The Value of Transmission in Electricity Markets: Evidence from a Nuclear Power Plant Closure

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November 2014

Abstract

In this paper, we exploit the abrupt closure of the San Onofre Nuclear Generating Station to estimate the value of electricity transmission. Following the plant's closure in February 2012, we find that as much as 75% of lost generation during high demand hours was met locally. Although lower-cost production was available elsewhere, transmission constraints and other physical limitations of the grid severely limited the ability of other producers to sell into the southern California market. These constraints also made it potentially more profitable for certain plants to exercise market power, and we find evidence consistent with one company acting non-competitively.

Key Words: Electricity Markets, Transmission Constraints, Nuclear Power, Carbon Emissions
JEL: L51, L94, Q41, Q54

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1 Introduction

Geographic integration of markets improves the allocation of production across firms, reduces price dispersion, and increases consumer and producer surplus. These benefits are particularly important in electricity markets because unlike most other goods, electricity cannot be cost-effectively stored. Supply must meet demand at all times, or the frequency in the grid will fall outside of a narrow tolerance band, causing blackouts. In addition, electricity demand is highly variable and highly inelastic. As a result, the market clears mostly on the supply side, with production ramping up and down to meet demand. Geographic integration helps smooth this volatility, reducing the frequency and severity of price spikes and better allocating production across plants.

Connecting electricity markets requires substantial investments in transmission lines and other infrastructure. In the United States, total investments in electricity transmission reach almost $15 billion annually (Edison Electric Institute, 2014). This spending is expected to increase over the next several years as additional transmission capacity is needed to help integrate wind, solar, and other intermittent generation technologies. These are large, long-lived projects, so making the right level of investment in the right locations is extremely important. Reliable estimates of the value of transmission are critical if these investments are to made cost-effectively.

Quantifying the value of transmission is challenging. Investments in transmission capacity are endogenous responses to changes in market conditions, making it hard to construct a credible counterfactual for what would have happened without these investments. In addition, investments are anticipated years in advance, so before-and-after comparisons can be difficult to interpret. Moreover, the engineering and economic models that are used in the industry rely on strong simplifying assumptions that are difficult to verify empirically (Barmack et al., 2006).

In this paper, we use evidence from a nuclear power plant closure to quantify the value of transmission in the California electricity market. Between 2005 and 2011, the San Onofre Nuclear Generating Station (SONGS) generated an average of 16 million megawatt hours of electricity annually, making it the second largest electric generating facility in California. During this period, SONGS generated enough electricity to meet the needs of 2.3 million California households[1] – about 8% of all electricity generated in the state. Moreover, SONGS was even more valuable than these numbers suggest because of its location between Los Angeles and San Diego, two enormous demand centers. Although there is transmission that connects Southern California to the rest of the state, the capacity is limited, implying that a

[1] U.S. DOE/EIA "Electric Sales, Revenue, and Average Price," November 2013, Tables T1 and T2. California households used an average of 6.9 megawatt hours in 2012.

large part of demand must be met locally. SONGS was closed abruptly and permanently in February 2012, when workers discovered problems with the plant's steam generators. Because of the plant's size and prominence, the closure provides a valuable opportunity to learn about the value of electricity transmission capacity.

Even in a world without transmission constraints or market power, closing a large generation source will impact the price of wholesale electricity. Like other nuclear power plants, SONGS produced electricity at very low marginal cost. Consequently, the plant was always near the top of the "merit-order," operating around the clock and providing a consistent source of electricity. When SONGS was closed, this generation had to be made up for by operating other, more expensive generating resources. We use rich micro-data from a variety of sources and an econometric model to identify those marginal resources that would be expected to increase production. Overall, we find that bringing these additional power plants online cost around $63,000 each hour.

In addition to these merit-order effects, the closure caused transmission constraints to bind, essentially segmenting the California market. Prior to the closure, transmission capacity between Northern and Southern California was usually sufficient, so that wholesale prices equalized in the two regions during the vast majority of hours. Although SONGS was occasionally shut down temporarily for refueling or maintenance, plant managers were careful to schedule these outages during the winter, when demand is low. Beginning with the permanent closure in 2012, we document a substantial divergence in prices between Northern and Southern California.

This binding transmission constraint and other physical constraints of the grid meant that it was not possible to meet all of the lost output from SONGS using the lowest cost available generating resources. We find that during low demand hours, the change in generation follows closely the merit order, with about half of the increased generation coming from Southern California and the other half coming from Northern California. During high demand hours, however, we find significant "out-of-merit" effects: higher cost generating units coming online more than we would have expected. In high demand hours in 2012, we find that as much as 75% of the lost generation was met by plants located in Southern California. On average, these constraints increased generation costs by an average of $4,500 per hour, implying that the total cost of additional natural gas generation was almost $68,000 per hour in the twelve months following the closure.

Distinguishing between merit-order and out-of-merit effects requires a credible counterfactual for what the pattern of generation would have been without transmission constraints. The empirical strategy that we adopt in the paper is to exploit the fact that prior to the closure, transmission constraints were rarely binding in the California market. We use data from

this pre-period to describe flexibly the relationship between unit-level generation and system-wide demand. These estimates are used to predict what operating behavior would have been after the SONGS closure were there no transmission constraints. We then compare generating units' actual behavior with this counterfactual to measure out-of-merit effects. This approach affords several advantages over a simple before and after comparison. Most importantly, we are able to account for concurrent changes to hydroelectric resources, renewables, demand, and other market conditions – all of which would confound a before and after comparison.

Our results provide a detailed account of economic and environmental outcomes. We find that the SONGS closure increased the cost of electricity generation in California by about $350 million during the first twelve months. This is a large change, equivalent to a 13 percent increase in total in-state generation costs, yet it went almost completely unnoticed because of a large offsetting decrease in natural gas prices that occurred in 2012. In fact, a simple before-and-after calculation would have erroneously concluded that the SONGS closure actually *decreased* electricity prices. The SONGS closure also had important implications for the environment, increasing carbon dioxide emissions by 9 million tons in the twelve months following the closure. To put this in some perspective, this is the equivalent of putting 2 million additional cars on the road, and implies a social cost of emissions of almost $320 million per year.[2]

Of this $350 million in increased private generation costs during the first twelve months, we attribute $40 million to transmission constraints and other physical limitations of the grid. Over a ten-year time horizon with a 6.6% discount rate, this implies that the value of additional transmission capacity is $300 million. As we discuss, this is substantially higher than the cost of infrastructure projects that would relieve some of the constraints. The California Independent System Operator evidently agrees, and since 2013 has been increasing transmission capacity and making other investments aimed at better integrating northern San Diego county with the rest of the California market.

We are also able to determine which individual plants changed their behavior the most after the SONGS closure. Because of the transmission constraints, the largest out-of-merit increases are at Southern plants, and the largest out-of-merit decreases are at Northern plants. Surprisingly, we also find large out-of-merit decreases during high demand hours at two Southern plants: Alamitos and Redondo, both owned by the same company. This was unexpected but, as it turns out, not coincidental. The Federal Energy Regulatory Commission recently alleged market manipulation at these plants over the period 2010 to 2012, for which JP Morgan paid fines of over $400 million. The fact that the results clearly identified these two plants

[2] According to U.S. DOE/EIA Annual Energy Review, September 2012, Table 2.8 "Motor Vehicle Mileage, Fuel Consumption, and Fuel Economy", light-duty vehicles with a short wheelbase use an average of 453 gallons of gasoline annually. For each gallon of gasoline, 19.6 pounds of carbon dioxide are emitted.

suggests that our approach may serve as a useful diagnostic tool. Although a large out-of-merit effect does not prove that a plant is exercising market power, it is a good indicator of unusual behavior.

Our paper adds to a small but growing literature on the value of geographic integration in electricity markets (Mansur and White, 2012; Wolak, 2012; Birge et al., 2013; Ryan, 2013). Economists have long written about the importance of transmission constraints, but previous studies have either used stylized theoretical models (Cardell, Hitt and Hogan, 1997; Joskow and Tirole, 2000), or Cournot simulations (Borenstein, Bushnell and Stoft, 2000; Ryan, 2013), rather than econometric analysis. Our methodology is novel, because it quantifies the value of transmission without requiring strong assumptions about the firms' objective function or an explicit representation of the physical constraints of the electric grid. While our estimates are not directly applicable to other markets, we see broad potential for applying this method elsewhere. Our approach relies entirely on publicly-available data, so it would be relatively straightforward to perform similar analyses in other markets, both for quantifying the impacts of large changes in generation and transmission infrastructure, and for detecting unusual changes in firm behavior.[3]

2 Background

2.1 Electricity Markets

In the United States, electricity generation in 2012 came from coal (37%); natural gas (30%); nuclear (19%); hydro (7%); and wind, solar and other renewables (5%).[4] This mix of technologies reflects cost, flexibility, and environmental objectives. Wind, solar, and other renewables have near zero marginal cost, so they occupy the top of the merit order. Next in the order is nuclear, which has a low marginal cost relative to fossil fuel plants. Fossil fuel plants follow, with coal tending to be cheaper than natural gas. Depending on fuel prices, however, there may be some highly-efficient natural gas plants with lower marginal cost than particularly inefficient coal plants.

