.

Table A-3: SO_2 Emissions Rate Corrections for California Electric Generating Facilities Based on CEMS (2009) Emissions Rates

Ventyx Model Name	CEMS / eGRID Name	Fuel Type	City, State	Air District Region	Model Generation in 2012 (GWh)	Pre-Adjustment SO_2 Emissions (tons)	Ventyx Assumed SO_2 Removal Rate (%)	Ventyx Assumed SO_2 Emissions Rate (lbs/MWh)	CEMS Estimated SO_2 Emission Rate (lbs/MWh)	Synapse Adjusted SO_2 Removal Rate (%)
CARSON ICE CG CC	Carson Cogeneration Co.	Gas	Elk Grove, CA	South Coast	392	1.2	0%	0.006	0.005	21
COALINGA COG 100	Coalinga Cogeneration Co.	Gas	Coalinga, CA	San Joaquin	289	1.2	0%	0.008	0.006	22
HUNTINGTON BEA 2	AES Huntington Beach	Gas	Huntington Beach, CA	South Coast	486	2.0	0%	0.008	0.007	18
LA PALOMA 1	La Paloma Generating Plant	Gas	Mc Kittrick, CA	San Joaquin	110	0.3	0%	0.005	0.004	23
MOUNTAINVIEW 4A	Mountainview Power Co.	Gas	San Bernardino, CA	South Coast	117	0.3	0%	0.005	0.004	18
ROSEVILLE ENE 1A	Roseville Energy Park	Gas	Roseville, CA	Sierra North	415	1.2	0%	0.006	0.004	24
ROSEVILLE ENE 1B	Roseville Energy Park	Gas	Roseville, CA	Sierra North	411	1.2	0%	0.006	0.004	25
YUBA CITY 1	Yuba City Energy Center	Gas	Yuba City, CA	Sierra North	141	0.4	0%	0.006	0.005	18

Table A-4: SO_2 Emissions Rate Corrections for California Electric Generating Facilities Based on eGRID (2007) Emissions Rates

Ventyx Model Name	CEMS / eGRID Name	Fuel Type	City, State	Air District Region	Model Generation in 2012 (GWh)	Pre-Adjustment SO_2 Emissions (tons)	Ventyx Assumed SO_2 Removal Rate (%)	Ventyx Assumed SO_2 Emissions Rate (lbs/MWh)	eGRID Estimated SO_2 Emission Rate (lbs/MWh)	Synapse Adjusted SO_2 Removal Rate (%)
BP WILMINGTON 1	BP Wilmington Calciner	Petroleum	Tujunga, CA	South Coast	209	9,182.0	0	87.849	34.824	60
EAST THIRD STR 1	East Third Street Power Plant	Petroleum	Pittsburg, CA	Bay Area	171	7,504.2	0	87.754	1.358	98
HANFORD COGEN 1	Hanford	Petroleum	Hanford, CA	San Joaquin	183	8,013.7	0	87.435	0.446	99
LOVERIDGE ROAD 1	Loveridge Road Power Plant	Petroleum	Pittsburg, CA	Bay Area	136	5,995.0	0	87.990	1.093	99
MT POSO COGEN 1	Mt Poso Cogeneration	Coal	Bakersfield, CA	San Joaquin	419	2,931.6	0	13.996	2.979	79
NICHOLS ROAD 5	Nichols Road Power Plant	Petroleum	Pittsburg, CA	Bay Area	171	7,510.8	0	87.828	1.096	99
PORT OF STOCKT 1	Port of Stockton District Energy	Coal	Stockton, CA	San Joaquin	380	2,671.0	0	14.073	0.898	94
SFAR CARBON 1	Phillips 66 Carbon Plant	Petroleum	Rodeo, CA	Bay Area	126	5,542.4	0	87.725	18.564	79
STOCKTON COGEN 1	Stockton Cogen	Coal	Stockton, CA	San Joaquin	473	4,667.2	0	19.749	1.093	94
WILBUR EAST 4	Wilbur East Power Plant	Petroleum	Antioch, CA	Bay Area	171	7,514.3	0	87.863	1.106	99
WILBUR WEST 3	Wilbur West Power Plant	Petroleum	Antioch, CA	Bay Area	154	6,750.1	0	87.789	1.364	98

Table A-5: NO_X Emissions Rate Corrections for California Electric Generating Facilities Based on CEMS (2009) Emissions Rates

Ventyx Model Name	CEMS / eGRID Name	Fuel Type	City, State	Air District Region	Model Generation in 2012 (GWh)	Pre-Adjustment NOx Emissions (tons)	Ventyx Assumed NOx Emissions Rate (lbs/MWh)	CEMS Estimated NOx Emission Rate (lbs/MWh)	Synapse Adjusted NOx Input Rate (lbs/MMBtu)
CARSON COGEN C 1	Carson Ice-Gen Project	Gas	Carson, CA	Sacramento	356	12.8	0.072	0.151	0.013
CARSON ICE CG CC	Carson Cogeneration	Gas	Elk Grove, CA	South Coast	392	25.4	0.130	0.073	0.006
GILROY POWER P 1	Gilroy Peaking Energy Center	Gas	Gilroy, CA	Bay Area	103	30.5	0.593	0.419	0.035
GRAYSON CC BC	Grayson	Gas	Glendale, CA	South Coast	217	52.2	0.480	0.321	0.027
HAYNES 5	Haynes	Gas	Long Beach, CA	South Coast	271	8.1	0.060	0.044	0.004
HIGH DESERT P 1A	High Desert Power Plant	Gas	Adelanto, CA	Desert Region	125	4.5	0.072	0.105	0.009
HIGH DESERT P 1B	High Desert Power Plant	Gas	Adelanto, CA	Desert Region	144	5.2	0.072	0.100	0.008
HIGH DESERT P 1C	High Desert Power Plant	Gas	Adelanto, CA	Desert Region	123	4.5	0.073	0.100	0.008
HUNTINGTON BEA 1	AES Huntington Beach LLC	Gas	Huntington Beach, CA	South Coast	489	14.1	0.058	0.226	0.019
KING CITY COGE 1	King City Power Plant	Gas	King City, CA	Central Coast	890	196.6	0.442	0.157	0.013
LOS MEDANOS E 1A	Los Medanos Energy Center	Gas	Pittsburg, CA	Bay Area	1,962	62.0	0.063	0.048	0.004
MAGNOLIA REPOW 1	Magnolia Power Project	Gas	Burbank, CA	South Coast	1,760	14.4	0.016	0.042	0.004
Malburg 1a	Malburg	Gas	Los Angeles, CA	South Coast	239	6.1	0.051	0.255	0.021
Malburg 1b	Malburg	Gas	Los Angeles, CA	South Coast	237	6.1	0.051	0.254	0.021
Otay Mesa 1a	Otay Mesa Energy Center	Gas	Jamul, CA	San Diego	1,327	50.7	0.076	0.049	0.004
Otay Mesa 1b	Otay Mesa Energy Center	Gas	Jamul, CA	San Diego	1,332	50.7	0.076	0.039	0.003
PALOMAR ESCON 1A	Palomar Energy Center	Gas	Escondido, CA	San Diego	1,393	35.0	0.050	0.041	0.003
PASTORIA CC 1B	Pastoria Energy Facility LLC	Gas	Bakersfield, CA	San Joaquin	1,193	30.7	0.051	0.040	0.003
PASTORIA CC 1C	Pastoria Energy Facility LLC	Gas	Bakersfield, CA	San Joaquin	1,273	32.5	0.051	0.040	0.003
ROSEVILLE ENE 1B	Roseville Energy Park	Gas	Roseville, CA	Sierra North	411	7.8	0.038	0.053	0.004
SARGENT CANYON 1	Sargent Canyon Cogeneration	Gas	King City, CA	Central Coast	297	13.9	0.094	0.137	0.012
SCATTERGOOD 2	Scattergood	Gas	Playa Del Rey, CA	South Coast	431	7.1	0.033	0.023	0.002
SCATTERGOOD 3	Scattergood	Gas	Playa Del Rey, CA	South Coast	641	6.3	0.020	0.028	0.002
SOUTH BAY 1	South Bay Power Plant	Gas	Chula Vista, CA	San Diego	344	22.9	0.133	0.110	0.009
SPA CAMPBELL C 1	SPA Cogen 3	Gas	Sacramento, CA	Sacramento	1,164	39.0	0.067	0.087	0.007
YUBA CITY 1	Greenleaf 2 Power Plant	Gas	Yuba City, CA	Sierra North	141	368.6	5.237	1.685	0.142

Table A-6: NO_X Emissions Rate Corrections for California Electric Generating Facilities Based on eGRID (2007) Emissions Rates (1 of 3)

Ventyx Model Name	CEMS / eGRID Name	Fuel Type	City, State	Air District Region	Model Generation in 2012 (GWh)	Pre-Adjustment NOx Emissions (tons)	Ventyx Assumed NOx Emissions Rate (lbs/MWh)	eGRID Estimated NOx Emission Rate (lbs/MWh)	Synapse Adjusted NOx Input Rate (lbs/MMBtu)
ACE COGEN 1	ACE Cogeneration Facility	Coal	Trona, CA	Desert Region	752	1,945.5	5.173	0.823	0.069
BADGER CREEK 1	Badger Creek Cogen	Gas	Bakersfield, CA	San Joaquin	192	429.4	4.466	0.782	0.066
BEAR MOUNTAIN 1	Bear Mountain Cogen	Gas	Bakersfield, CA	San Joaquin	366	817.5	4.465	0.782	0.066
BERRY COGEN	Berry Cogen	Gas	Taft, CA	San Joaquin	295	806.8	5.468	0.782	0.066
BERRY PLACERIT 1	Berry Placerita Cogen	Gas	Newhall, CA	South Coast	137	358.1	5.215	0.782	0.066
BERRY PLACERIT 2	Berry Placerita Cogen	Gas	Newhall, CA	South Coast	137	357.3	5.204	0.782	0.066
BP WILMINGTON 1	BP Wilmington Calciner	Petroleum	Tujunga, CA	South Coast	209	602.4	5.763	3.685	0.310
BURNEY FOR PRO 1	Burney Forest Products	Wood	Burney, CA	North CA	217	388.6	3.576	7.000	0.589
CHALK CLIFF CG 1	Chalk Cliff Cogen	Gas	Maricopa, CA	San Joaquin	366	817.3	4.464	0.782	0.066
CORONA COGEN 1	Corona Cogen	Gas	Corona, CA	South Coast	389	1,049.2	5.394	0.782	0.066
DELANO ENERGY 1	Delano Energy	Wood	Delano, CA	San Joaquin	138	245.2	3.549	1.660	0.140
DELANO ENERGY 2	Delano Energy	Wood	Delano, CA	San Joaquin	113	193.9	3.440	1.660	0.140
DOUBLE C LTD DC1	Double C	Gas	Bakersfield, CA	San Joaquin	183	444.3	4.853	0.782	0.066
DOUBLE C LTD DC2	Double C	Gas	Bakersfield, CA	San Joaquin	183	444.5	4.856	0.782	0.066
E F OXNARD 1	Indeck West Enfield Energy	Gas	Port Hueneme, CA	Central Coast	132	348.5	5.268	3.672	0.309
EAST THIRD STR 1	East Third Street Power Plant	Petroleum	Pittsburg, CA	Bay Area	171	492.3	5.757	0.558	0.047
FW MARTINEZ 1A	Martinez Refining	Gas	Concord, CA	Bay Area	348	79.1	0.455	0.800	0.067
FW MARTINEZ 1B	Martinez Refining	Gas	Concord, CA	Bay Area	348	79.1	0.454	0.800	0.067
HANFORD COGEN 1	Hanford	Petroleum	Hanford, CA	San Joaquin	183	525.8	5.737	0.311	0.026
HIGH SIERRA HS1	High Sierra	Gas	Bakersfield, CA	San Joaquin	183	484.3	5.290	0.782	0.066

HIGH SIERRA HS2	High Sierra	Gas	Bakersfield, CA	San Joaquin	183	484.2	5.289	0.782	0.066
HL POWER PLANT 1	HL Power	Wood	Litchfield, CA	North CA	141	252.8	3.579	1.524	0.128
KERN FRONT L KF1	Kern Front	Gas	Bakersfield, CA	San Joaquin	183	484.6	5.294	0.782	0.066
KERN FRONT L KF2	Kern Front	Gas	Bakersfield, CA	San Joaquin	183	484.5	5.292	0.782	0.066

Table A-7: NO_X Emissions Rate Corrections for California Electric Generating Facilities Based on eGRID (2007) Emissions Rates (2 of 3)

Ventyx Model Name	CEMS / eGRID Name	Fuel Type	City, State	Air District Region	Model Generation in 2012 (GWh)	Pre-Adjustment NOx Emissions (tons)	Ventyx Assumed NOx Emissions Rate (lbs/MWh)	eGRID Estimated NOx Emission Rate (lbs/MWh)	Synapse Adjusted NOx Input Rate (lbs/MMBtu)
KERN RIVER C TAG	Kern River Cogeneration	Gas	Bakersfield, CA	San Joaquin	541	243.0	0.898	0.599	0.050
KERN RIVER C TBG	Kern River Cogeneration	Gas	Bakersfield, CA	San Joaquin	542	243.0	0.897	0.599	0.050
KERN RIVER C TCG	Kern River Cogeneration	Gas	Bakersfield, CA	San Joaquin	542	243.0	0.897	0.599	0.050
KERN RIVER C TDG	Kern River Cogeneration	Gas	Bakersfield, CA	San Joaquin	542	243.1	0.898	0.599	0.050
LASSEN 1	Wheelabrator Lassen	Gas	Redding, CA	North CA	105	298.0	5.700	0.782	0.066
LIVE OAK LIMIT 1	Johnsonburg Mill	Gas	Bakersfield, CA	San Joaquin	366	942.8	5.149	1.216	0.102
LOVERIDGE ROAD 1	Loveridge Road Power Plant	Petroleum	Pittsburg, CA	Bay Area	136	393.3	5.773	0.560	0.047
MCKITTRICK LTD 1	McKittrick Cogen	Gas	Bakersfield, CA	San Joaquin	366	947.7	5.176	0.782	0.066
MECCA 1	Mecca Plant	Wood	Mecca, CA	South Coast	290	503.2	3.470	1.423	0.120
MENDOTA BIOMAS 1	AES Mendota	Wood	Kerman, CA	San Joaquin	171	306.3	3.587	2.584	0.217
MID SET COGEN 1	Mid-Set Cogeneration	Gas	Bakersfield, CA	San Joaquin	294	782.5	5.320	0.782	0.066
MIDWAY SUNSET A	Midway Sunset Cogen	Gas	Mc Kittrick, CA	San Joaquin	628	539.4	1.717	0.495	0.042
MIDWAY SUNSET B	Midway Sunset Cogen	Gas	Mc Kittrick, CA	San Joaquin	634	544.9	1.718	0.495	0.042
MIDWAY SUNSET C	Midway Sunset Cogen	Gas	Mc Kittrick, CA	San Joaquin	628	539.5	1.718	0.495	0.042