Regulation of electricity markets varies across states and has changed over time. Under the classic regulatory model still used in many states today, electric utilities receive exclusive rights to provide electricity within given geographic areas and charge rates set by cost-of-service

[3]Such large changes are not uncommon. For instance, the current California drought has led to hydroelectric generation levels in 2014 that are over one million MWh per month lower than the 2005-2013 averages, a drop roughly equal to the loss in generation from SONGS. As another example, Germany has closed 6 of 17 nuclear power plants (6.3 total gigawatts) since the Fukushima accident in March 2011 (Grossi, Heim and Waterson, 2014).

[4]Table 7.2a "Electricity Net Generation: Total (All Sectors)" in EIA (2013b).

regulation. These vertically-integrated utilities typically perform all the activities required to supply electricity: generating electricity, operating the transmission and distribution networks, and providing retail services.

In part as a response to the limitations of cost-of-service regulation, several states began to deregulate their electricity markets beginning in the late 1990s. In most states, the deregulation process separated generation from transmission and distribution. Whereas most economists believe generation is potentially competitive, transmission and distribution are natural monopolies. Wholesale electricity markets were established in several different regions, and regulators required utilities to sell all or part of their existing electric generating portfolios to independent power producers.

Deregulation has resulted in gains in operating efficiency (Fabrizio, Rose and Wolfram, 2007; Davis and Wolfram, 2012), but it has also introduced opportunities for generation companies to exercise market power (Borenstein and Bushnell, 1999; Borenstein, Bushnell and Wolak, 2002; Bushnell, Mansur and Saravia, 2008; Hortacsu and Puller, 2008). As with any market, the scope for individual firms to affect prices depends on the size of the market and the number of firms. With electricity, however, the lack of cost-effective storage and inelastic short-run demand makes the market particularly susceptible to market power, even when market concentration is relatively low.

Economists have also long recognized the key role of transmission capacity in deregulated electricity markets (Cardell, Hitt and Hogan, 1997; Bushnell, 1999; Borenstein, Bushnell and Stoft, 2000; Joskow and Tirole, 2000; Wolak, 2012; Birge et al., 2013; Ryan, 2013). When transmission lines are unconstrained, electricity moves between markets at virtually no cost, prices are equated across markets, and the effective size of the market is large. However, when transmission capacity is limited, the effective size of the local market shrinks, potentially making it more profitable for producers to withhold generation. There is also related work on how centralized markets can increase the effective size of the market. Mansur and White (2012) document how the expansion of a wholesale electricity market from the Eastern United States to the Midwest led to a substantial increase in efficiency, equating prices across regions and improving allocative efficiency.

2.2 The California Landscape

California was part of this initial wave of electricity deregulation. California's wholesale electricity market was launched in April 1998, with all three major investor owned utilities required to buy and sell electricity through this new market. Around the same time, the utilities were required to sell nearly all of their natural gas power plants to independent power producers. By the end of the 1990s, independent power producers controlled more than 30

percent of the electricity generating capacity in the state.

For the first two years after the market opened, wholesale prices varied widely across hours, but average monthly prices stayed below $50 per megawatt hour. Then in 2000 the nascent market was put to the test. The year was unusually dry, leading to below average hydro generation, and the summer was unusually hot, increasing demand. Starting in June 2000, wholesale prices spiked and for the next several months average monthly prices exceeded $100 per megawatt hour. The prices were devastating to the utilities, who were required to buy electricity in the wholesale market and then sell it to customers at lower, regulated rates. California's largest utility, Pacific Gas and Electric, declared bankruptcy in 2001, and the state eventually intervened and suspended the market.

Most economic analyses of this period have concluded that generation companies exercised market power that pushed prices considerably higher than they would have gone due to market fundamentals (Borenstein, Bushnell and Wolak, 2002; Joskow and Kahn, 2002; Puller, 2007). Borenstein, Bushnell and Wolak (2002), for example, finds that about half of the increase in electricity expenditures during summer 2000 was due to market power. These studies are innovative in the broader industrial organization literature because they illustrate how under tight market conditions firms can exercise unilateral market power even with a small market share. This was noted in the many studies of the crisis, and also presaged by Borenstein and Bushnell (1999) using a Cournot model to simulate the California market.

The California market today looks considerably different. First, a much higher fraction of electricity is sold using long-term contracts. This reduces the incentive for producers to withhold generation in the spot market because they cannot influence the price of the output already committed through contracts (Allaz and Vila, 1993). Second, short-run demand for electricity in California is more elastic than it was in 2000. Although the vast majority of residential and commercial customers continue to face time-invariant retail prices, a growing number of California industrial customers face more dynamic rates. Third, the state's renewable portfolio standard and other state and federal policies have led to substantial investments in wind, solar, and other renewables. This has increased total generation capacity during a period in which demand has been relatively flat.

Overall the California generation portfolio is substantially less carbon intensive than the rest of the United States, with more emphasis on natural gas, hydro, and renewables. By far the largest source of generation is natural gas, with 44% of total generation in 2011. The second largest source is hydro, accounting for 21% of generation. The two nuclear plants, San Onofre and Diablo Canyon, each contributed approximately 9% of total generation in 2011. Finally, geothermal, wind, solar, and other renewables account for about 13% of total generation. Details are provided in the Online Appendix.

2.3 The San Onofre Nuclear Generating Station

San Onofre Nuclear Generation Station (SONGS) is a retired two-reactor, 2,150 megawatt nuclear power plant, operated by Southern California Edison (SCE).[5] SONGS was valuable to the California market not just because it generated a large amount of generation, but also because of its prime location. Located in the Northwest corner of San Diego County, SONGS provided electricity in the highly-populated corridor between Los Angeles and San Diego, where there are few other large power plants.

Trouble for SONGS started on January 31, 2012 when operators detected a small leak inside one of the steam generators. The reactor with the leak was shut down immediately. At the time this occurred, the other reactor had already been shut down for three weeks for a routine refueling outage. Although it was not known at the time, neither reactor would ever operate again. On investigation, it was discovered that thousands of tubes in the steam generators in both units were showing premature wear. This was followed by months of testing and, eventually, a proposal to the Nuclear Regulatory Commission (NRC) to restart one of the units at reduced power level. An additional eight months passed without a decision from the NRC. Meanwhile, policymakers grew concerned that without SONGS, the grid would face "additional operational challenges in the Los Angeles Basin and San Diego areas" (CEC 2012), relating to the possibility of insufficient summer capacity and the possibility of transmission constraints (CAISO 2012; NERC 2012).

Facing uncertainty about the NRC ruling, and continued costs of maintaining SONGS in a state of readiness, SCE made the decision in June 2013 to permanently retire the facility. "SONGS has served this region for over 40 years," explained Ted Craver, Chairman and CEO, "but we have concluded that the continuing uncertainty about when or if SONGS might return to service was not good for our customers, our investors, or the need to plan for our region's long-term electricity needs." (Southern California Edison, 2013).[6]

The SONGS closure was abrupt, permanent, and unexpected, making it a valuable opportunity to learn about behavior in electricity markets.[7] It is worth noting that there is some precedent for studying changes in market behavior during changes in nuclear plant operations. In particular, Wolfram (1999) instruments for wholesale electricity prices using available nuclear capacity, exploiting the large quasi-random changes in electricity supply due

[5] SCE is also the majority owner (78%). The other owners are San Diego Gas & Electric (20%) and the city of Riverside (2%).

[6] SONGS is one of three U.S. nuclear power plants to close over the last decade. Crystal River and Kewaunee were both officially closed in 2013. Additionally, Vermont Yankee is scheduled to close in 2014. For a survey of the broader challenges faced by nuclear power see Davis (2012).

[7] In contrast, investment in new capacity is both expected and endogenous to market activity. Even many outages at existing transmission are endogenous, as grid operators stress the system. Moreover, they are typically short-lived.

to unplanned outages. Our study is different in that we focus on a permanent shock rather than temporary outages, but the identifying variation is similar. Allcott, Collard-Wexler and O'Connell (2014) also use exogenous changes in supply, in their case variation in hydro generation.

The SONGS closure is especially interesting for an empirical analysis because whereas most large plant closures are anticipated months or even years in advance, the SONGS closure was abrupt and unexpected. This sharpens the impact and interpretation considerably as it provided little opportunity for the anticipatory investments in generation and transmission that typically accompany infrastructure openings and closings. In addition, SONGS is of particular interest because it operated in a deregulated electricity market. In states where generation companies are regulated using cost-of-service regulation there is less scope (and less incentive) for generating units to exercise market power in response to changes in market conditions.

Finally, the SONGS closure is noteworthy because it evokes parallels with the California electricity crisis. The year 2012 was similar to 2000 in that both years were unusually dry, resulting in low levels of hydro generation. Removing an enormous generation source like SONGS, particularly during a bad year for hydroelectric generation, might have been expected to create tight supply conditions like in 2000. As it turns out, however, market prices and other outcomes in 2012 were very different from the experience in 2000. We think that comparing the behavior of the market in 2012 to 2000 can yield insights, both about firm behavior and market design.

3 Data

For this analysis we compiled data from a variety of different sources including the U.S. Department of Energy's Energy Information Administration (EIA), the California Independent System Operator (CAISO), and the U.S. Environmental Protection Agency (EPA). As we mention in the introduction, a strength of our analysis is that it relies entirely on publicly-available data.

3.1 Generation Data from EIA

We first assembled a dataset of annual plant-level electricity generation from the EIA's *Power Plant Operation Report* (EIA-923). This is a required survey for all U.S. electric generating facilities with more than one megawatt of capacity. The advantage of these data is that they are comprehensive, including not only large fossil-fuel generating units, but also smaller and less frequently operated units, as well as hydroelectric facilities, solar and wind plants, and

nuclear plants. Most California plants complete the survey only once per year, so we perform all analyses of the EIA-923 data at the annual level, relying on the other datasets listed below for within-year comparisons. These data also contain information on plant characteristics, including operator name, fuel type, and some details about the generation technology. We supplement these characteristics with additional information (county, capacity, and vintage) from another Department of Energy dataset, the *Annual Electric Generator Report* (EIA-860).

Table 1 describes California electricity generation in 2011 and 2012. SONGS was closed on January 31, 2012, so the columns can be approximately interpreted as before and after the SONGS closure. Panel A reports average monthly generation by fuel type. Nuclear generation decreased by 1.5 million megawatt hours monthly; this matches the drop in generation expected given the SONGS hourly capacity of 2,150 MW. The table also shows, however, that 2012 was a relatively bad year for hydroelectric power, with a decrease of 1.3 million megawatt hours monthly. Thus the year-on-year decrease in hydroelectric generation is almost as large as the lost generation from SONGS. Offsetting these decreases, natural gas generation in California increased by 2.6 million megawatt hours monthly. There is also a modest increase in wind generation, and close to zero changes for all other categories.

Panel B examines natural gas generation more closely. These categories primarily distinguish between whether plants are owned by electric utilities or independent power producers, and whether or not the plants are cogeneration facilities. The two largest categories are "Independent Power Producer Non-Cogen" and "Electric Utility." Both increase substantially in 2012. Generation is essentially flat in all other categories between 2011 and 2012. In some cases (e.g. industrial non-cogen) there are large percentage changes but from a small base level. It is difficult to make definitive statements based on these aggregate data, but this is consistent with plants in these other categories being much less able to respond to market conditions. With industrial, commercial, and cogeneration facilities, electrical output is a joint decision with other processes (e.g. oil extraction or refining, steam production, etc.), which limits the ability of these plants to respond quickly to changes in market conditions.

3.2 Generation Data from CAISO

To complement the EIA data, we next assembled a database using publicly-available records from CAISO. About 90 percent of the electricity used in California is traded through CAISO. All of California's investor-owned utilities and most municipally-owned electric utilities buy power through CAISO. An important exception is the municipally-owned Los Angeles Department of Water and Power (LADWP), which maintains its own electricity generation and also imports power from other states through long-term contracts.

The data from CAISO describe hourly data on electricity generation by broad categories

(thermal, imports, renewables, large hydroelectric, and nuclear). The renewables category is disaggregated into six subcategories (geothermal, biomass, biogas, small hydroelectric, wind, and solar). See CAISO (2013c) for details. Table 1, Panel C describes generation by category in 2011 and 2012. These data corroborate the general pattern observed in the EIA data. From 2011 to 2012, there is a large increase in thermal generation and large decreases in nuclear and hydroelectric generation.

An important advantage of the CAISO data is that they also track imports. Between 2011 and 2012 imports increased from 5.45 to 5.77 million megawatt hours monthly. This is a substantial increase, but offsets less than 1/5th of the shortfall experienced from the SONGS closure, and only about 1/10th of the combined shortfall from SONGS and the decrease in hydroelectric generation. We examine the role of imports in greater depth in Section 5.1, but both the EIA data and CAISO data suggest that California thermal generation played the primary role in making up for the lost generation from SONGS.

3.3 Generation Data from CEMS

We next built a database of hourly emissions, heat input, and electricity generation by generating unit using the EPA's Continuous Emissions Monitoring System (CEMS). The CEMS data contain these hourly data as well as descriptive information for each generating unit, including owner name, operator name, technology, primary and secondary fuel, and vintage. Finally, we match each generating unit to one of the three price locations (South, Central, and North) using the "Control Area Generating Capability List" from CAISO (2013d).

CEMS data have been widely used in economic studies of generator behavior because they provide a high-frequency measure of generation at the generating unit level. See, e.g., Joskow and Kahn (2002); Mansur (2007); Puller (2007); Holland and Mansur (2008); Cullen (2013); Cullen and Mansur (2013); Graff Zivin, Kotchen and Mansur (2014); Novan (Forthcoming). CEMS data are highly accurate because facilities must comply with specific requirements for maintenance, calibration, and certification of monitoring equipment, and because the methodology used for imputing missing data creates an incentive for generating units to keep monitoring equipment online at all times.

During our sample period, 107 plants in California report to CEMS.[8] In 2011, these plants represent 30% of total generation in California and 62% of total natural gas generation. This relatively low fraction of generation covered by CEMS reflects that a large share of California generation comes from nuclear, hydro, and renewables – none of which are in CEMS. In addition, as discussed above, one third of natural-gas fired generation in California is from cogeneration, industrial, and commercial facilities, which are generally not in CEMS. Indeed,

[8] CEMS reporting requirements do not change during our sample period.

generation reported in CEMS in 2011 is 96% of non-cogen natural gas-fired generation by electric utilities and independent power producers reported in the EIA data.

Despite the incomplete coverage, the CEMS data are extremely valuable. They cover the largest thermal plants and the plants that are best able to respond to market changes, in addition to being the only publicly available information on hourly, generating unit-level outcomes. Moreover, by combining the CEMS data with EIA and CAISO data, we are able to get a sense of how much our results might be affected by focusing exclusively on CEMS generating units. Table A2 in the Online Appendix lists the largest plants that do not appear in CEMS. Overall, these plants tend to be quite small, or to be types of facilities (e.g. cogeneration plants, industrial facilities) that are not able to respond quickly to market changes. We empirically examine the responsiveness of these units below.

While CEMS data describe gross generation, for this analysis we would ideally observe net generation. The difference between the two is equal to "in-house load," which is the electricity the plant uses to run, for instance, cooling equipment or environmental controls. As such, net generation is what is sold on the grid. Reliable plant-level or unit-level estimates of the ratio between net and gross generation are not available. In the analyses that follow we use an implied measure of net generation, which we calculate as 95.7% of gross generation. This 4.3-percent difference is the median difference in our sample between net generation from EIA and gross generation from CEMS, after dropping some outliers.[9] Kotchen and Mansur (2014) make a similar comparison using national data, finding a 5-percent mean difference.

3.4 Wholesale Price Data

We also obtained hourly wholesale electricity prices from CAISO. We use prices at three locations: NP15 (Northern California), ZP26 (Central California), and SP26 (Southern California). Figure 1 shows the price difference between Northern and Southern California at 3 p.m. each weekday, a time when transmission constraints are more likely to bind. There is clear evidence of an increase in the post-period price differentials. After the SONGS closure, there are many more days with positive differentials, including a small number of days with differentials that exceed $40 per MWh.

[9]Specifically, we examine generation data for 2005-2011 plants that appear in both CEMS and EIA. We calculate the annual net to gross ratio for each plant, using net generation as reported to EIA and gross generation as reported to CEMS. The median ratio is 0.966, but there are implausible outliers, such that the average is greater than 1. In particular, if some but not all generating units report to CEMS, this ratio can appear larger than 1. Dropping these outliers, the median is 0.957 and the average is 0.926.

4 Empirical Strategy and Generation Regressions

4.1 Creating a Credible Counterfactual

Our objective is to determine which power plants increased generation to make up for the 2,150 megawatts of capacity that became unavailable when SONGS closed in February 2012. Although at first glance this might appear to be a relatively straightforward exercise, simple before-and-after comparisons would not be credible. As we showed earlier, hydroelectric generation was low in 2012. This alone necessitated substantial increases in generation from thermal plants, making it difficult to interpret before-and-after comparisons like our Table 1.

One potential approach for estimating the causal impact of the SONGS closure would have been to use a regression-discontinuity (RD) research design, comparing generation immediately before and after the SONGS closure. This approach has a great deal of intuitive appeal, but is only useful for estimating a very short-run effect, i.e. changes in generation during the days or weeks following the closure. Although this is somewhat interesting, we are much more interested in longer-run changes in generation patterns. In particular, we want to be able to examine June, July and August 2012, when air-conditioning and other factors lead electricity consumption to reach its annual peak. The RD approach is not helpful for examining this peak period because it occurs several months after the closure.

Instead, the approach we adopt in this paper is to construct an econometric model of the relationship between system-wide demand and unit-level generation, and then to use this model to quantify changes in generation post closure. The basic idea is simple. System-wide demand varies substantially hour to hour, as a function of weather and economic activity. Low-cost generating units operate most hours of the year, regardless of system-wide demand, while higher-cost generating units turn on only during relatively high demand hours. The first thing we do is describe this relationship non-parametrically, using a series of regressions.

We estimate these regressions using data from before the closure, when transmission constraints were rarely binding in the California market. These regressions are thus an empirical representation of operating behavior in an unconstrained market, and they primarily reflect differences in marginal cost across generating units. During the post-period, however, we expect transmission constraints and other physical limitations of the grid to change the ordering of generating units. In particular, electricity generated by units in the immediate vicinity of SONGS became more valuable, potentially leading these units to be used even at lower levels of system-wide demand.

As we describe in the introduction, we distinguish between two different effects: (1) the "merit-order" change in generation is when the next generating unit along the marginal cost curve is brought online; and (2) the "out-of-merit" change in generation is when higher cost

generating units that would normally be offline are brought online because of transmission constraints, voltage support, or other considerations. In this section we describe our approach in detail, highlighting the key assumptions required for each stage in the analysis.