MT POSO COGEN 1	Mt Poso Cogeneration	Coal	Bakersfield, CA	San Joaquin	419	1,176.0	5.615	0.908	0.076
NICHOLS ROAD 5	Nichols Road Power Plant	Petroleum	Pittsburg, CA	Bay Area	171	492.7	5.761	0.563	0.047
OILDALE ENERGY 1	Oildale Cogen	Gas	Bakersfield, CA	San Joaquin	303	853.9	5.639	0.782	0.066
OXNARD 2	Oxnard	Gas	Oxnard, CA	Central Coast	165	367.4	4.463	0.782	0.066
PORT OF STOCKT 1	Port of Stockton District Energy Fac	Coal	Stockton, CA	San Joaquin	380	1,071.5	5.645	1.704	0.143
PUENTE HILLS 1	Puente Hills Energy Recovery	Biomass	Whittier, CA	South Coast	388	358.1	1.845	0.372	0.031
REDDING CC 1	Redding Power	Gas	Redding, CA	North CA	222	2.1	0.019	0.025	0.002
Richmond CG 1	Richmond Cogen	Gas	#N/A	Bay Area	286	233.8	1.638	0.808	0.068
Richmond CG 2	Richmond Cogen	Gas	#N/A	Bay Area	286	233.7	1.637	0.808	0.068
RIO BRAVO FRES 1	Rio Bravo Fresno	Wood	Fresno, CA	San Joaquin	146	265.4	3.626	1.062	0.089
RIO BRAVO JASM 1	Rio Bravo Jasmin	Coal	Bakersfield, CA	San Joaquin	225	640.0	5.678	0.825	0.069

Table A-8: NO_X Emissions Rate Corrections for California Electric Generating Facilities Based on eGRID (2007) Emissions Rates (3 of 3)

Ventyx Model Name	CEMS / eGRID Name	Fuel Type	City, State	Air District Region	Model Generation in 2012 (GWh)	Pre-Adjustment NOx Emissions (tons)	Ventyx Assumed NOx Emissions Rate (lbs/MWh)	eGRID Estimated NOx Emission Rate (lbs/MWh)	Synapse Adjusted NOx Input Rate (lbs/MMBtu)
RIO BRAVO POSO 1	Rio Bravo Poso	Coal	Bakersfield, CA	San Joaquin	338	961.5	5.696	0.900	0.076
RIO BRAVO ROCK 1	Rio Bravo Rocklin	Wood	Lincoln, CA	Sierra North	144	259.0	3.591	1.270	0.107
RIPON COGEN 1	Ripon Mill	Gas	Ripon, CA	San Joaquin	375	1,014.7	5.411	0.782	0.066
SAN GABRIEL CO 1	San Gabriel Facility	Gas	San Gabriel, CA	South Coast	310	859.5	5.553	0.782	0.066
SERRF MSW 1	Southeast Resource Recovery	Refuse	Long Beach, CA	South Coast	218	393.6	3.618	2.956	0.249
SFAR CARBON 1	Phillips 66 Carbon Plant	Petroleum	Rodeo, CA	Bay Area	126	363.6	5.755	3.661	0.308
SHASTA WHLBRT 1	Wheelabrator Shasta	Wood	Redding, CA	North CA	152	278.5	3.665	2.118	0.178
SHASTA WHLBRT 2	Wheelabrator Shasta	Wood	Redding, CA	North CA	152	278.4	3.664	2.118	0.178
SHASTA WHLBRT 3	Wheelabrator Shasta	Wood	Redding, CA	North CA	152	278.4	3.664	2.118	0.178
SPI BURNEY 1	Sierra Pacific Burney Facility	Wood	Burney, CA	North CA	109	202.1	3.700	0.774	0.065
SPI QUINCY 1	Sierra Pacific Quincy Facility	Wood	Quincy, CA	Sierra North	180	332.5	3.693	0.888	0.075

STOCKTON COGEN 1	Stockton Cogen	Coal	Stockton, CA	San Joaquin	473	1,328.2	5.620	0.313	0.026
SYCAMORE COG GTA	Sycamore Cogeneration	Gas	Bakersfield, CA	San Joaquin	590	514.6	1.744	0.573	0.048
SYCAMORE COG GTB	Sycamore Cogeneration	Gas	Bakersfield, CA	San Joaquin	590	514.5	1.744	0.573	0.048
SYCAMORE COG GTC	Sycamore Cogeneration	Gas	Bakersfield, CA	San Joaquin	590	514.7	1.745	0.573	0.048
SYCAMORE COG GTD	Sycamore Cogeneration	Gas	Bakersfield, CA	San Joaquin	590	514.4	1.744	0.573	0.048
TRACY BIOMASS 1	Tracy Biomass	Wood	Tracy, CA	San Joaquin	136	242.8	3.563	0.094	0.008
US BORAX 1	US Borax	Gas	Bakersfield, CA	Desert Region	290	819.6	5.647	1.035	0.087
WADHAM ENERGY 1	Wadham Energy LP	Biomass	Williams, CA	Bay North	121	217.7	3.597	1.488	0.125
WATSON COGEN 1A	Watson Cogeneration	Gas	Carson, CA	South Coast	739	162.2	0.439	0.065	0.006
WATSON COGEN 1B	Watson Cogeneration	Gas	Carson, CA	South Coast	739	162.0	0.438	0.065	0.006
WATSON COGEN 1C	Watson Cogeneration	Gas	Carson, CA	South Coast	739	162.1	0.439	0.065	0.006
WATSON COGEN 1D	Watson Cogeneration	Gas	Carson, CA	South Coast	739	162.0	0.438	0.065	0.006
WILBUR EAST 4	Wilbur East Power Plant	Petroleum	Antioch, CA	Bay Area	171	493.0	5.765	0.569	0.048
WILBUR WEST 3	Wilbur West Power Plant	Petroleum	Antioch, CA	Bay Area	154	442.8	5.759	0.562	0.047
WOODLAND BIOMA 1	Woodland Biomass Power Ltd	Wood	Woodland, CA	Bay North	150	269.3	3.583	1.264	0.106

Table A-9: SO_2 Emissions Rate Adjustments for Future California Electric Generating Facilities; Based on Lowest 10th Percentile Emissions for Fuel Type

Ventyx Model Name	Ventyx Model Description	Fuel Type	Ventyx Assumed Physical Location	Air District Region	Model Generation in 2012 (GWh)	Pre-Adjustment SO_2 Emissions (tons)	Ventyx Assumed SO_2 Emissions Rate (lbs/MWh)	10th Percentile SO_2 Emission Rate for fuel Type (lbs/MWh)	Synapse Adjusted SO_2 Removal Rate (%)
SOUTHERN SAN ST	Southern San Diego Biomass Energy	Biomass	SDG&E	Bay North	191	0.5	0.0052	0.0048	8.8
COLUSA GENER 1A	Colusa Generating Station: CC1	Gas	PG&E	Bay North	1,056	2.4	0.0045	0.0040	11.5
COLUSA GENER 1B	Colusa Generating Station: CC1	Gas	PG&E	Bay North	1,076	2.4	0.0045	0.0040	9.9
GENCC_IID	Generic New CC for L/R Balance	Gas	IID	Imperial	534	1.1	0.0041	0.0040	2.5
GENCC_SMUD2012_1	Generic New CC for 2012+	Gas	SMUD	Bay North	1,454	3.0	0.0041	0.0040	2.6
GENCC_SMUD2012_2	Generic New CC for 2012+	Gas	SMUD	Bay North	1,427	3.0	0.0042	0.0040	4.4
INLAND EMPIRE 2	Inland Empire Energy Center: CS2	Gas	SCE	South Coast	2,699	5.5	0.0041	0.0040	1.4
OTC REPLACE SD1	Generic New CC for L/R Balance	Gas	SDG&E	San Diego	538	1.2	0.0045	0.0040	9.9
OTC REPLACE SD2	Generic New CC for L/R Balance	Gas	SDG&E	San Diego	544	1.2	0.0044	0.0040	8.9

Table A-10: NO_X Emissions Rate Adjustments for Future CA Facilities; Based on Lowest 10th Percentile Emissions for Fuel Type (1 of 2)

Ventyx Model Name	Ventyx Model Description	Fuel Type	Ventyx Assumed Physical Location	Air District Region	Model Generation in 2012 (GWh)	Pre-Adjustment NOx Emissions (tons)	Ventyx Assumed NOx Emissions Rate (lbs/MWh)	10th Percentile NOx Emission Rate for fuel Type (lbs/MWh)	Synapse Adjusted NOx Input Rate (lbs/MMBtu)
SOUTHERN SAN ST	Southern San Diego Biomass	Biomass	SDG&E	Bay North	191	285.7	2.996	0.449	0.038
COLUSA GENER 1A	Colusa Generating Station: CC1	Gas	PG&E	Bay North	1,056	38.0	0.072	0.047	0.004
COLUSA GENER 1B	Colusa Generating Station: CC1	Gas	PG&E	Bay North	1,076	38.6	0.072	0.047	0.004
CPV SENTINEL GT1	CPV Sentinel Energy Project: GT1	Gas	SCE	South Coast	33	4.6	0.276	0.047	0.004
CPV SENTINEL GT2	CPV Sentinel Energy Project: GT2	Gas	SCE	South Coast	30	4.1	0.275	0.047	0.004
CPV SENTINEL GT3	CPV Sentinel Energy Project: GT3	Gas	SCE	South Coast	26	3.5	0.271	0.047	0.004
CPV SENTINEL GT4	CPV Sentinel Energy Project: GT4	Gas	SCE	South Coast	28	3.8	0.267	0.047	0.004
CPV SENTINEL GT5	CPV Sentinel Energy Project: GT5	Gas	SCE	South Coast	33	4.3	0.262	0.047	0.004
ESCONDIDO POWE 2	Escondido: GEN2	Gas	SDG&E	San Diego	4	0.6	0.267	0.047	0.004
GENAD_NBAJA_1001		Gas		San Diego	143	19.3	0.270	0.047	0.004
GENCC_IID	Generic New CC for L/R Balance	Gas	IID	Imperial	534	18.5	0.069	0.047	0.004
GENCC_SMUD2012_1	Generic New CC for 2012+	Gas	SMUD	Bay North	1,454	50.5	0.069	0.047	0.004
GENCC_SMUD2012_2	Generic New CC for 2012+	Gas	SMU	Bay North	1,427	49.2	0.069	0.047	0.004
GENGT_NBAJA_1001		Gas		San Diego	20	6.1	0.619	0.047	0.004
GENGT_NBAJA_1201		Gas		San Diego	27	8.4	0.633	0.047	0.004
HUMBOLDT BAY C1	Humboldt Bay: IC 1	Gas	PG&E	North CA	41	5.3	0.256	0.047	0.004
HUMBOLDT BAY C10	Humboldt Bay: IC 10	Gas	PG&E	North CA	42	5.3	0.252	0.047	0.004
HUMBOLDT BAY C2	Humboldt Bay: IC 2	Gas	PG&E	North CA	42	5.3	0.254	0.047	0.004
HUMBOLDT BAY C3	Humboldt Bay: IC 3	Gas	PG&E	North				0.047	0.004

				CA	41	5.1	0.248		
HUMBOLDT BAY C4	Humboldt Bay: IC 4	Gas	PG&E	North CA	42	5.3	0.252	0.047	0.004
HUMBOLDT BAY C5	Humboldt Bay: IC 5	Gas	PG&E	North CA	41	5.2	0.251	0.047	0.004
HUMBOLDT BAY C6	Humboldt Bay: IC 6	Gas	PG&E	North CA	42	5.2	0.251	0.047	0.004
HUMBOLDT BAY C7	Humboldt Bay: IC 7	Gas	PG&E	North CA	42	5.3	0.255	0.047	0.004
HUMBOLDT BAY C8	Humboldt Bay: IC 8	Gas	PG&E	North CA	42	5.4	0.259	0.047	0.004

Table A-11: NO_X Emissions Rate Adjustments for Future Facilities; Based on Lowest 10th Percentile Emissions for Fuel Type (2 of 2)

Ventyx Model Name	Ventyx Model Description	Fuel Type	Ventyx Assumed Physical Location	Air District Region	Model Generation in 2012 (GWh)	Pre-Adjustment NOx Emissions (tons)	Ventyx Assumed NOx Emissions Rate (lbs/MWh)	10th Percentile NOx Emission Rate for fuel Type (lbs/MWh)	Synapse Adjusted NOx Input Rate (lbs/MMBtu)
HUMBOLDT BAY C9	Humboldt Bay: IC 9	Gas	PG&E	North CA	42	5.3	0.253	0.047	0.004
INLAND EMPIRE 1	Inland Empire Energy Center: CS1	Gas	SCE	South Coast	2,712	91.4	0.067	0.047	0.004
INLAND EMPIRE 2	Inland Empire Energy Center: CS2	Gas	SCE	South Coast	2,699	90.6	0.067	0.047	0.004
OTC REPLACE SD1	Generic New CC for L/R Balance	Gas	SDG&E	San Diego	538	18.6	0.069	0.047	0.004
OTC REPLACE SD2	Generic New CC for L/R Balance	Gas	SDG&E	San Diego	544	18.8	0.069	0.047	0.004
SFO AIRPORT GT1	San Francisco Electric Reliability Project	Gas	PG&E	Bay Area	4	1.0	0.516	0.047	0.004
CHOWCHILLA BIO 1	Chowchilla Biomass: AB	Wood	DWR	San Joaquin	85	123.0	2.904	2.960	0.249
EL NIDO BIOMAS 1	El Nido Biomass: AB	Wood	PG&E	San Joaquin	85	122.5	2.891	2.960	0.249
RPSBIO_IID		Wood	IID	Imperial	921	1,362.6	2.960	2.960	0.249
RPSBIO_NP15		Wood	PG&E	Bay Area	515	762.4	2.959	2.960	0.249
RPSBIO_SCE		Wood	SCE	South Coast	282	417.4	2.961	2.960	0.249
RPSBIO_SDGE		Wood	SDG&E	San Diego	287	424.2	2.959	2.960	0.249

Appendix B: Creation of Hybrid Base Case

Background

Synapse Energy Economics required a base case of future build-out and operations in order to estimate the difference in generation and emissions under each of the incremental energy efficiency (EE)/renewable energy (RE) scenarios. The base case was created by hybridizing two AB 32 and 33 percent renewable energy standard (RES)-compliant scenarios for the year 2016 as created by California Energy Commission (Energy Commission) staff for the 2009 Integrated Energy Policy Report (IEPR). The 2009 IEPR utilizes two "bookend" cases to examine high penetrations of RE build-out, one that examines a wind-dominated build-out (known as the "High Wind" scenario) and one that examines a solar-thermal heavy build-out ("High Solar"). Both cases included at least moderate amounts of in-state and out-of-state wind, as well as photovoltaic and solar thermal resources.

Both the High Wind and High Solar pathways represent potentially extreme futures, with a likely AB 32-compliant future emerging somewhere between depending on economic, environmental (siting), licensure, and grid integration considerations. Rather than attempting to find an optimal build-out, Synapse opted to create a Hybrid Base Case representing a more balanced mix of the resources. The hybrid is a 50-50 mix of the high wind and high solar cases. While this scenario does not, and cannot, show how California will meet the RES in future years, it does represent a plausible future.

Creation of Hybrid

Synapse created the Hybrid Case by surveying all inputs to both the High Wind and High Solar scenarios. Synapse recorded which resources were shown to have capacity changes specific to either the High Wind or High Solar scenario. Only units that were determined to exist in the analysis year 2016 were examined. Three categories of generating resource were delineated: units with the same capacities in both scenarios, units that existed in both scenarios with different capacities, and units that only existed in one of the scenarios. Units with the same capacities in both scenarios were left unchanged in the Hybrid Base Case. For units that existed in both scenarios, but differed in nameplate capacity, the average of the two scenario capacities were used for the generating resource. For the units that only existed in one of the two scenarios, a generating unit was created in the Hybrid Base Case with one-half (50 percent) of the nameplate capacity.

Adjustments to Wind and Solar Resources

Wind and solar resources, as modeled in this system, have a "simulated" stochastic load shape, wherein the output of the unit is given explicitly for each hour of the year. For these units, taking the average between the High Wind and High Solar cases, or dividing the resource in half, required extracting 8760 hours of output and manipulating the data. A new index of expected capacity output was then input into the Hybrid Base Case scenario.

A summary of changes between High Wind, High Solar, and Hybrid scenarios can be seen in Table B-1, below. The name plate capacities shown in the table for wind and solar resources represent the maximum capacity of the index—this is the one hour with the highest capacity factor.

Geothermal Resources

New geothermal units were treated differently than wind or solar units. Geothermal units have a static capacity factor. There was only one geothermal unit that needed adjustment in the model; this unit existed in the High Wind scenario, but not in the High Solar scenario. Following the pattern, the name plate capacity of this unit was halved for its inclusion in the Hybrid Base Case. A summary of changes between High Wind, High Solar, and Hybrid can be seen in Table B-1 below.

Table B-1: Summary of Name Plate Capacity Adjustments for Hybrid Base Case

Resource Name	Resource Type	Location	Max Capacity in High Wind Scenario (MW)	Max Capacity in High Solar Scenario (MW)	Max Capacity in Hybrid Scenario (MW)
RPSPV_NP15_REO	Solar PV	PG&E	214	962	589
RPSSol_SCE	Solar Thermal	SCE	N/A	2,319	1,160
RPSPV_SP15_REO	Solar PV	SCE	29	356	193
RPSWT_SDGE_HW	Wind	SDG&E	893	N/A	446
RPSWT_SP15_2HW	Wind	SCE	3,170	N/A	1,585
RPSWT_NBAJ_HW	Wind	NBAJA	651	N/A	326
RPSGeo_IID	Geothermal	IID	1,000	N/A	500
RPSSol_NP15	Solar Thermal	PG&E	N/A	1,450	804
RPSSol_IID	Solar Thermal	IID	N/A	860	464

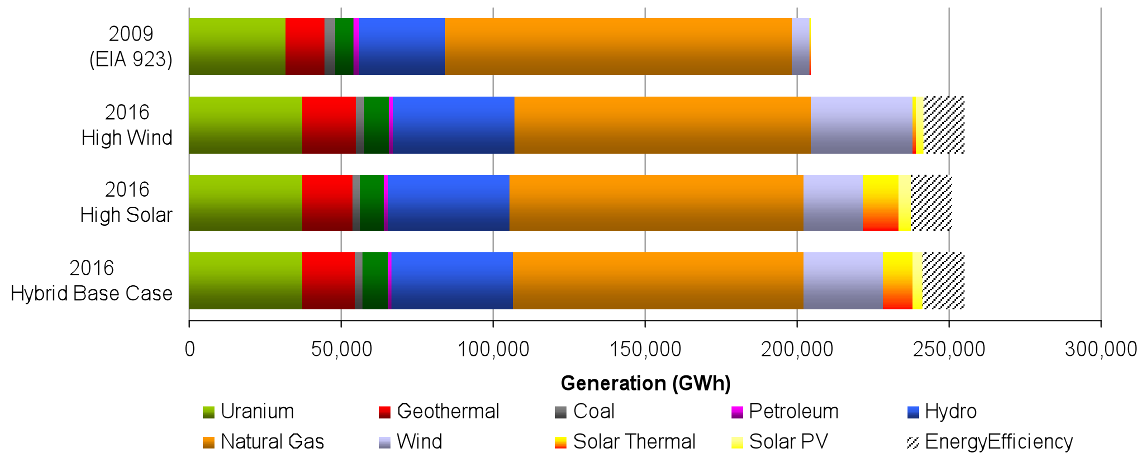
Results

After making the above changes, Synapse ran the model with the Hybrid Renewable Scenario and compared the results to results from both the High Wind and High Solar runs. They Hybrid run successfully hybridized the generation coming from renewable resources, while still being on track for meeting the RES. The High Wind scenario shows 25.9 percent of generation coming from renewable resources, High Solar shows 25.2 percent of generation from renewable sources, and Hybrid Base Case shows generation from renewables slightly higher, at 26.8 percent. The generation from each type of resource is shown below in Table B-2, and illustrated in Figure B-1. Figure B-1 also includes a comparison to generation in 2009 sourced from EIA's Form 923.

Table B-2: Summary of Generation (GWh) from High Wind, High Solar, and Hybrid Scenarios

	Uranium	Geothermal	Coal	Biomass	Petroleum	Hydro	Natural Gas	Wind	Solar Thermal	Solar PV	Energy Efficiency	% from Renewable
2016 High Wind	37,113	17,873	2,694	7,981	1,298	40,098	97,661	33,033	1,350	2,369	13,552	**25.9**
2016 High Solar	37,113	16,576	2,705	7,826	1,312	40,080	96,285	19,777	11,456	4,254	13,552	**25.2**
2016 Hybrid Case	37,113	17,429	2,699	8,006	1,306	40,080	95,374	26,404	9,596	3,312	13,552	**26.8**

Figure B-1: Generation (GWh) in California from Recorded 2009 EIA Data, and 2016 Modeled High Wind, High Solar, and Hybrid Scenarios[28]



[28] Historic and modeled data may not represent the same conditions (such as hydrologic conditions or maintenance outages), and include changes in generation fleet in California.

Appendix C: Detailed Results

This appendix includes tables and graphical charts showing the displacement generation fraction and the displacement rate for NOx, SO_2, and CO_2. The first series of tables and charts show displaced energy and emissions by WECC region (Tables and Figures C-1 through C-4), while the second series shows the same information by California air district (C-5 through C-8). Figures C-9 through C-12 show California displaced energy and emissions by fuel type. In all of the tables below, the first value in the cell is the displaced energy fraction/emissions rate; the second value is an uncertainty range due to random forced outages (in the same units). Negative values are red. Cells in which the random forced outage error exceeds the displaced energy fraction/emissions rate are shaded gray.

Table C-1: Displaced Energy Fraction by WECC Region (MWh/MWh)

Displaced Energy Fraction (%)	SDGE, Wind	SDGE, Solar (PV)	SDGE, EE Baseload	SDGE, EE Peak	SCE, Wind	SCE, Solar (PV)	SCE, EE Baseload	SCE, EE Peak	LADWP, Wind	LADWP, Solar (PV)	LADWP, EE Baseload	LADWP, EE Peak	PG&E, Wind	PG&E, Solar (PV)	PG&E, EE Baseload	PG&E, EE Peak
CA	**20.6%** *9.5%*	**32.3%** *9.4%*	**30.6%** *5.7%*	22.0% 52.7%	**32.3%** *5.7%*	**36.3%** *9.3%*	**35.7%** *5.7%*	**40.8%** *10.6%*	**77.0%** *5.9%*	**80.0%** *9.4%*	**85.6%** *5.7%*	**43.0%** *38.5%*	**55.5%** *13.2%*	**78.3%** *9.7%*	**80.8%** *5.7%*	**91.1%** *10.2%*
NW	**17.2%** *7.2%*	**13.4%** *7.1%*	**11.1%** *4.3%*	6.4% 39.9%	**14.0%** *4.3%*	**12.4%** *7.0%*	**11.4%** *4.3%*	**15.0%** *8.0%*	1.9% 4.5%	4.8% 7.1%	1.4% 4.3%	23.7% 29.1%	8.9% 10.0%	7.0% 7.4%	**7.3%** *4.3%*	-4.4% 7.7%
RM	**16.9%** *3.9%*	**12.3%** *3.9%*	**13.4%** *2.4%*	**39.4%** *21.7%*	**16.7%** *2.4%*	**11.4%** *3.8%*	**11.7%** *2.4%*	**11.7%** *4.4%*	**5.9%** *2.4%*	**4.3%** *3.9%*	**3.1%** *2.4%*	**28.9%** *15.9%*	**14.8%** *5.4%*	**7.3%** *4.0%*	**6.4%** *2.4%*	**8.2%** *4.2%*
SW	**45.2%** *9.6%*	**42.0%** *9.5%*	**44.9%** *5.8%*	31.8% 53.4%	**36.8%** *5.8%*	**39.8%** *9.4%*	**41.1%** *5.8%*	**32.3%** *10.7%*	**15.1%** *6.0%*	**10.8%** *9.5%*	**9.9%** *5.8%*	4.2% 38.9%	**20.6%** *13.3%*	7.2% 9.8%	5.5% 5.8%	5.0% 10.3%

Table C-2: Displaced NO_X Emissions Rate by WECC Region (lbs NO_X/GWh)

Displaced Emissions Rate (lbs NOx/GWh)	SDGE, Wind	SDGE, Solar (PV)	SDGE, EE Baseload	SDGE, EE Peak	SCE, Wind	SCE, Solar (PV)	SCE, EE Baseload	SCE, EE Peak	LADWP, Wind	LADWP, Solar (PV)	LADWP, EE Baseload	LADWP, EE Peak	PG&E, Wind	PG&E, Solar (PV)	PG&E, EE Baseload	PG&E, EE Peak
CA	**55** *16*	**44** *16*	**59** *10*	19 *89*	**57** *10*	**61** *16*	**51** *10*	**88** *18*	**73** *10*	**98** *16*	**79** *10*	**140** *65*	**103** *22*	**124** *16*	**164** *10*	**213** *17*
NW	**184** *172*	120 *170*	**124** *104*	-21 *952*	**171** *104*	96 *168*	79 *104*	33 *191*	17 *107*	28 *170*	-6 *104*	32 *694*	115 *238*	93 *176*	**108** *104*	-93 *183*
RM	**308** *83*	**122** *82*	**182** *50*	322 *460*	**282** *50*	**130** *81*	**156** *50*	**120** *92*	**64** *52*	12 *82*	3 *50*	162 *335*	**324** *115*	**116** *85*	**140** *50*	**112** *88*
SW	**622** *153*	**258** *152*	**438** *92*	-217 *850*	**504** *93*	**304** *150*	**385** *92*	**192** *170*	69 *95*	63 *152*	6 *92*	-394 *620*	**487** *212*	**172** *157*	**196** *92*	-70 *164*
Net Rate	**1,170** *231*	**545** *229*	**803** *139*	103 *1,278*	**1,013** *139*	**592** *225*	**672** *139*	**433** *256*	**223** *143*	200 *228*	82 *139*	-59 *932*	**1,029** *319*	**505** *236*	**608** *139*	162 *246*

Table C-3: Displaced SO_2 Emissions Rate by WECC Region (lbs SO_2/GWh)