An alternative to our ex-post empirical approach would have been to simulate counterfactuals using an engineering model of the electrical grid combined with a structural model of firm optimization. However, our method is better suited to the application we consider for several reasons. First, while Cournot simulations have been used to study two-node transmission problems, the transmission constraints in our application are more complex. In particular, anecdotal evidence suggests that, in addition to congestion across the two main North and South zones, congestion within regions was also important following the SONGS closure. And while engineering models exist that attempt to capture these features (e.g. GE-MAPS), they assume more information than market participants actually have, and they rely on simplifying assumptions that do not reflect changing grid conditions (Barmack et al., 2006). In practice, electric grid system operators use a combination of output from such models and real-time information about system conditions.

Performing counterfactual simulations would also require strong assumptions about generator and system operator behavior. While the objective function for independent power producers is relatively clear, describing behavior by investor-owned utilities is more difficult because they are subject to rate-of-return regulation. System operator behavior is important as well. During this period, CAISO was actively implementing new automated bid mitigation procedures and increasing the use of exceptional dispatches (CAISO 2013b).[10] Modeling these rapidly evolving market practices explicitly poses real challenges and would have required not only imposing these constraints in the model but also making strong assumptions about generators' expectations about these practices.

4.2 Generation Regressions by Category

The core of our econometric model is a system of what we call "generation regressions," which describe non-parametrically the relationship between system-wide demand and generation at individual sources. We estimate these regressions first for broad categories of generation and then later, in Section 4.3, for individual generating units. For the generation regressions by category the estimating equation takes the following form:

$$generation_{it} = \sum_{b} \left(\gamma_{bi} \cdot \ \mathbb{1}\{system\text{-}wide\ demand_t = b\}\right) + \varepsilon_{it}. \tag{1}$$

[10] Bid mitigation is the replacement of submitted bids with default cost-based bids; exceptional dispatch is a manual override of the market optimization algorithm.

The dependent variable is electricity generation for category i in hour t, measured in megawatt hours. We use the categories reported in CAISO data: thermal, large hydro, imports, nuclear, and renewables. In addition, we separate thermal into generation that appears in CEMS and generation that does not, where the latter is calculated as the difference between thermal generation reported by CAISO and thermal generation reported by CEMS.

The only independent variables in the regression are a set of indicator variables corresponding to different levels of total system demand.[11] We divide system-wide demand into bins of equal width, indexed by b. For convenience, we define the bin width as $2{,}150/2 = 1{,}075$ megawatt hours, so that we can assume that system demand increased by two bins following the SONGS closure. We have experimented with alternative bin widths, and the results are similar with both more and fewer bins.

At first glance, this estimating equation would appear to suffer from simultaneity. Keep in mind, however, that electricity demand is both highly inelastic and highly variable across hours. In our sample, peak demand is routinely 150 to 200 percent of off-peak demand, and there is, in addition, enormous seasonal variation in demand driven by lighting and air conditioning. In practice, these exogenous shifts in demand overwhelm cost shocks other supply-shifters in determining equilibrium quantities.

We do not include a constant in the regression, as the indicator variables sum to unity. We could equivalently drop one and interpret the coefficients relative to the excluded bin, but our approach makes it easier to interpret the estimated coefficients. Without including a constant, the coefficients γ_{bi} are equal to the average generation for category i when system demand is at level b. If there were no dynamic dispatch considerations and no plant outages, this coefficient would be equal to zero up until the point when lower-cost generating units had already been turned on to meet demand, and then would be equal to the unit's capacity. Because there are no additional regressors, this is formally equivalent to calculating conditional means for different ranges of system-wide demand.

We estimate equation (1) using hourly data from 2010 through January 31, 2012, the two years leading up to the SONGS closure. We begin the sample on April 20, 2010 because hourly CAISO generation data are not available from before that date. Additionally, we drop a small number of days (fewer than ten) for which data from CAISO are incomplete. Because the coefficients γ_{bi} are allowed to differ by generation category, we estimate six separate regressions, one for each category. Figure 2 plots the estimated coefficients. In all plots, the x-axis is total generation from all sources, divided into bins. The y-axis is average source-specific generation

[11] We have estimated several alternative models that include fixed effects, such as: (i) hour-of-day effects, (ii) month-of-year effects, and (iii) hour-of-day interacted with month-of-year effects. These could control for plant utilization that varies by time of day or by season. Results are very similar across specifications, indicating that these fixed effects add little to our preferred specification with flexible system-wide generation.

in MWh. We plot all six categories using the same scale for the y-axis, so that one can immediately compare both the level and responsiveness of generation.

The CEMS units (Panel A) are very responsive across all quantiles of demand. Large-scale hydro (Panel B) is only somewhat responsive, which is a bit surprising given the potential for using large hydroelectric facilities to follow demand fluctuations.[12] We thought this might be because 2011 had relatively high water supply, so we also examined the generation regression for 2012. Though the overall level of hydro generation is lower in 2012, the slope is about the same. Imports (Panel C) are also somewhat responsive, but only for relatively low demand hours. This pattern is consistent with Bushnell, Mansur and Saravia (2008), who emphasize results from a linear-log specification that implies low import responsiveness during high demand hours. Past the median level of demand, imports are essentially flat. Nuclear (Panel D) and renewables (Panel E) are not responsive, as expected – the nuclear unit (Diablo Canyon) is baseload, and renewable generation is exogenously determined by weather.

It is interesting to compare these results with the aggregate pattern of generation in Table 1. Both show, in some sense, the ability of different generation sources to respond to changes in demand, albeit on very different time scales. The year-to-year comparison suggests that the majority of the response to the SONGS closure came from natural gas generation, and this is consistent with the hour-to-hour responsiveness observed in Panel A. Similarly, most of the other categories showed relatively little increase in 2012, and this accords with the lack of hour-to-hour responsiveness in Panels B–F. Finally, it is important to note that, while hydroelectric resources display some hour-to-hour variation in Figure 2, the year-to-year variation is entirely exogenous – it depends on total precipitation.

4.3 Unit-Level Generation Regressions

The generation regressions by category give a valuable overview, but they provide no detail about which particular plants tend to be the most responsive to system-wide demand, nor about the geographic location of production. Therefore, we next estimate generation regressions for each unit that appears in the CEMS data. The estimating equation for these regressions is very similar to equation (1) except the unit of observation is now the individual generating unit j,

$$generation_{jt} = \sum_b \left(\alpha_{bj} \cdot \ \mathbb{1}\{net\ system\text{-}wide\ demand_t = b\}\right) + e_{jt}. \tag{2}$$

The right-hand side bins are now defined over total generation by all California CEMS units. This is the *net* or *residual* demand, after generation from renewables, imports, and non-CEMS

[12] However, hydro operators are subject to minimum and maximum flow constraints.

units has been subtracted from the total system demand. We use this rather than total system demand because we want to identify the ordering within the category of natural gas units.

We estimate these unit-level generation regressions using two separate samples corresponding to before and after the SONGS closure. Observing plant behavior before the closure allows us to construct a counterfactual for what would have occurred if SONGS had not closed. As we describe in the next section, the behavior of the natural gas units before the closure (the "pre-period") can then be compared to the behavior after the closure (the "post-period"). Returning to equation (2), note that we use net demand because we want to attribute changes from the pre-period to the post-period only to the SONGS outage, and the residual demand will not be confounded by concurrent changes to renewables, hydro, or demand. We elaborate on this below.

For the pre-period, we again use data from April 20, 2010 to January 31, 2012, the year and a half leading up to the SONGS closure. We drop four generating units which are owned by the Los Angeles Department of Water and Power (LADWP). As described earlier, LADWP maintains its own electricity generation and also imports power from other states through long-term contracts, and it is not part of the CAISO market. Finally, for the main analysis we exclude generating units that enter or exit during our sample period, focusing only on continuously-operating generating units plus Huntington Beach units 3 and 4 (which operated through most of our sample period, but were converted to synchronous condensers in 2013). We explore entry and exit further in the Online Appendix, arguing that excluding the units that enter or exit during our sample period is unlikely to bias our results.

Sample graphs of the coefficients from these pre-period unit-level regressions are shown in Figure 3. We show twelve units: the four largest units for each of three technologies. As can be seen in Panel A, the combined cycle plants tend to turn on, and even reach capacity, at fairly low levels of system demand. These units are generally new, large, and efficient. The combustion turbines in Panel B are turned on at higher levels of demand and have much smaller capacity. Finally, the boilers (Panel C), which are generally large and old, are turned on only at high levels of system demand.

For the post-period, we use data from February 1, 2012 through January 31, 2013. These are the first twelve months after the SONGS closure. While it would be interesting to examine longer-run changes in the market, this gets difficult because the market is changing over time, both endogenously as costly transmission investments are made in response to the SONGS closure, and exogenously as, for example, new generation sources come online.[13]

[13]In the Online Appendix, we include results estimated with a post-period which goes through June 30, 2013, and the main results are similar but somewhat attenuated. This is exactly what you would expect as investments in new transmission capacity begin to relieve the constraint.