Displaced Emissions Rate (lbs SO_2/GWh)	SDGE, Wind	SDGE, Solar (PV)	SDGE, EE Baseload	SDGE, EE Peak	SCE, Wind	SCE, Solar (PV)	SCE, EE Baseload	SCE, EE Peak	LADWP, Wind	LADWP, Solar (PV)	LADWP, EE Baseload	LADWP, EE Peak	PG&E, Wind	PG&E, Solar (PV)	PG&E, EE Baseload	PG&E, EE Peak
CA	**70**	**19**	**31**	-70	**55**	**29**	**31**	-3	**11**	14	-3	-20	**47**	**28**	**61**	**42**
	17	*16*	*10*	*92*	*10*	*16*	*10*	*18*	*10*	*16*	*10*	*67*	*23*	*17*	*10*	*18*
NW	**46**	**34**	**25**	-20	**43**	15	**24**	2	2	3	-6	-6	**36**	17	**31**	-5
	20	*20*	*12*	*113*	*12*	*20*	*12*	*23*	*13*	*20*	*12*	*82*	*28*	*21*	*12*	*22*
RM	**162**	**54**	**68**	50	**157**	**56**	**68**	19	**36**	-9	-3	24	**185**	**64**	**74**	25
	44	*44*	*27*	*246*	*27*	*43*	*27*	*49*	*28*	*44*	*27*	*179*	*61*	*45*	*27*	*47*
SW	**275**	**84**	**155**	-314	**213**	**94**	**132**	33	21	7	-30	**-335**	**185**	52	**95**	-48
	70	*70*	*43*	*391*	*43*	*69*	*43*	*78*	*44*	*70*	*43*	*285*	*98*	*72*	*43*	*75*
Net Rate	**553**	**192**	**279**	**-353**	**469**	**195**	**255**	51	**71**	15	**-42**	**-338**	**454**	**161**	**261**	14
	57	*57*	*35*	*318*	*35*	*56*	*35*	*64*	*36*	*57*	*35*	*231*	*79*	*59*	*35*	*61*

Table C-4: Displaced CO_2 Emissions Rate by WECC Region (t CO_2/MWh)

Displaced Emissions Rate (tCO_2/MWh)	SDGE, Wind	SDGE, Solar (PV)	SDGE, EE Baseload	SDGE, EE Peak	SCE, Wind	SCE, Solar (PV)	SCE, EE Baseload	SCE, EE Peak	LADWP, Wind	LADWP, Solar (PV)	LADWP, EE Baseload	LADWP, EE Peak	PG&E, Wind	PG&E, Solar (PV)	PG&E, EE Baseload	PG&E, EE Peak
CA	**0.07**	**0.12**	**0.13**	0.08	**0.13**	**0.14**	**0.15**	**0.19**	**0.32**	**0.32**	**0.36**	**0.23**	**0.23**	**0.34**	**0.39**	**0.44**
	0.05	*0.05*	*0.03*	*0.26*	*0.03*	*0.05*	*0.03*	*0.05*	*0.03*	*0.05*	*0.03*	*0.19*	*0.06*	*0.05*	*0.03*	*0.05*
NW	**0.11**	**0.08**	**0.07**	0.03	**0.09**	0.07	**0.06**	0.07	0.01	0.03	0.01	0.11	0.06	0.05	**0.06**	-0.05
	0.08	*0.08*	*0.05*	*0.43*	*0.05*	*0.07*	*0.05*	*0.09*	*0.05*	*0.08*	*0.05*	*0.31*	*0.11*	*0.08*	*0.05*	*0.08*
RM	**0.13**	**0.07**	**0.09**	**0.23**	**0.12**	**0.07**	**0.07**	**0.07**	**0.04**	0.02	0.01	**0.16**	**0.12**	**0.05**	**0.05**	**0.06**
	0.03	*0.02*	*0.02*	*0.14*	*0.02*	*0.02*	*0.02*	*0.03*	*0.02*	*0.02*	*0.02*	*0.10*	*0.03*	*0.03*	*0.02*	*0.03*
SW	**0.27**	**0.17**	**0.23**	-0.07	**0.21**	**0.17**	**0.20**	**0.13**	0.03	0.04	0.02	-0.17	**0.15**	0.04	**0.04**	-0.05
	0.07	*0.07*	*0.04*	*0.40*	*0.04*	*0.07*	*0.04*	*0.08*	*0.04*	*0.07*	*0.04*	*0.29*	*0.10*	*0.07*	*0.04*	*0.08*
Net Rate	**0.57**	**0.44**	**0.52**	0.27	**0.55**	**0.45**	**0.49**	**0.47**	**0.39**	**0.40**	**0.39**	**0.32**	**0.56**	**0.47**	**0.54**	**0.41**
	0.07	*0.07*	*0.04*	*0.38*	*0.04*	*0.07*	*0.04*	*0.08*	*0.04*	*0.07*	*0.04*	*0.28*	*0.10*	*0.07*	*0.04*	*0.07*

Figure C-1: Displaced Energy Fraction by WECC Region and Fuel Type

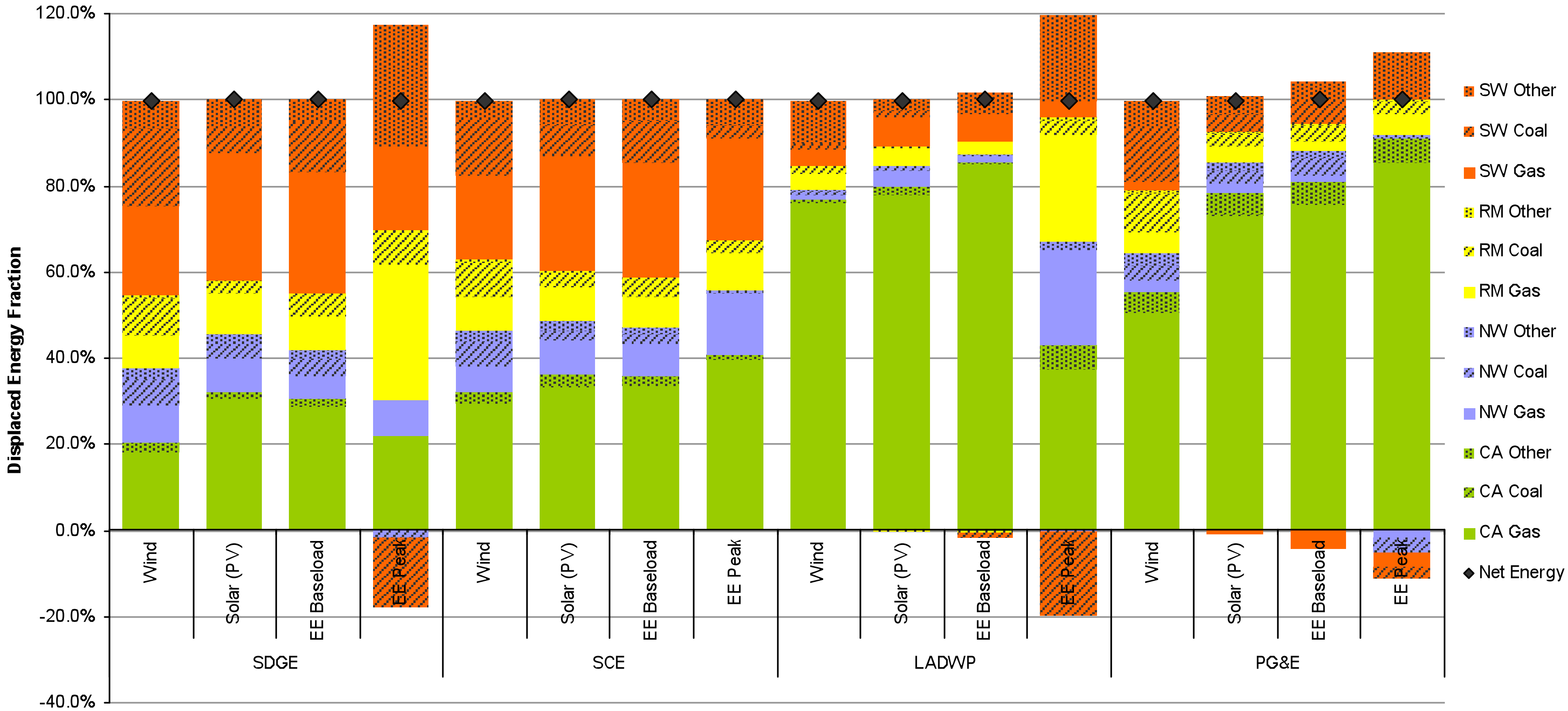


Figure C-2: Displaced lbs of NO_X per GWh of Energy Displaced, by WECC Region and Fuel Type

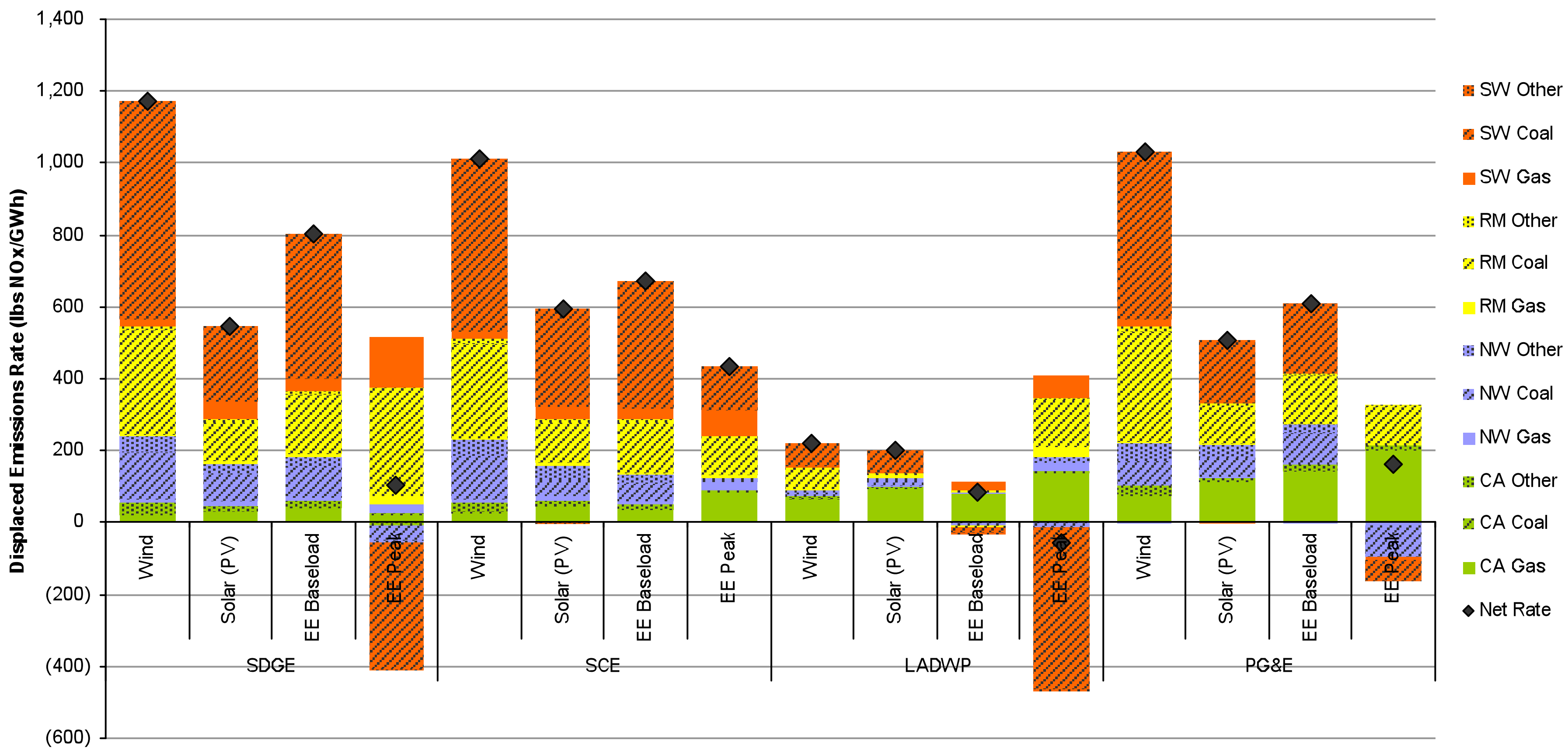


Figure C-3: Displaced lbs of SO_2 per GWh of Energy Displaced, by WECC Region and Fuel Type

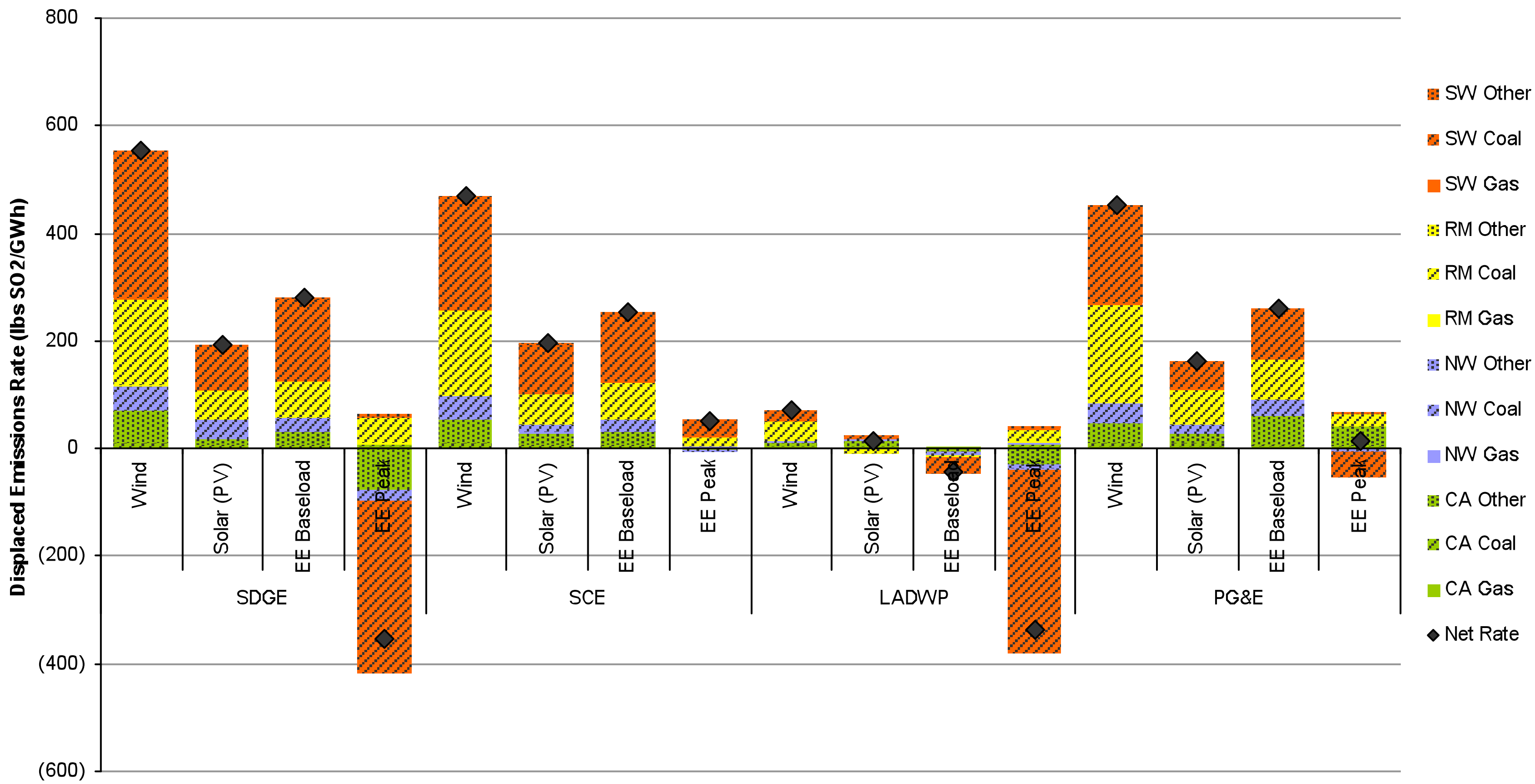


Figure C-4: Displaced Tons of CO_2 per MWh of Energy Displaced, by WECC Region and Fuel Type