4.4 Merit-Order and Out-of-Merit Effects

We thus have a set of coefficients α for each of 21 bins at 184 generating units in 2 time periods, for a total of over 7,000 coefficients. We summarize these estimates as follows. We define the "merit-order" change in generation at a given unit caused by the SONGS closure as: maintaining the ordering of units along the marginal cost curve, while requiring an additional 2,150 megawatt hours of generation to fill the SONGS gap. Recalling that width of each bin is equal to 1,075 megawatt hours, the merit-order change (induced by the SONGS closure) across all bins b and all generating units j in a geographic region (J_{North} or J_{South}) is:

$$\sum_{b>2}\sum_{j\in J}\left(\alpha_{bj}^{pre}-\alpha_{b-2,j}^{pre}\right)\cdot\theta_b^{post} \tag{3}$$

where θ_b^{post} is the fraction of hours that system-wide demand was in bin b during the post-period.[14] The "out-of-merit" effect is the change in generation from the pre-period to the post-period, conditional on a given level of system demand:

$$\sum_{b}\sum_{j\in J}\left(\alpha_{bj}^{post}-\alpha_{bj}^{pre}\right)\cdot\theta_b^{post}. \tag{4}$$

Out-of-merit effects can be positive or negative, reflecting whether units are operating more or less than would be predicted from pre-period behavior. We argue in the analysis that follows that these differences between the pre- and post-periods are attributable to transmission congestion and other physical limitations of the grid arising from the SONGS closure. This is a strong assumption and, as with any before-and-after comparison, it is important to think carefully about potential confounding factors.

To examine broad patterns of transmission congestion, we begin by presenting results in which we estimate equation (2) at the regional, rather than generating unit level. This is numerically equivalent to summing across unit-level results, since in the tables which follow we are reporting the linear sum of coefficients across units within a region. In section 6, we analyze plant-level results. When estimating the standard errors, we cluster by sample month to allow for arbitary spatial correlation and serial correlation within sample month. To examine whether this approach sufficiently accounts for serial correlation, we regressed the residuals on their lags. Beyond fifteen days, the estimated coefficients are close to zero and not statistically significant.

Additionally, we evaluate the merit-order and out-of-merit changes for subsets of hours

[14] Note that this cannot be calculated for levels of thermal generation without a pre-period counterfactual, i.e. $b = 1$ and $b = 2$. In our sample, these levels of thermal generation do not appear in the post period, so in practice this is not an issue.

when transmission constraints are most likely to bind. These calculations are exactly the same as equations 3 and 4 except we use observations from only a subset of post-closure hours. We consider two such subsets, each totaling approximately 5% of hours. First, we define weekday summer afternoons as 2 p.m. to 5 p.m. in months June through September. Second, we define high demand hours when total CEMS generation was in the 13th quantile (greater than 13,837 MWh); this leaves approximately the same number of observations as in the weekday summer afternoon results. We verify that both definitions are highly correlated with congestion as defined by the price differential between North and South. They are also correlated with one another, with a simple correlation of 0.30.

The primary assumption for these calculations is that the *ordering* of units along the marginal cost curve in 2012 would have been the same as in 2010 and 2011, had SONGS not closed. There are many reasons to think this is a reasonable assumption. These are all natural gas plants, so there is no inter-fuel substitution, and the ordering among plants is essentially a monotonic ordering by heat rate. Moreover, while there were large changes in hydroelectric and renewables generation in 2012, these changes would not have affected the ordering of the natural gas units. In the Online Appendix, we explore these and several additional potential confounding factors in depth. Our approach is not a panacea. As with any before-and-after comparison, we cannot rule out the possibility that our estimates are affected by other factors that are changing in the market at the same time. We conclude, however, in examining each potential confounding factor carefully, that any bias is likely to be small in magnitude. Moreover, it is hard to envision any alternative explanation for the particular pattern of regional and temporal out-of-order effects that we observe.

5 Regional Impacts

5.1 Impact on Generation

Table 2 describes the effect of the SONGS closure on the geographic pattern of generation in California. The reported estimates are average hourly changes in MWh. Panel A reports effects for all hours during the twelve months following the closure. The merit-order change in generation is similar in the North and the South, with both regions increasing generation by about 900 MWh per month. The Central California column represents many fewer plants, and accordingly a smaller merit-order change (300 MWh). By design, the total merit-order effect is approximately equal to 2,150 MWh, the lost generation from SONGS. This geographic pattern reflects where in the state thermal resources are located. Without any transmission constraints, our estimates imply that about 40% of the lost output from SONGS would have been produced by plants located in Southern California.

The out-of-merit estimates show the displacement of generation from Northern generating units to Southern units. Relative to what we would have expected in a world without transmission constraints, the Southern units increased generation by 150 MWh, while the Northern units decreased by 140 MWh. To put this in perspective, the average plant-level capacity is around 380 MW in the South and around 270 MW in the North, so these effects are approximately half the size of a typical plant.

The results are starker when the sample is limited to the hours in which transmission constraints are most likely to bind. On weekday summer afternoons (Panel B), the out-of-merit effect almost doubles, to a 237 MWh increase in the South and 260 MWh decrease in the North. In the 5% of hours with the highest level of system demand (Panel C), the out-of-merit effect is an increase in the South of 431 MWh, and a decrease in the North of 381 MWh. Thus, the estimates indicate that as much as 75% of the lost generation from SONGS was met by plants in Southern California. To get a sense of the magnitude, the out-of-merit effect is comparable to an increase in capacity factor of three percentage points in the South and a decrease of three percentage points in the North.

These results implicitly assume that the entire displaced SONGS generation (2,150 MWh) was met by in-state CEMS units. This is a reasonable approximation given the lack of responsiveness in all other categories of generation observed in Figure 2. The one potential exception is imports, which are responsive over some ranges of demand. To account for this, we calculated the merit-order impact on imports of a shock to total demand equal to 2,150 MWh, using the generation regression for imports. This exercise implies that around 25% of the lost generation from SONGS would have been replaced by imports. One could imagine adjusting the merit-order estimates in Panel A of Table 2 accordingly. For weekday summer afternoons and high demand hours, however, we find a very small response in imports, consistent with the visual evidence in Figure 2. On weekday summer afternoons, only 4 percent of the lost generation would have made up by imports, and in high demand hours it would have been less than 1 percent. While the merit-order effects depend on how responsive imports are, the out-of-merit effects do not, as imports did not change transmission constraints. Further details, discussion, and figures plotting post-period generation regressions by category are presented in the Online Appendix.

The table also reports standard errors. The merit-order changes are estimated with a high degree of statistical precision and all nine estimates are strongly statistically significant. The estimated out-of-merit changes are less precise, reflecting that whereas the merit-order changes are estimated using the pre-period only, the out-of-merit effects reflect differences in estimated coefficients between the pre-period and the post-period. In the Online Appendix, we report results from a series of placebo tests, which show that it would have been unusual to

observe this magnitude and pattern of out-of-merit effects due to chance alone. In particular, we repeat the analysis six times using the exact same specification, but with different years. In the first placebo test, for example, we estimate the model as if SONGS had closed in January 2007 rather than January 2012. Overall, the estimated out-of-merit effects in these other years do not follow the pattern observed in 2012. Some of the estimates are similar in size to our main results. However, when one looks closely at non-zero out-of-merit effects in other years, they tend to be driven by long outages. To demonstrate this, we show several diagnostics on the unit-level out-of-merit effects. In the years with the largest out-of-merit placebo effects, the standard deviation, skewness, and kurtosis are all larger (in absolute terms) than in 2012, indicating large year-to-year changes in generation at a few individual plants rather than correlated changes in generation across many plants.

5.2 Impact on Costs

We next quantify the change in the total cost of production associated with these generation impacts. To do so, we must first calculate the marginal cost for each generating unit. As is common in the literature, we calculate marginal cost using information on heat rates, fuel prices, and variable operations and maintenance costs (VOM): $MC_j = heat\ rate_j \cdot fuel\ price_j + VOM_j$. For the unit-level heat rate, we divide the total heat input over our time frame (in MMBtus) by the total net generation (in MWhs). This abstracts from ramping rates, as is common in the literature. We obtain daily natural gas prices from Platts Gas Daily and calculate the average post-period price. We focus, in particular, on the PG&E City Gate price for the North, and the SCG City Gate price for the South. For VOM, we assume \$3.02 per MWh for combined cycle plants and \$4.17 per MWh for all other plants (in 2009\$), following CEC (2010). The resulting marginal cost estimates range from \$24 per MWh for generating units with favorable heat rates to \$81 per MWh for units with high heat rates.

In Figure 4, we plot the marginal cost curve for electricity in California. We use our estimates of marginal cost for all thermal units. For the capacity of these units, we use the maximum observed hourly generation in our sample. For hydroelectric, renewables, and nuclear, we proxy for capacity using the average hourly generation in the post-period (February 2012 through January 2013), from CAISO. While these types of generation have higher rated capacities, the average generation in the post-period is more relevant given constraints set by weather conditions. We assume zero marginal cost for hydro and renewables production. For the marginal cost of nuclear units, we use a nuclear fuel cost estimate of \$7.08 per MWh (in 2012\$) from Table 8.4 of the EIA's *Electric Power Annual* (EIA 2012), plus a nuclear VOM

estimate for California of \$5.27 per MWh (in 2009\$) from CEC (2010).[15]

We overlay on the marginal cost curve a histogram of total hourly generation in the post-period. In most hours, the marginal generating unit is a combined cycle natural gas unit, with marginal cost (given the average post-period natural gas price) of around \$27 per MWh. In high demand hours, however, the marginal unit is typically either a combustion turbine or a boiler (again, fueled by natural gas), with marginal cost around \$ 40 per MWh.

To quantify the cost impact of the SONGS closure we run regressions similar to the unit-level generation regressions, except the dependent variable is now the cost of generation rather than the quantity:

$$(MC_j \cdot generation_{jt}) = \sum_b (\delta_{bj} \cdot \ \mathbb{1}\{net\ system\text{-}wide\ demand_t = b\}) + \mu_{jt}. \tag{5}$$

The advantage of using this regression is that we can again decompose the total change in cost into merit-order and out-of-merit changes. Results are given in Table 3. Taking a weighted average across all hours, the merit-order increase in total cost of thermal generation was \$29,000 in the South, \$8,000 in the Central region, and \$27,000 in the North – totalling \$63,000 statewide each hour. The average cost implied is approximately \$29 per MWh.

It is worth noting that this estimate of \$63,000 assumes that none of the lost generation from SONGS was replaced by imports. As described above, imports made up approximately 25 percent of the lost generation on average, across all hours. Given that the California marginal cost curve is quite elastic in most hours, the marginal cost of out-of-state generation necessarily must have been close to the marginal cost of the in-state generation. As such, we expect our estimate of \$63,000 to be close to the true merit-order change in total cost.

The out-of-merit changes are also significant. While total cost increased by \$7,100 in the South and \$500 in the Central region, it decreased by \$3,000 at Northern generating units because of the decrease in quantity. System-wide, this implies an increase of \$4,500 each hour coming from the out-of-merit changes in generation. While lower-cost units were available in the North, they could not be used because of the transmission constraints and other physical limitations of the grid. This out-of-merit effect reflects not only North-South transmission constraints, but also *local* transmission constraints in and around San Diego and Los Angeles, as well as other physical limitations of the grid. As we discuss briefly later in the paper, part of the challenge with SONGS closing was that there was now very little generation in northern San Diego county that could be used to boost the voltage of electricity transmitted from far away. Maintaining some "reactive" power locally was another reason why units would have

[15] Biomass/biogas are not shown, as marginal cost numbers are not available. This marginal cost of biomass generation is likely in the range of the combined cycle units with an average production over this period of around 500 MWh.

been operated out-of-merit.

Thus the total cost increase at thermal power plants statewide, including both merit-order and out-of-merit effects, is almost $68,000 per hour. This amounts to a 13 percent increase in total in-state generation costs.[16] As another point of comparison, the average post-period price in the California wholesale electricity market (quantity-weighted) was $32 per MWh. Multiplying this by total quantity (i.e. 2,150 MWh) gives $68,000 per hour. The two measures are quite close together because the supply curve is fairly elastic in most hours throughout the year. Thus the cost of the marginal generating unit is not very different from the cost of inframarginal units. Using our estimate of the marginal cost of California nuclear plants (described above) of $12.8 per MWh implies that the marginal cost of generation at SONGS would have been around $28,000 each hour. This difference in costs implies that the SONGS closure increased the cost of generation by $350 million in the first twelve months. Of this, the out-of-merit portion is $4,500 per hour, implying a total of $40 million in the first twelve months following the closure. Table 4 summarizes these total impacts.[17]

Panels B and C of Table 3 report estimates of the cost changes for weekday summer afternoons and high demand hours, when transmission constraints are more likely to bind. The merit-order effects are larger than in Panel A, because the marginal generating units at these hours are higher up on the marginal cost curve. The change is particularly high in the South, where the generation impacts were larger. The out-of-merit changes in total cost are also higher than in Panel A, reflecting a combination of larger out-of-merit changes in generation and higher marginal costs. The system-wide total change in thermal costs is approximately $78,000 per hour on weekday summer afternoons, and around $84,000 per hour in high demand hours. As we describe above, imports did not substantially increase in the weekday summer afternoon and high demand hours, so we expect these estimates to be close to the true total change in cost. For comparison, the average weekday summer afternoon wholesale price (quantity-weighted) was $49 per MWh. Multiplying this by SONGS capacity gives $106,000 per hour. The same calculation for high demand hours (Panel C) also gives $106,000 per hour. These measures are considerably higher than our estimate because supply is relatively inelastic during these hours; the marginal generating unit has a much higher cost than the inframarginal units.

[16] To calculate this, we assume that the average hourly cost for residual thermal generation (i.e., not observed in the CEMS data) is equal to the average cost we observe in our sample.

[17] These numbers reflect our assumptions regarding VOM costs. We are assuming that VOM at SONGS is substantially higher than VOM at the natural gas plants that came online when SONGS closed. If we were to assume equal VOM, the total cost of replacing the lost generation from SONGS would rise by about $40 million.

5.3 Impacts on Emissions

In addition to the private cost of generation we calculate above, we quantify the impact of the generation changes on carbon dioxide emissions. Using the CEMS data, we calculate unit-specific carbon emissions rates. We then use the same type of regression as we used for the generation and cost changes, but now with carbon dioxide emissions, in metric tons, as the dependent variable:

$$(carbon\_rate_j \cdot generation_{jt}) = \sum_b (\lambda_{bj} \cdot \ \mathbb{1}\{net\ system\text{-}wide\ demand_t = b\}) + \nu_{jt}. \qquad (6)$$

While California power plants are currently covered by a carbon cap and trade program, they were not yet covered in 2012. As a result, any increase in carbon dioxide emissions caused by the SONGS closure would not have been offset. We estimate an increase of 1,030 tons per hour.[18] For comparison, the average hourly total emissions at CEMS plants was around 3,800 tons in 2010 and 3,100 tons in 2011. The central value of the social cost of carbon used by the federal government for regulatory impact analysis is 32 $/ton (in 2007$) (IWG 2013). For this cost of carbon, our estimates imply a social cost of the additional emissions of almost $320 million, in 2013 dollars. These carbon calculations, as with the cost calculations, assume that the none of the lost generation from SONGS was replaced by imports. If the emissions rates of marginal out-of-state generators are comparable to the emissions rates of the CEMS plants we observe, then our carbon calculations will still be correct. If, however, there are *marginal* generators out-of-state that are fueled by coal, then our carbon estimates will be a lower bound.

We also examine the impact on sulfur dioxide and nitrogen oxides emissions. Our estimates imply that the SONGS closure increased emissions of both pollutants. However, natural gas plants emit small enough amounts of these criteria pollutants that the implied economic cost of the change in emissions is small compared to the carbon dioxide impacts. See Muller and Mendelsohn (2012) for recent estimates of marginal damages. Moreover, a portion of NOx emissions are capped in the RECLAIM market around the Los Angeles area, so some of these increases may have been offset by other sectors.

[18] We do not report the geographic breakdown nor the difference in high demand hours, although they match what one would expect given the generation changes in Table 2. Since carbon dioxide is a long-lived, global pollutant, these breakdowns are not relevant.

6 Plant-Level Impacts

Our empirical approach generates estimates of merit-order and out-of-merit effects not only at a regional level, but also for individual plants. Averaging across all hours, the five largest merit-order increases in generation were all at large combined-cycle plants with low marginal cost. As Figure 4 shows, in most hours the equilibrium is at a fairly elastic portion of the supply curve, with costs around $27 per MWh. The largest positive out-of-merit increases tend to be in the South and the largest decreases in the North, as expected. Full results are provided in the Online Appendix.

The differences between the South and North are starker during hours when transmission constraints were most likely to bind. Not surprisingly, the merit-order increases are largest at plants with much higher marginal cost: around $40 per MWh. The largest out-of-merit increases are exclusively at Southern plants. Also, as expected, several of the largest out-of-merit decreases are at plants in the North. There are two important exceptions, however. The two largest out-of-merit decreases in high demand hours were at plants in the South: Alamitos and Redondo, both owned by AES. These two large plants were on the margin in high demand hours: they appear in Panel A as plants with large merit-order changes. Moreover, given their location in the South, they would have been expected to have out-of-merit *increases*.

To illustrate the anomaly these plants represent, we show in Figure 5 estimated out-of-merit effects by plant for high demand hours, separated by region. The AES plants are shown with black lines, while all other plants are shown with orange lines. While the other Southern California plants generally exhibit positive out-of-merit effects, the estimated out-of-merit effects for two of the three AES plants are clearly large and negative.

We view the AES out-of-merit decreases as consistent with the exercise of market power. As it turns out, the AES plants were operated through a tolling agreement with JP Morgan Ventures Energy Corporation, a subsidiary of JPMorgan Chase. At the request of the California and Midcontinent System Operators (CAISO and MISO), the Federal Energy Regulatory Commission has alleged market manipulation by JP Morgan at these and other plants.[19] FERC, CAISO, and MISO asserted that JP Morgan engaged in twelve different manipulative bidding strategies between September 2010 and November 2012 in both the California and Midcontinent markets. Some of the strategies, particularly in 2011, were designed to lead the independent system operator to schedule the generating units even when it was uneconomical to do so, then to pay prices above the wholesale price through so-called make-whole payments.

[19] To understand FERC's charges against JP Morgan it is helpful to have a bit of broader legal context. Regulatory oversight of electricity is different than for many goods, in that it is illegal to exercise unilateral market power. FERC is charged with a statutory mandate dating back to 1935 which requires wholesale electricity prices to be "just and reasonable," allowing for the recovery of production costs and a "fair" rate of return. See Wolak (2005) for additional discussion.