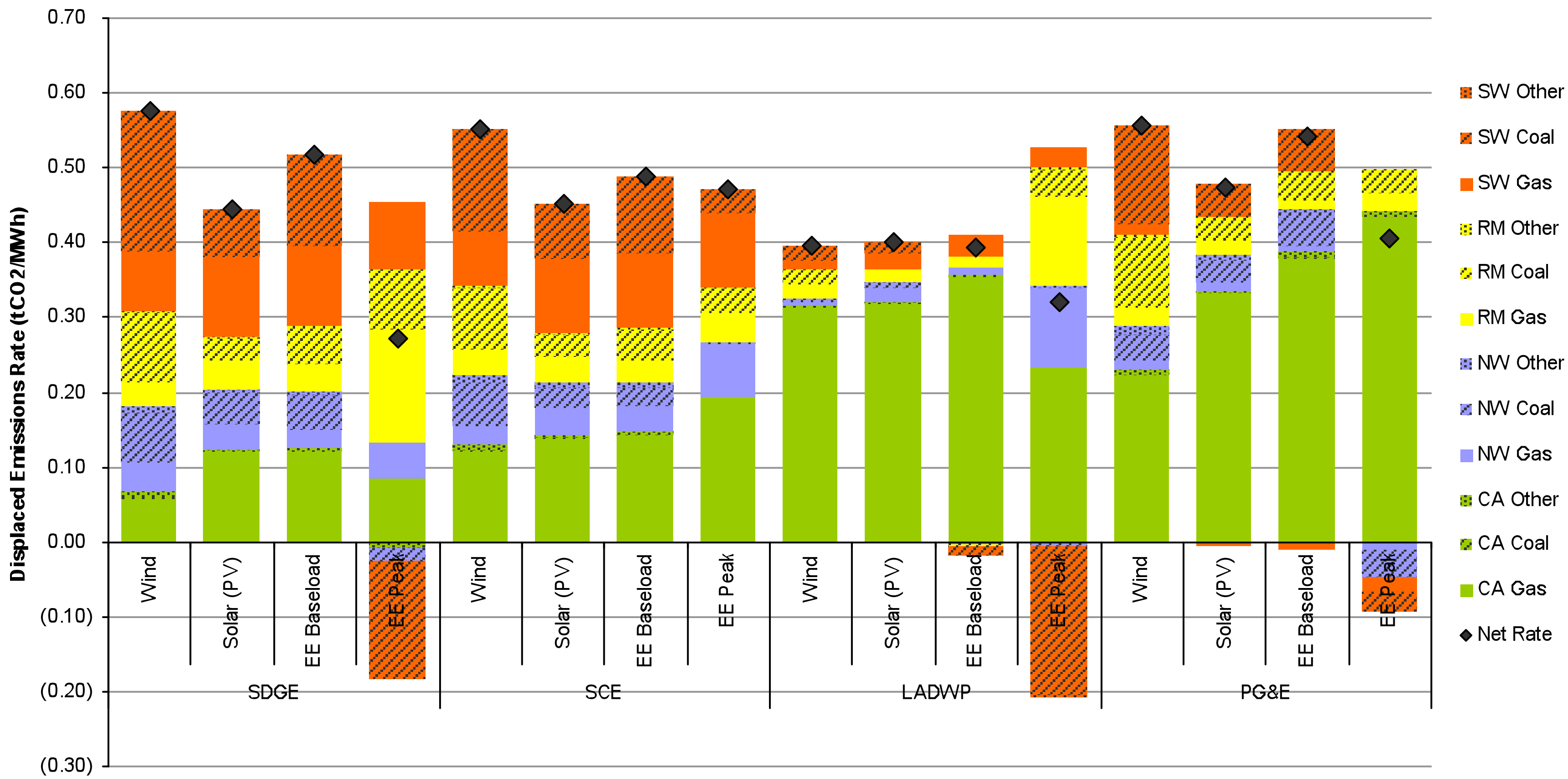


Table C-5: Displaced Energy Fraction by Air District (MWh / MWh)

Displaced Energy Fraction by Air District	SDGE, Wind	SDGE, Solar (PV)	SDGE, EE Baseload	SDGE, EE Peak	SCE, Wind	SCE, Solar (PV)	SCE, EE Baseload	SCE, EE Peak	LADWP, Wind	LADWP, Solar (PV)	LADWP, EE Baseload	LADWP, EE Peak	PG&E, Wind	PG&E, Solar (PV)	PG&E, EE Baseload	PG&E, EE Peak
North CA	**0.4%** *0.3%*	0.3% *0.3%*	**0.4%** *0.2%*	-1.0% *1.8%*	**0.4%** *0.2%*	**0.5%** *0.3%*	**0.4%** *0.2%*	0.1% *0.4%*	0.1% *0.2%*	0.2% *0.3%*	-0.1% *0.2%*	-0.3% *1.3%*	**1.6%** *0.5%*	**2.3%** *0.3%*	**2.0%** *0.2%*	**2.7%** *0.3%*
Bay North	2.2% *2.7%*	**3.4%** *2.7%*	**3.8%** *1.7%*	-6.6% *15.2%*	**3.6%** *1.7%*	**3.1%** *2.7%*	**6.2%** *1.7%*	-0.3% *3.0%*	0.3% *1.7%*	-0.6% *2.7%*	-0.7% *1.7%*	-1.5% *11.1%*	**10.7%** *3.8%*	**11.9%** *2.8%*	**13.0%** *1.7%*	**7.6%** *2.9%*
Bay Area	**7.2%** *3.0%*	**8.8%** *3.0%*	**6.8%** *1.8%*	7.0% *16.8%*	**8.8%** *1.8%*	**9.4%** *3.0%*	**7.3%** *1.8%*	-1.5% *3.4%*	**2.5%** *1.9%*	2.7% *3.0%*	-0.6% *1.8%*	-9.5% *12.3%*	**17.9%** *4.2%*	**26.1%** *3.1%*	**23.6%** *1.8%*	**29.3%** *3.2%*
Sierra North	**2.4%** *1.3%*	0.1% *1.3%*	**2.4%** *0.8%*	6.8% *7.3%*	**2.9%** *0.8%*	1.1% *1.3%*	**2.2%** *0.8%*	0.1% *1.5%*	**1.0%** *0.8%*	1.1% *1.3%*	-0.3% *0.8%*	1.2% *5.3%*	**4.9%** *1.8%*	**3.8%** *1.3%*	**7.1%** *0.8%*	**5.1%** *1.4%*
Sierra South	**0.0%** *0.0%*	**0.0%** *0.0%*	**0.0%** *0.0%*	0.0% *0.0%*	**0.0%** *0.0%*	**0.0%** *0.0%*	**0.0%** *0.0%*	0.0% *0.0%*	**0.0%** *0.0%*	0.0% *0.0%*	0.0% *0.0%*	0.0% *0.0%*	**0.0%** *0.0%*	**0.0%** *0.0%*	**0.0%** *0.0%*	0.0% *0.0%*
Sacramento	**1.3%** *0.7%*	**1.9%** *0.7%*	**1.1%** *0.4%*	-0.7% *4.1%*	**1.6%** *0.4%*	**2.1%** *0.7%*	**1.4%** *0.4%*	0.1% *0.8%*	0.2% *0.5%*	0.7% *0.7%*	0.1% *0.4%*	-0.8% *3.0%*	**2.8%** *1.0%*	**4.8%** *0.8%*	**3.3%** *0.4%*	**6.6%** *0.8%*
San Joaquin	1.4% *1.6%*	**3.5%** *1.6%*	**2.9%** *0.9%*	-1.4% *8.7%*	**2.9%** *0.9%*	**5.3%** *1.5%*	**3.4%** *0.9%*	**3.4%** *1.7%*	**1.1%** *1.0%*	**2.0%** *1.6%*	0.5% *0.9%*	1.2% *6.3%*	**7.7%** *2.2%*	**10.8%** *1.6%*	**10.4%** *0.9%*	**17.7%** *1.7%*
Central Coast	**-1.5%** *1.5%*	**-1.8%** *1.5%*	0.6% *0.9%*	**-23.9%** *8.2%*	**2.7%** *0.9%*	-0.1% *1.4%*	**2.2%** *0.9%*	**-4.2%** *1.6%*	**-1.6%** *0.9%*	**-2.9%** *1.5%*	**-4.3%** *0.9%*	**-14.5%** *6.0%*	**5.8%** *2.1%*	**11.0%** *1.5%*	**14.2%** *0.9%*	**15.6%** *1.6%*
Desert Region	0.6% *1.5%*	1.0% *1.5%*	0.8% *0.9%*	6.9% *8.3%*	0.6% *0.9%*	1.1% *1.5%*	**1.0%** *0.9%*	**3.9%** *1.7%*	0.5% *0.9%*	0.9% *1.5%*	0.7% *0.9%*	4.0% *6.1%*	0.0% *2.1%*	0.8% *1.5%*	0.4% *0.9%*	0.8% *1.6%*
South Coast	2.7% *4.3%*	**7.7%** *4.2%*	**6.1%** *2.6%*	15.8% *23.6%*	**4.8%** *2.6%*	**8.0%** *4.2%*	**6.3%** *2.6%*	**28.8%** *4.7%*	**71.5%** *2.6%*	**70.6%** *4.2%*	**89.3%** *2.6%*	**50.4%** *17.2%*	-0.5% *5.9%*	1.3% *4.3%*	0.0% *2.6%*	0.4% *4.5%*
San Diego	**2.9%** *0.9%*	**5.4%** *0.9%*	**5.0%** *0.5%*	**12.5%** *4.9%*	**2.3%** *0.5%*	**3.5%** *0.9%*	**3.0%** *0.5%*	**5.7%** *1.0%*	**0.6%** *0.5%*	**1.7%** *0.9%*	**1.0%** *0.5%*	**5.9%** *3.6%*	-0.9% *1.2%*	-0.1% *0.9%*	**-1.3%** *0.5%*	-0.9% *0.9%*
Imperial	**1.1%** *0.3%*	**0.8%** *0.3%*	**0.9%** *0.2%*	1.6% *1.8%*	**1.1%** *0.2%*	**0.6%** *0.3%*	**0.8%** *0.2%*	**1.8%** *0.4%*	0.1% *0.2%*	0.2% *0.3%*	0.0% *0.2%*	1.3% *1.3%*	0.4% *0.5%*	**-0.5%** *0.3%*	0.0% *0.2%*	**-0.6%** *0.3%*

Table C-6: Displaced NO_X Emissions Rate by Air District (lbs NO_X/GWh)

Displaced lbs of NOx per GWh of Energy Displaced, by Air District	SDGE, Wind	SDGE, Solar (PV)	SDGE, EE Baseload	SDGE, EE Peak	SCE, Wind	SCE, Solar (PV)	SCE, EE Baseload	SCE, EE Peak	LADWP, Wind	LADWP, Solar (PV)	LADWP, EE Baseload	LADWP, EE Peak	PG&E, Wind	PG&E, Solar (PV)	PG&E, EE Baseload	PG&E, EE Peak
North CA	1.0	0.0	1.5	**-15.7**	1.4	1.2	0.3	-0.8	-0.6	0.1	-0.4	-6.4	**7.7**	**5.6**	**12.8**	**22.2**
	2.7	*2.7*	*1.6*	*15.0*	*1.6*	*2.6*	*1.6*	*3.0*	*1.7*	*2.7*	*1.6*	*10.9*	*3.7*	*2.8*	*1.6*	*2.9*
Bay North	0.5	**1.1**	**1.0**	-1.9	**1.0**	0.7	**1.8**	0.1	0.1	-0.2	-0.1	0.9	**3.3**	**3.6**	**4.0**	**2.5**
	0.7	*0.7*	*0.4*	*4.1*	*0.4*	*0.7*	*0.4*	*0.8*	*0.5*	*0.7*	*0.4*	*3.0*	*1.0*	*0.8*	*0.4*	*0.8*
Bay Area	**11.6**	7.2	**11.4**	-19.5	**13.1**	**13.6**	**8.6**	-6.7	2.1	1.7	-2.5	-26.1	**27.3**	**39.5**	**47.2**	**69.9**
	9.1	*9.0*	*5.5*	*50.2*	*5.5*	*8.9*	*5.5*	*10.1*	*5.6*	*9.0*	*5.5*	*36.6*	*12.5*	*9.3*	*5.5*	*9.7*
Sierra North	**4.4**	-0.8	**4.1**	-10.7	**2.9**	**3.1**	**2.9**	-2.6	0.8	1.2	-0.7	-9.2	**11.3**	**12.9**	**20.5**	**29.4**
	2.7	*2.7*	*1.6*	*15.0*	*1.6*	*2.7*	*1.6*	*3.0*	*1.7*	*2.7*	*1.6*	*11.0*	*3.8*	*2.8*	*1.6*	*2.9*
Sierra South	**0.7**	**0.4**	**0.5**	0.0	**1.0**	**0.8**	**0.7**	-0.1	0.1	-0.1	-0.1	-0.9	**0.8**	**0.8**	**0.5**	-0.1
	0.3	*0.3*	*0.2*	*1.8*	*0.2*	*0.3*	*0.2*	*0.4*	*0.2*	*0.3*	*0.2*	*1.3*	*0.4*	*0.3*	*0.2*	*0.3*
Sacramento	-0.6	**-1.5**	0.2	**-11.3**	0.2	-0.7	0.4	**-1.5**	-0.2	-0.4	-0.2	**-4.6**	0.9	**2.4**	**4.4**	**8.5**
	0.9	*0.9*	*0.6*	*5.1*	*0.6*	*0.9*	*0.6*	*1.0*	*0.6*	*0.9*	*0.6*	*3.7*	*1.3*	*0.9*	*0.6*	*1.0*
San Joaquin	**7.5**	2.8	**7.2**	**-46.4**	**5.4**	**11.8**	**5.2**	0.5	1.5	3.2	-0.1	-10.1	**22.9**	**30.6**	**43.6**	**75.9**
	7.4	*7.3*	*4.4*	*40.8*	*4.4*	*7.2*	*4.4*	*8.2*	*4.6*	*7.3*	*4.4*	*29.7*	*10.2*	*7.5*	*4.4*	*7.8*
Central Coast	**0.7**	**3.1**	**2.7**	**8.2**	**3.6**	**2.4**	**3.6**	**9.8**	**1.5**	**1.7**	0.3	**10.5**	**6.6**	**12.5**	**11.8**	**8.8**
	0.6	*0.6*	*0.4*	*3.5*	*0.4*	*0.6*	*0.4*	*0.7*	*0.4*	*0.6*	*0.4*	*2.5*	*0.9*	*0.6*	*0.4*	*0.7*
Desert Region	**5.3**	**4.3**	**3.3**	16.3	**4.9**	**4.9**	**4.1**	**8.7**	**2.7**	**3.8**	**2.9**	**15.1**	4.5	**4.9**	**2.8**	1.1
	3.7	*3.6*	*2.2*	*20.4*	*2.2*	*3.6*	*2.2*	*4.1*	*2.3*	*3.6*	*2.2*	*14.8*	*5.1*	*3.8*	*2.2*	*3.9*
South Coast	**7.0**	**7.9**	**9.6**	18.2	**8.6**	**8.2**	**9.6**	**39.0**	**57.0**	**76.3**	**74.6**	**107.1**	3.0	0.6	2.9	**-8.2**
	6.0	*5.9*	*3.6*	*33.0*	*3.6*	*5.8*	*3.6*	*6.6*	*3.7*	*5.9*	*3.6*	*24.1*	*8.3*	*6.1*	*3.6*	*6.4*
San Diego	**6.6**	**9.3**	**9.8**	**45.8**	**4.3**	**5.4**	**4.2**	**26.4**	**4.3**	4.0	**4.0**	**41.2**	3.1	2.3	1.0	-2.4
	4.4	*4.3*	*2.6*	*24.3*	*2.7*	*4.3*	*2.6*	*4.9*	*2.7*	*4.3*	*2.6*	*17.7*	*6.1*	*4.5*	*2.6*	*4.7*
Imperial	**8.4**	**5.6**	**6.4**	**18.8**	**8.6**	**7.4**	**6.6**	**9.8**	**3.0**	**2.5**	**2.1**	**19.7**	**8.0**	**5.7**	**5.6**	**2.5**
	1.2	*1.2*	*0.7*	*6.9*	*0.8*	*1.2*	*0.7*	*1.4*	*0.8*	*1.2*	*0.7*	*5.0*	*1.7*	*1.3*	*0.7*	*1.3*

Table C-7: Displaced SO_2 Emissions Rate by Air District (lbs NO_X/GWh)

Displaced lbs of SO_2 per GWh of Energy Displaced, by Air District	SDGE, Wind	SDGE, Solar (PV)	SDGE, EE Baseload	SDGE, EE Peak	SCE, Wind	SCE, Solar (PV)	SCE, EE Baseload	SCE, EE Peak	LADWP, Wind	LADWP, Solar (PV)	LADWP, EE Baseload	LADWP, EE Peak	PG&E, Wind	PG&E, Solar (PV)	PG&E, EE Baseload	PG&E, EE Peak
North CA	0.0 *0.0*	0.0 *0.0*	0.0 *0.0*	0.0 *0.0*	0.0 *0.0*	0.0 *0.0*	0.0 *0.0*	0.0 *0.0*	0.0 *0.0*	0.0 *0.0*	0.0 *0.0*	0.0 *0.0*	0.0 *0.0*	0.0 *0.0*	0.0 *0.0*	0.0 *0.0*
Bay North	0.1 *0.4*	0.2 *0.4*	**0.5** *0.3*	0.6 *2.5*	**0.3** *0.3*	0.1 *0.4*	**0.6** *0.3*	-0.1 *0.5*	0.1 *0.3*	0.1 *0.4*	0.0 *0.3*	0.9 *1.8*	**1.1** *0.6*	**0.6** *0.5*	**1.3** *0.3*	**0.7** *0.5*
Bay Area	**9.4** *5.2*	0.4 *5.2*	**4.8** *3.1*	-21.3 *28.8*	**6.5** *3.1*	2.9 *5.1*	**3.3** *3.1*	-1.3 *5.8*	3.0 *3.2*	2.6 *5.1*	0.7 *3.1*	-7.3 *21.0*	**9.9** *7.2*	**8.3** *5.3*	**17.6** *3.1*	**32.3** *5.6*
Sierra North	0.1 *0.1*	0.0 *0.1*	0.0 *0.1*	0.0 *0.6*	0.1 *0.1*	0.0 *0.1*	0.0 *0.1*	0.0 *0.1*	0.1 *0.1*	0.1 *0.1*	**-0.1** *0.1*	0.0 *0.5*	0.0 *0.2*	0.0 *0.1*	**0.1** *0.1*	**0.2** *0.1*
Sierra South	0.0 *0.1*	0.0 *0.1*	0.0 *0.1*	0.0 *0.5*	0.0 *0.1*	0.0 *0.1*	0.0 *0.1*	0.0 *0.1*	0.0 *0.1*	0.0 *0.1*	0.0 *0.1*	0.0 *0.4*	0.0 *0.1*	0.0 *0.1*	0.0 *0.1*	0.0 *0.1*
Sacramento	-0.1 *0.1*	0.0 *0.1*	**-0.1** *0.1*	0.0 *0.8*	0.0 *0.1*	-0.1 *0.1*	0.0 *0.1*	0.0 *0.2*	0.0 *0.1*	-0.1 *0.1*	0.0 *0.1*	0.0 *0.6*	0.0 *0.2*	0.1 *0.1*	0.0 *0.1*	**0.2** *0.1*
San Joaquin	**5.8** *3.1*	2.0 *3.0*	**2.3** *1.8*	-3.1 *16.9*	**3.1** *1.8*	1.9 *3.0*	1.4 *1.8*	1.0 *3.4*	**1.9** *1.9*	1.5 *3.0*	1.6 *1.8*	0.9 *12.3*	**4.2** *4.2*	**3.7** *3.1*	**6.4** *1.8*	**12.0** *3.3*
Central Coast	**0.2** *0.2*	**0.2** *0.2*	**0.3** *0.1*	-0.6 *1.0*	**0.4** *0.1*	**0.7** *0.2*	**0.3** *0.1*	**-0.3** *0.2*	0.1 *0.1*	-0.1 *0.2*	**-0.1** *0.1*	0.0 *0.7*	**0.9** *0.3*	**1.2** *0.2*	**1.0** *0.1*	**1.1** *0.2*
Desert Region	**8.6** *1.9*	**4.2** *1.9*	**3.9** *1.1*	5.0 *10.4*	**7.7** *1.1*	**4.8** *1.8*	**4.4** *1.1*	0.5 *2.1*	**1.4** *1.2*	0.8 *1.9*	0.1 *1.1*	2.3 *7.6*	**7.2** *2.6*	**4.2** *1.9*	**4.2** *1.1*	1.3 *2.0*
South Coast	**45.5** *21.4*	10.8 *21.3*	**18.9** *12.9*	-55.2 *118.8*	**37.5** *13.0*	18.5 *21.0*	**20.1** *12.9*	-5.5 *23.8*	4.6 *13.3*	8.1 *21.2*	-5.7 *12.9*	-21.0 *86.6*	23.7 *29.7*	10.3 *21.9*	**30.5** *12.9*	-6.6 *22.9*
San Diego	0.3 *0.3*	**0.4** *0.3*	**0.4** *0.2*	**3.1** *1.9*	0.1 *0.2*	0.2 *0.3*	**0.3** *0.2*	**1.1** *0.4*	0.0 *0.2*	**0.4** *0.3*	0.1 *0.2*	**1.8** *1.4*	0.3 *0.5*	0.1 *0.4*	0.1 *0.2*	0.4 *0.4*
Imperial	0.0 *0.1*	0.1 *0.1*	0.1 *0.1*	0.6 *0.7*	0.0 *0.1*	0.1 *0.1*	0.1 *0.1*	**0.4** *0.1*	0.0 *0.1*	0.1 *0.1*	0.1 *0.1*	0.5 *0.5*	0.0 *0.2*	0.0 *0.1*	0.0 *0.1*	0.0 *0.1*

Table C-8: Displaced CO_2 Emissions Rate by Air District (t CO_2/MWh)

Displaced tons of CO_2 per MWh of Energy Displaced, by Air District	SDGE, Wind	SDGE, Solar (PV)	SDGE, EE Baseload	SDGE, EE Peak	SCE, Wind	SCE, Solar (PV)	SCE, EE Baseload	SCE, EE Peak	LADWP, Wind	LADWP, Solar (PV)	LADWP, EE Baseload	LADWP, EE Peak	PG&E, Wind	PG&E, Solar (PV)	PG&E, EE Baseload	PG&E, EE Peak
North CA	**0.00**	**0.00**	**0.00**	-0.01	**0.00**	**0.00**	**0.00**	0.00	0.00	0.00	0.00	0.00	**0.01**	**0.01**	**0.01**	**0.02**
	0.00	*0.00*	*0.00*	*0.01*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.01*	*0.00*	*0.00*	*0.00*	*0.00*
Bay North	0.01	**0.01**	**0.01**	-0.03	**0.01**	0.01	**0.03**	0.00	0.00	0.00	0.00	0.00	**0.04**	**0.05**	**0.06**	**0.03**
	0.01	*0.01*	*0.01*	*0.07*	*0.01*	*0.01*	*0.01*	*0.01*	*0.01*	*0.01*	*0.01*	*0.05*	*0.02*	*0.01*	*0.01*	*0.01*
Bay Area	**0.03**	**0.03**	**0.03**	0.02	**0.03**	**0.04**	**0.03**	-0.02	**0.01**	0.01	-0.01	**-0.07**	**0.08**	**0.12**	**0.12**	**0.15**
	0.02	*0.02*	*0.01*	*0.09*	*0.01*	*0.02*	*0.01*	*0.02*	*0.01*	*0.02*	*0.01*	*0.06*	*0.02*	*0.02*	*0.01*	*0.02*
Sierra North	**0.01**	0.00	**0.01**	0.03	**0.01**	0.01	**0.01**	0.00	**0.00**	0.01	0.00	0.00	**0.02**	**0.02**	**0.03**	**0.02**
	0.01	*0.01*	*0.00*	*0.03*	*0.00*	*0.01*	*0.00*	*0.01*	*0.00*	*0.01*	*0.00*	*0.02*	*0.01*	*0.01*	*0.00*	*0.01*
Sierra South	**0.00**	**0.00**	**0.00**	0.00	**0.00**	**0.00**	**0.00**	0.00	**0.00**	0.00	0.00	0.00	**0.00**	**0.00**	**0.00**	0.00
	0.00	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*
Sacramento	**0.00**	**0.01**	**0.00**	-0.01	**0.01**	**0.01**	**0.01**	0.00	0.00	0.00	0.00	-0.01	**0.01**	**0.02**	**0.01**	**0.03**
	0.00	*0.00*	*0.00*	*0.02*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.01*	*0.00*	*0.00*	*0.00*	*0.00*
San Joaquin	0.01	**0.02**	**0.02**	-0.02	**0.01**	**0.03**	**0.02**	**0.01**	**0.01**	**0.01**	0.00	0.00	**0.05**	**0.06**	**0.06**	**0.11**
	0.01	*0.01*	*0.00*	*0.04*	*0.00*	*0.01*	*0.00*	*0.01*	*0.00*	*0.01*	*0.00*	*0.03*	*0.01*	*0.01*	*0.00*	*0.01*
Central Coast	**-0.01**	**-0.01**	0.00	**-0.14**	**0.01**	0.00	**0.01**	**-0.02**	**-0.01**	**-0.02**	**-0.02**	**-0.08**	**0.02**	**0.05**	**0.08**	**0.08**
	0.01	*0.01*	*0.01*	*0.06*	*0.01*	*0.01*	*0.01*	*0.01*	*0.01*	*0.01*	*0.01*	*0.04*	*0.01*	*0.01*	*0.01*	*0.01*
Desert Region	0.00	0.01	**0.00**	**0.04**	0.00	0.01	**0.01**	**0.02**	0.00	0.00	0.00	0.02	0.00	0.01	0.00	0.00
	0.01	*0.01*	*0.00*	*0.04*	*0.00*	*0.01*	*0.00*	*0.01*	*0.00*	*0.01*	*0.00*	*0.03*	*0.01*	*0.01*	*0.00*	*0.01*
South Coast	0.01	**0.03**	**0.03**	0.09	**0.02**	**0.03**	**0.03**	**0.16**	**0.30**	**0.30**	**0.38**	**0.31**	0.00	0.01	0.00	0.00
	0.03	*0.02*	*0.02*	*0.14*	*0.02*	*0.02*	*0.02*	*0.03*	*0.02*	*0.02*	*0.02*	*0.10*	*0.03*	*0.03*	*0.02*	*0.03*
San Diego	**0.01**	**0.02**	**0.02**	**0.08**	**0.01**	**0.01**	**0.01**	**0.03**	**0.00**	**0.01**	**0.01**	**0.05**	0.00	0.00	**0.00**	0.00
	0.01	*0.01*	*0.00*	*0.03*	*0.00*	*0.01*	*0.00*	*0.01*	*0.00*	*0.01*	*0.00*	*0.02*	*0.01*	*0.01*	*0.00*	*0.01*
Imperial	**0.00**	**0.00**	**0.00**	0.01	**0.00**	**0.00**	**0.00**	**0.01**	0.00	0.00	0.00	**0.01**	0.00	0.00	**0.00**	0.00
	0.00	*0.00*	*0.00*	*0.01*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.01*	*0.00*	*0.00*	*0.00*	*0.00*