Other strategies, particularly in 2012, involved submitting extremely high bids but relying on the ISO's dynamic scheduling constraints to lead the bids to be accepted. For details on the individual strategies, see FERC (2013). In 2013, JP Morgan agreed to pay a civil penalty of $285 million and to disgorge $125 million in alleged unjust profits.

Given the level of market power exercised during the California electricity crisis (Borenstein, Bushnell and Wolak, 2002), it may be a bit surprising that we do not see evidence of widespread market manipulation. However, CAISO was actively engaging in mitigation of local market power over this time period (CAISO 2013b). In principle, this could have had two effects: directly mitigating any attempts to exercise market power, and also discouraging firms from even attempting.

It would be interesting to use our results to calculate the profit earned by AES by their alleged behavior, potentially then comparing this number to the settlement with FERC. Several things prevent us from being able to do that. First, since FERC alleged market manipulation in both the pre- and post-periods, we do not know whether the out-of-merit decreases at Alamitos and Redondo are a result of unusually high generation in 2011 or withholding in 2012. Second, the settlement with JP Morgan is still relatively recent, so it is hard to compare behavior before and after the settlement. As more data become available from post-settlement, it might be possible to do more analysis. Finally, much of the manipulation alleged by FERC was aimed at earning revenues through exceptional dispatch and other out-of-market operations, and we do not observe these payments.

We do, however, re-examine our main results in light of the FERC investigation. In the Online Appendix we again present estimates of the regional impact (as in Table 2), but this time separating three plants owned by AES from the other Southern plants. The out-of-merit increases in the Southern units are even larger than in Table 2, once the plants with alleged market manipulation are separated out. We believe this validates our overall approach in two important ways. First, it shows that our out-of-merit estimates do indeed show the effects of the transmission constraints between the Northern and Southern markets. Second, it suggests that our out-of-merit estimates can serve as a valuable diagnostic tool, pointing to generating units where one might suspect non-competitive behavior.

7 Discussion

In Section 7.1 we compare our estimates of the value of transmission with available estimates in the literature for the cost of relieving transmission congestion. Then in Section 7.2 we step back and think more broadly about Southern California Edison's decision to close SONGS.

7.1 Benefits vs. Costs

Of the estimated $350 million in increased annual generation costs, we attribute $40 million to transmission constraints and other physical limitations of the grid. This reflects Southern plants operating too much, Northern plants operating too little, and intra-regional misallocation of generation across units. When the decision was made to close SONGS, it still had ten years left on its current operating license with the NRC.[20] Over this ten-year horizon with a 6.6% discount rate (EIA 2013a), the annual cost of $40 million implies a present discounted value of $300 million.

It is interesting to compare this $300 million, which reflects the potential benefit from additional transmission capacity, with cost estimates. There are several ways these transmission constraints could be relaxed. One approach would be to build an additional high-voltage (500-kV) transmission line along the existing 'Path 15' corridor, an 84-mile path connecting Northern and Southern California. The advantage of increasing capacity of existing transmission lines is that it avoids much of the siting challenges inherent in opening new corridors. A similar project in Path 15 was completed in 2004 and cost almost $370 million.[21]

Another alternative would have been to add new generation capacity in Southern California. Construction costs for a conventional combined-cycle natural gas plant in California are about $1100 per kilowatt (EIA 2013c), so to build a plant that could replace the entire 2,150 MWs from SONGS would cost about $2.4 billion. This is considerably larger than the implied cost of the transmission constraints, but, of course, a new plant would both relax the transmission constraints and generate electricity.

There may also be lower-cost alternatives available. Part of the challenge with the SONGS closure was voltage regulation. Electricity gradually drops in voltage when it is transmitted long distances, so some local generation is necessary to complement electricity produced far away. Much of the attention since the SONGS closure has been on adding local generation, and in particular, on adding generation that provides "reactive" power that maintains voltage, making it possible to bring in more power produced far away. For example, in 2013 two generators at Huntington Beach Plant were converted to synchronous condensers to provide local voltage support. According to CAISO (2013a) this project cost $15 million, making it relatively inexpensive compared to capacity and generation additions.

Thus overall it appears there are some infrastructure investments that would pass a cost-benefit test. Expanding 'Path 15' appears to just barely pass a cost-benefit test, but local

[20] Reactor number two was licensed through February 2022, and reactor number three was licensed through November 2022. See Appendix A of NRC (2012).

[21] See the Western Area Power Administration's 2004 "Path 15 Upgrade Project" Fact Sheet at http://www.wapa.gov/sn/ops/transmission/path15/factSheet.pdf. We multiplied the construction cost by 1.20 to reflect year 2013 dollars.

voltage support investments like the Huntington Beach Project are inexpensive enough to pass a cost-benefit test even if they only partially relieve the constraints. CAISO seems to agree with this assessment and since 2013 has been taking steps to expand local transmission capacity in and around San Diego County (CAISO 2013e; CAISO 2014).

7.2 The Decision to Close SONGS

More broadly, an appealing feature of our analysis is that it provides some of the information necessary to step back and evaluate whether it was socially efficient to retire SONGS. This depends on the value of the electricity that SONGS would have generated during the ten years left on its license, the fixed costs of repairing the plant and keeping it open, and all relevant externalities.

We find that the SONGS closure increased generation costs by $350 million during the first twelve months, after accounting for avoided generation costs at SONGS. In addition, we find that closing SONGS caused carbon dioxide emissions to increase by an amount worth almost $320 million. Thus, the economic cost of closing SONGS was about $670 million in the first twelve months.

These costs must be compared with the benefits of closing the plant. Although the marginal cost of nuclear generation is low, its annual operations and maintenance costs are substantial, about $340 million per year.[22] In addition, there are important external costs associated with operating a nuclear power plant. Some were concerned, for example, that SONGS' troubles signaled increased risk of a major accident. Quantifying these risks is very difficult, but even a tiny probability of a catastrophic nuclear accident could outweigh the benefits of keeping the plant open.

Another important practical complication is that it was not clear when the plant would have been able to reopen. When Southern California Edison made the decision to permanently retire the plant, they were waiting to hear from the Nuclear Regulatory Commission whether they would ever be allowed to restart SONGS. The NRC had already warned SCE that it might be a year or more before a final decision would be made, implying real uncertainty about timing and about the cost of any required repairs. Given this uncertainty, Southern California Edison's decision appears to pass a private cost-benefit test.

It is also worth noting that the costs of closing the plant would have been much higher if natural gas prices had not fallen so much in recent years. At the level of natural gas prices seen in 2007, for instance, the increase in generation costs from the closure of SONGS would have

[22] The Cost of Generation Model from CEC (2010) reports an annual fixed O&M cost for California nuclear plants of 147.7 $/kW-yr, in 2010 dollars. We multiplied this by SONGS' capacity of 2,150 MW and we translated into current dollars. This number closely matches regulatory documents, in which SCE had forecast fixed O&M costs of $346 million per year prior to the closure (CPUC 2012).

been two or three times larger. This is in line with the observation made by some industry analysts that the shale gas boom has severely worsened the economics of existing nuclear plants. Historically nuclear plants earned substantial operating profits (Davis and Wolfram, 2012), but more recently these profits have been eroded by falling wholesale electricity prices (EIA 2014). Along a similar vein, the convexity of the supply curve implies that costs could have been much higher had the system been further stressed by an extended period of hotter-than-average weather or an outage at another major power plant.

8 Conclusion

Our paper uses evidence from the SONGS closure to quantify the value of electricity transmission in California. We find that the SONGS closure increased the private cost of electricity generation in California by about $350 million during the first twelve months. Of this, $40 million reflects transmission constraints and other physical limitations of the grid that necessitated that a high fraction of lost generation be met by plants located in the Southern part of the state. These constraints also increased the scope for market power, and we find evidence consistent with one company acting non-competitively.

We also find that the closure had a large environmental impact. Because virtually all of the lost production from SONGS was replaced by natural gas generation, the closure increased carbon dioxide emissions by 9 million metric tons during the first twelve months. At $35 per ton, the economic cost of these emissions is almost $320 million. A large fraction of the world's nuclear plants are beginning to reach retirement age, and it is important to take these external costs into account as decisions are made about whether or not to extend the operating lives of these plants.

In addition, the analysis corroborates long-held views about the importance of transmission constraints in electricity markets (Bushnell, 1999; Borenstein, Bushnell and Stoft, 2000; Joskow and Tirole, 2000) and contributes to a growing broader literature on the economic impacts of infrastructure investments (Jensen, 2007; Banerjee, Duflo and Qian, 2012; Borenstein and Kellogg, 2014; Donaldson, Forthcoming). Infrastructure facilitates trade and reduces price dispersion, but it also affects market structure, and this is true not only for electricity but also for a broad range of tradable goods (Ryan, 2013).

Our results also illustrate the challenges of designing deregulated electricity markets. Wolak (2014) argues that while competition may improve efficiency relative to regulated monopoly, it also introduces cost in the form of greater complexity and need for monitoring. Transmission constraints add an additional layer to this complexity, by implicitly shrinking the size of the market. Constraints increase the scope for non-competitive behavior, but only

for certain plants during certain high-demand periods. Understanding and mitigating market power in these contexts is difficult and requires an unusually sophisticated regulator.

Despite these challenges, the experience in California in 2012 also provides some cause for optimism. An enormous generating facility closed suddenly and unexpectedly during a year with low hydroelectric generation, yet there was essentially no disruption in supply and wholesale prices remained steady. In part, these 'steady' prices were only an illusion, driven by a lucky coincidence in the form of decreased natural gas prices. However the experience also points to a more mature, more flexible market that, although imperfect, provides many of the right incentives for generation and investment.