Figure C-5: Displaced Energy Fraction by Air District (MWh per MWh)

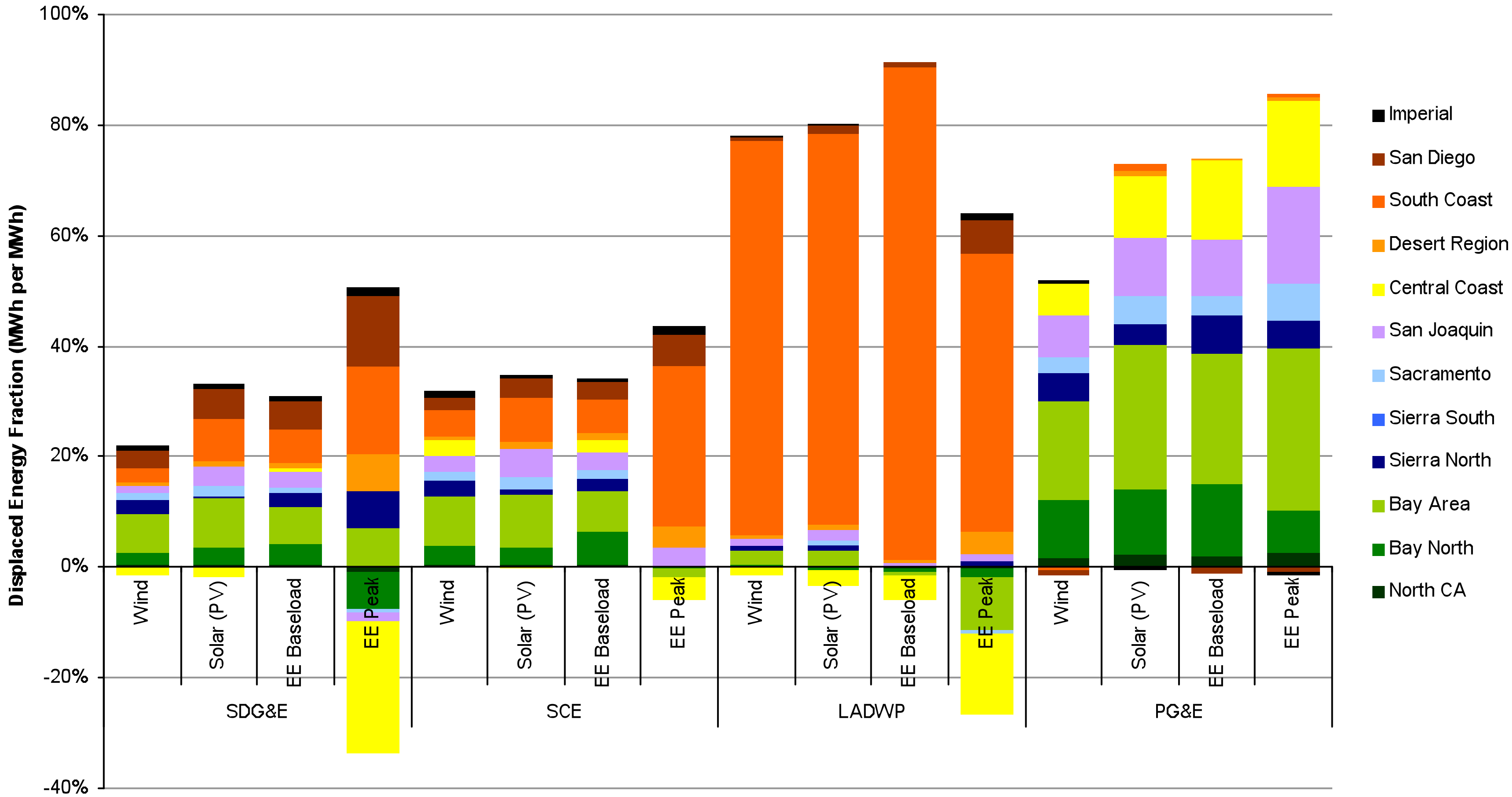


Figure C-6: Displaced lbs of NO_X per GWh of Energy Displaced, by Air District

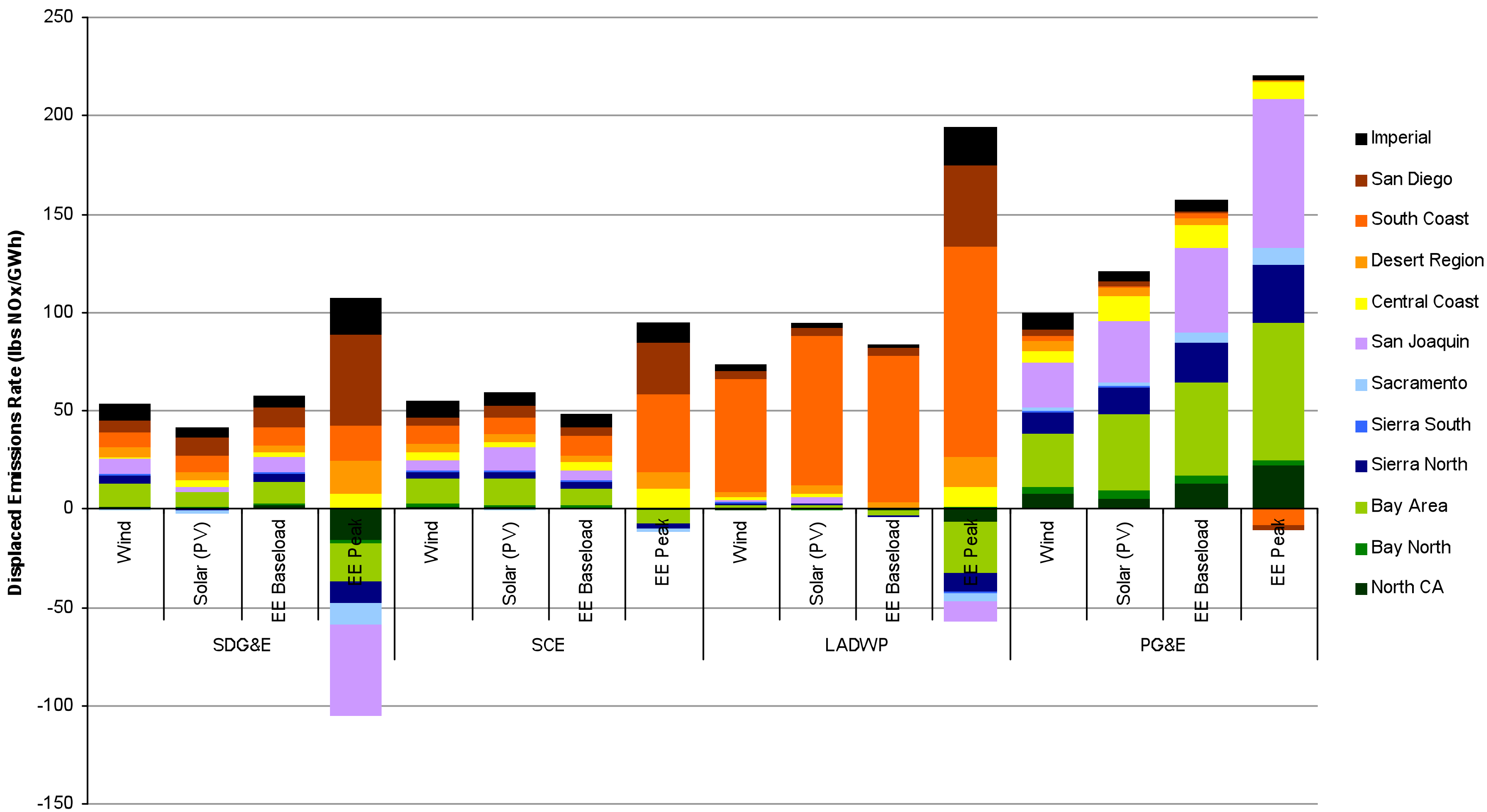


Figure C-7: Displaced lbs of SO_2 per GWh of Energy Displaced, by Air District

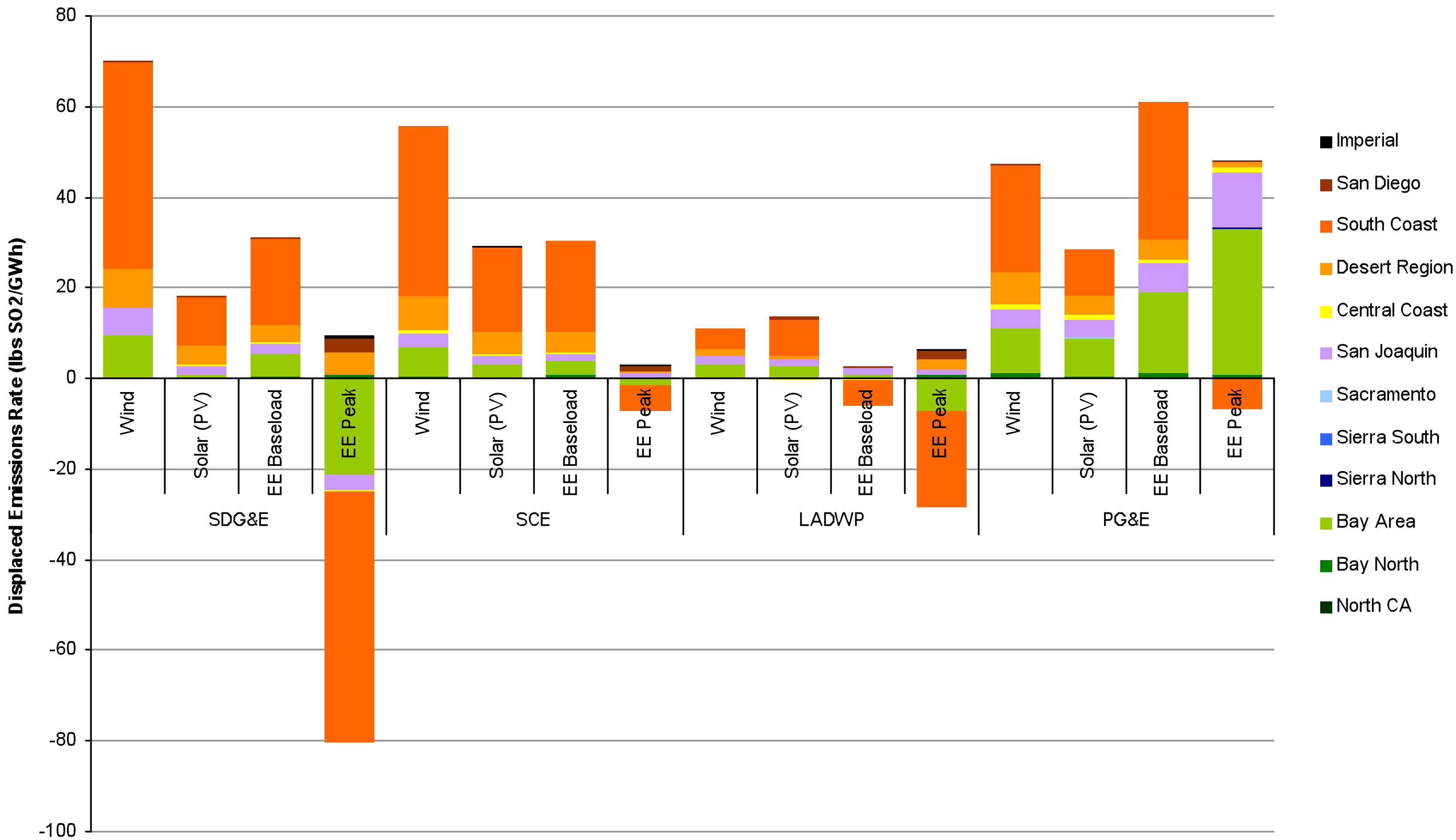


Figure C-8: Displaced Tons of CO_2 per MWh of Energy Displaced, by Air District

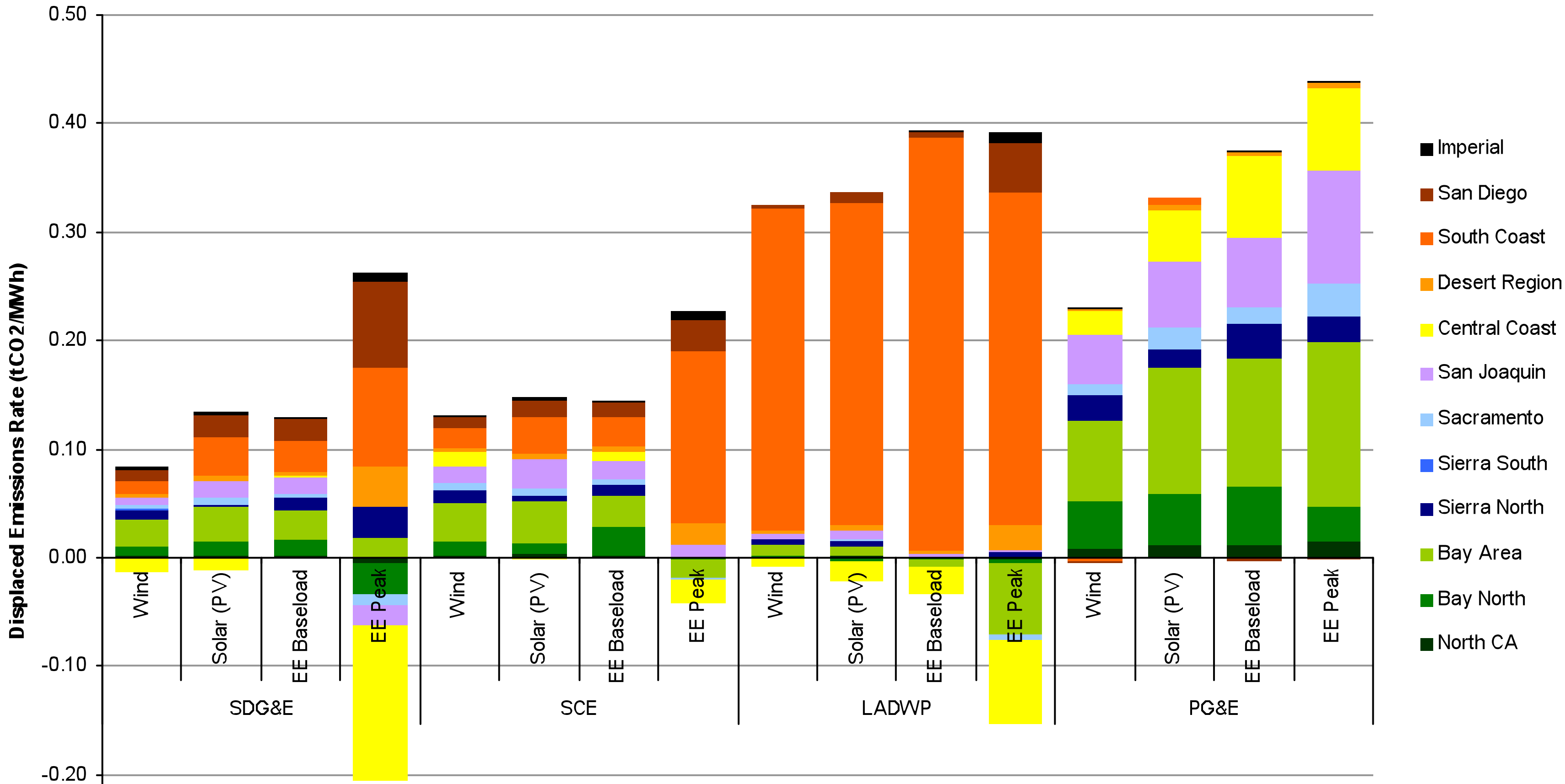


Figure C-9: Displaced Energy Fraction, by Fuel in California

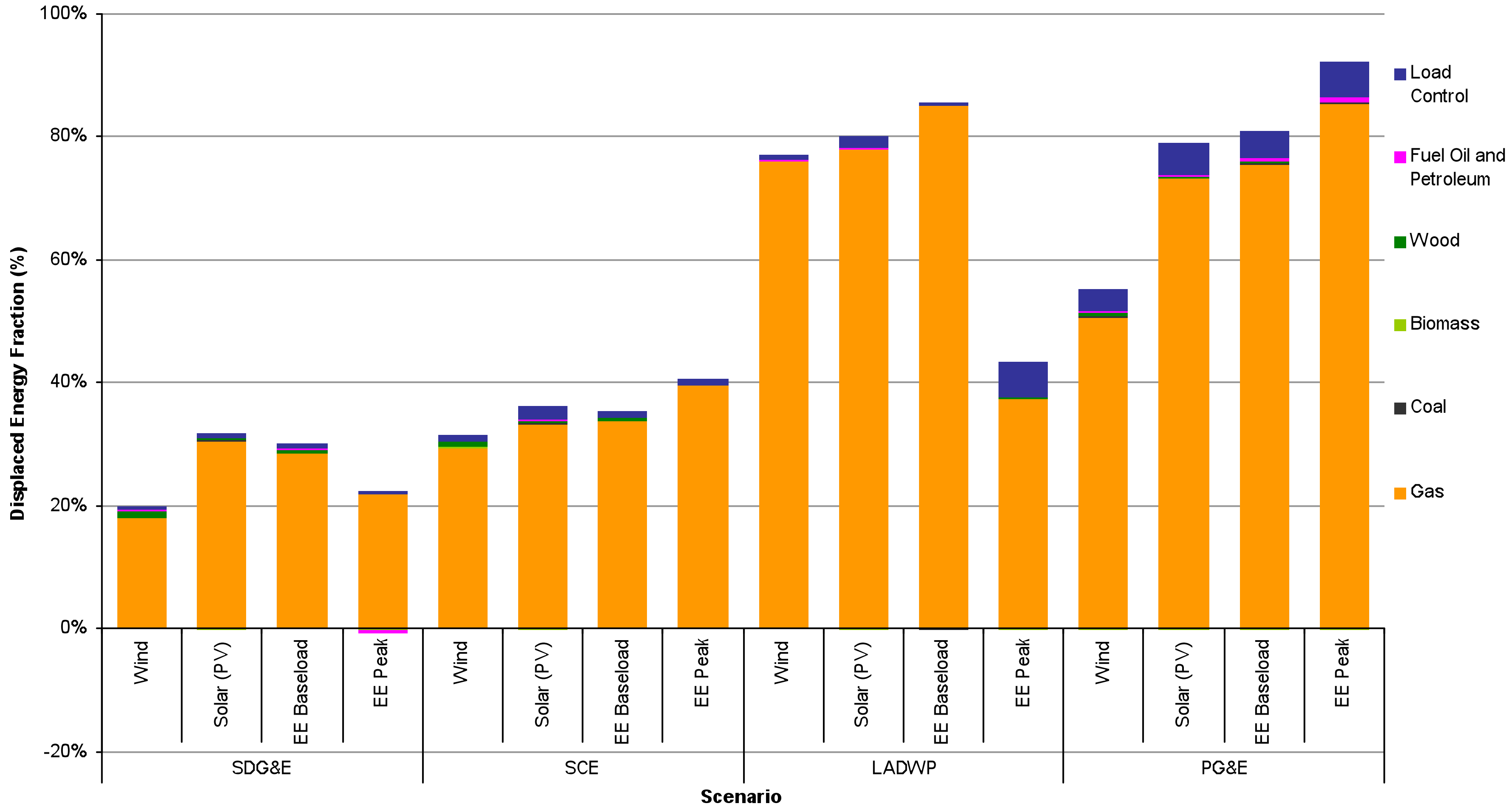


Figure C-10: Displaced lbs of NO_X per GWh of Energy Displaced, by Fuel in CA

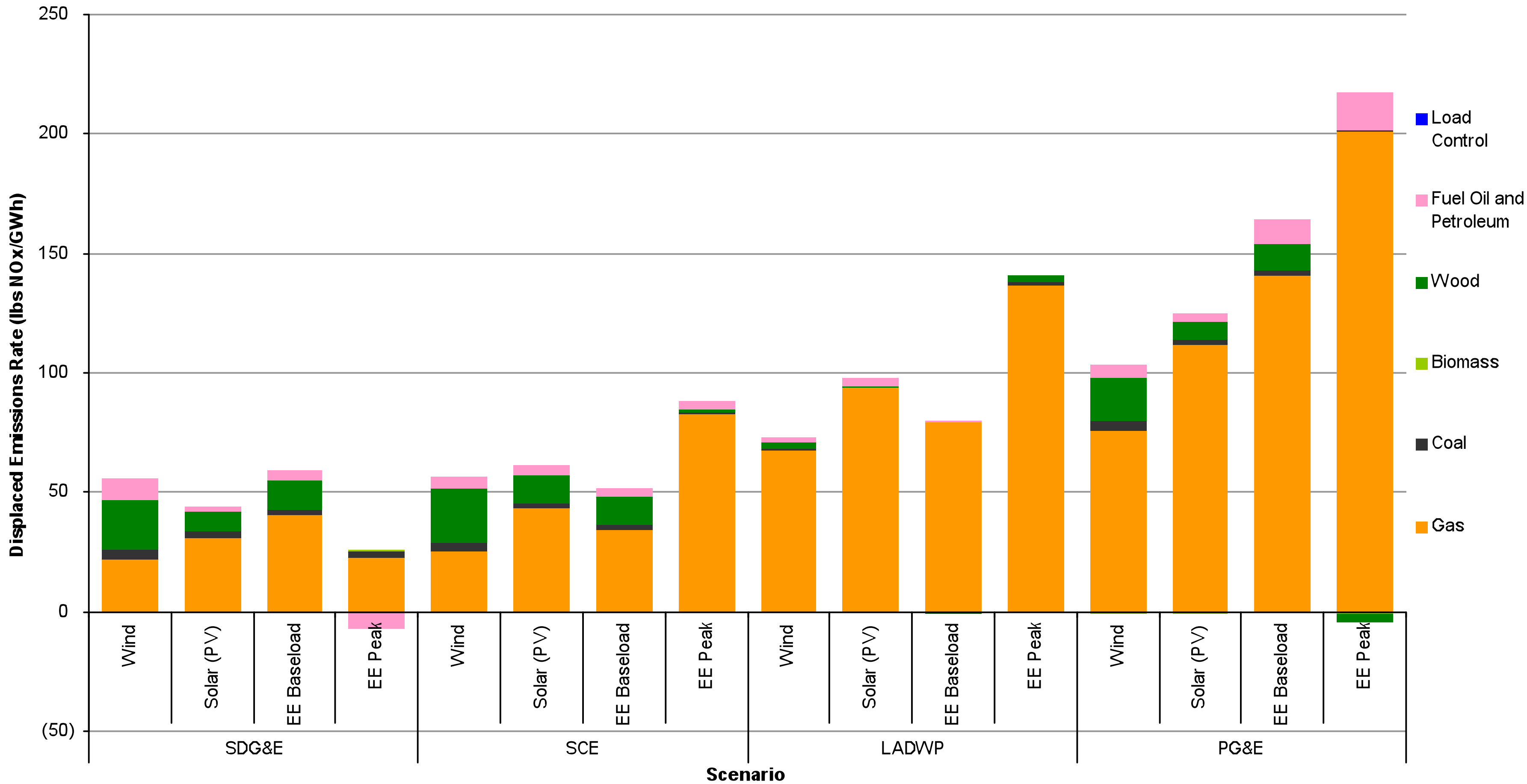


Figure C-11: Displaced lbs of SO_2 per MWh of Energy Displaced, by Fuel in CA

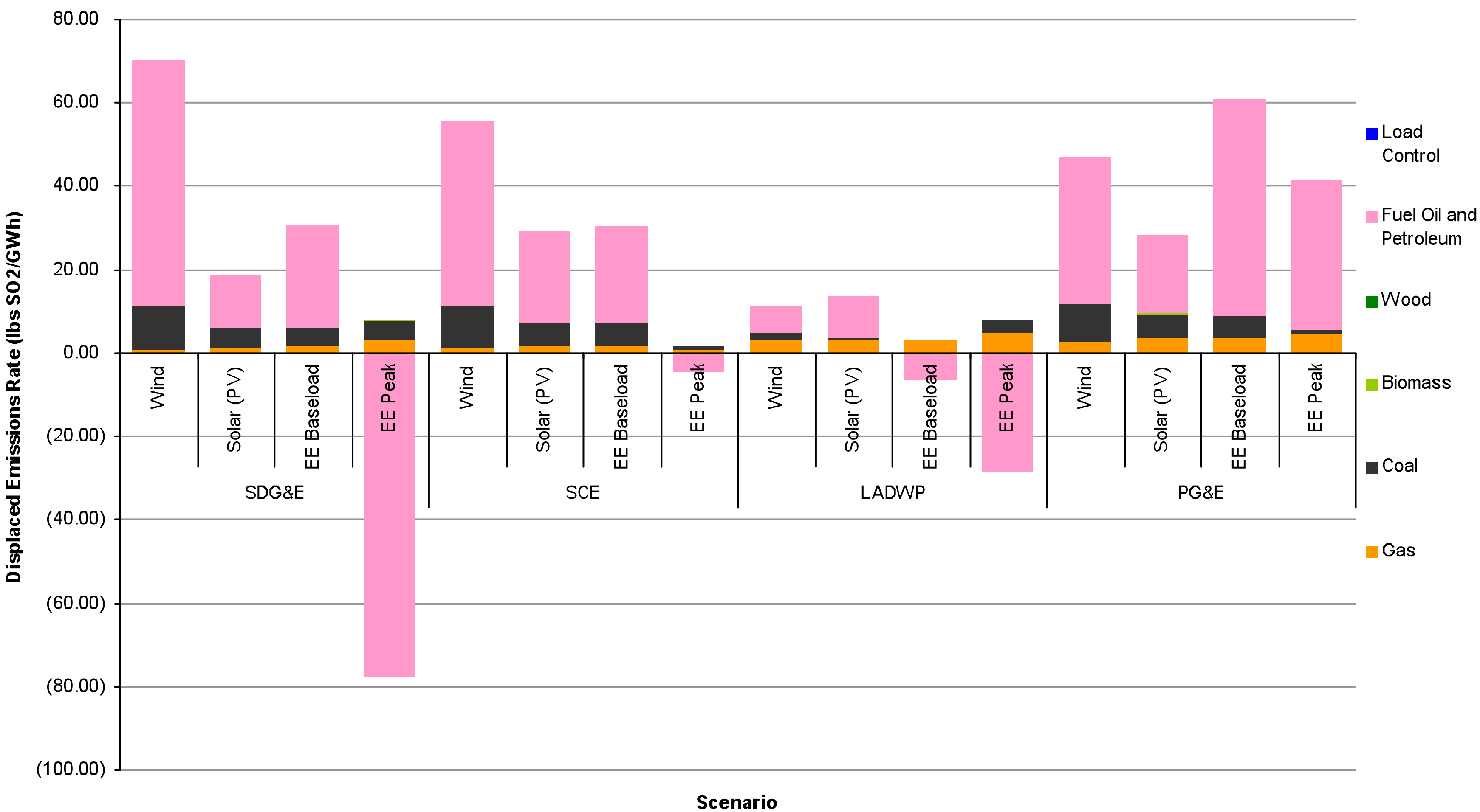


Figure C-12: Displaced Tons of CO_2 per MWh of Energy Displaced, by Fuel in CA