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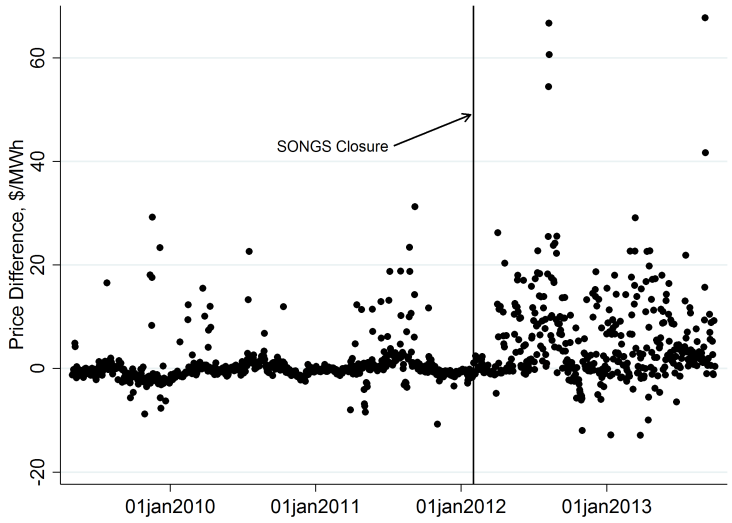
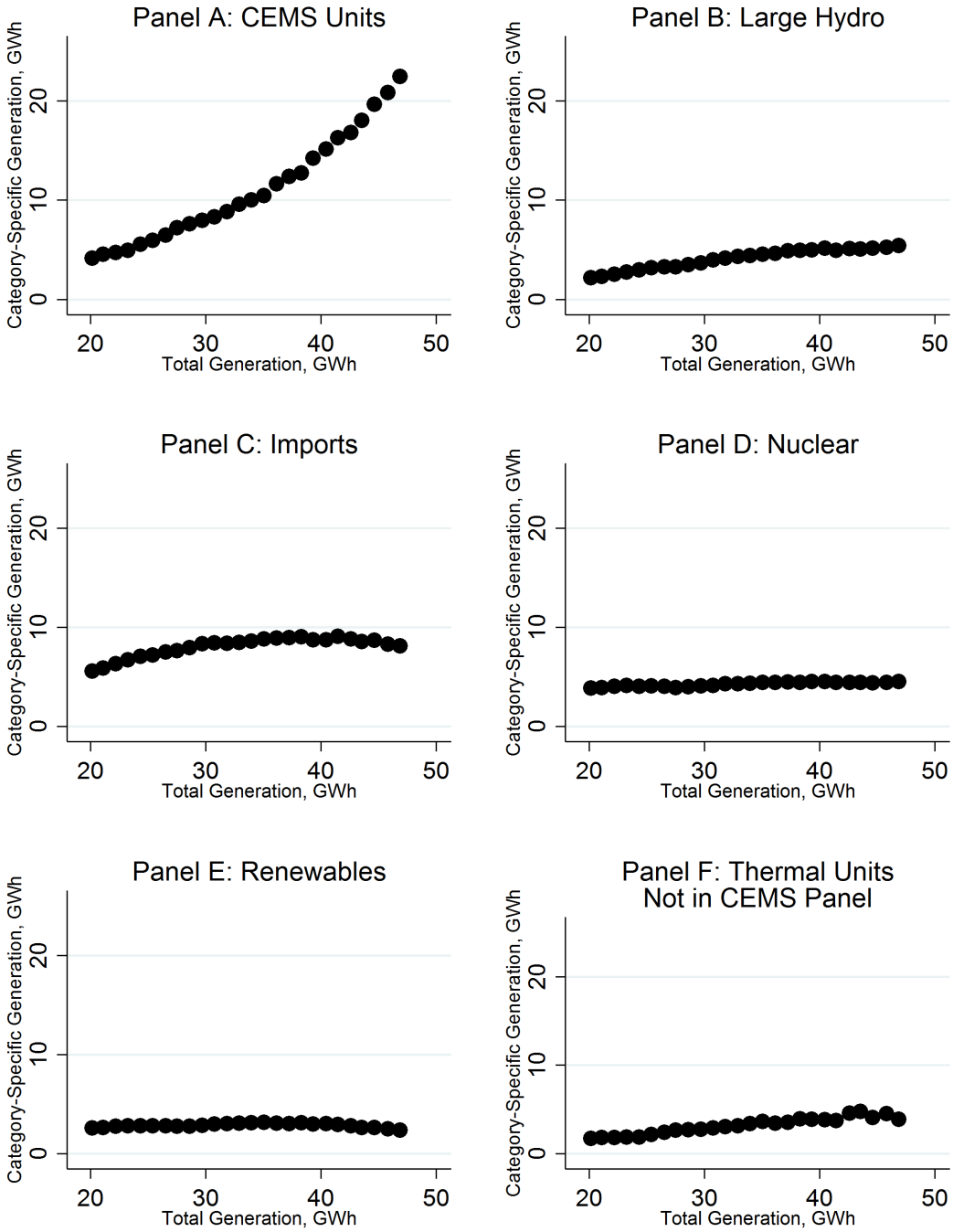
Figure 1: Price Differential, South versus North



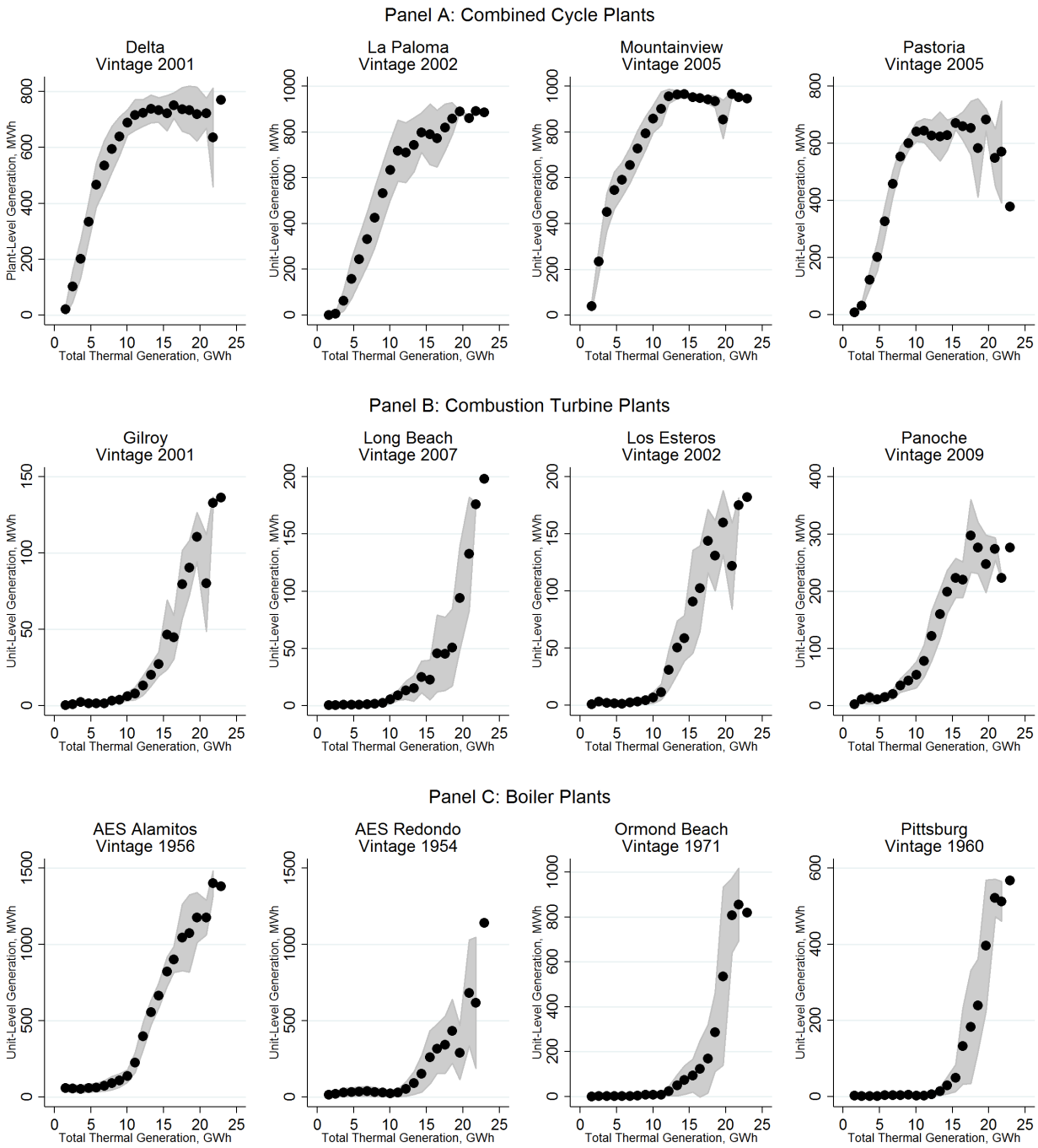
Note: This figure plots daily wholesale electricity price differentials at 3 pm between May 2009 and September 2013. Weekends are excluded. For each day, we calculate the price difference between Southern and Northern California. The vertical line indicates January 31, 2012, the day the second SONGS unit was shut down.

Figure 2: Generation Regressions by Category



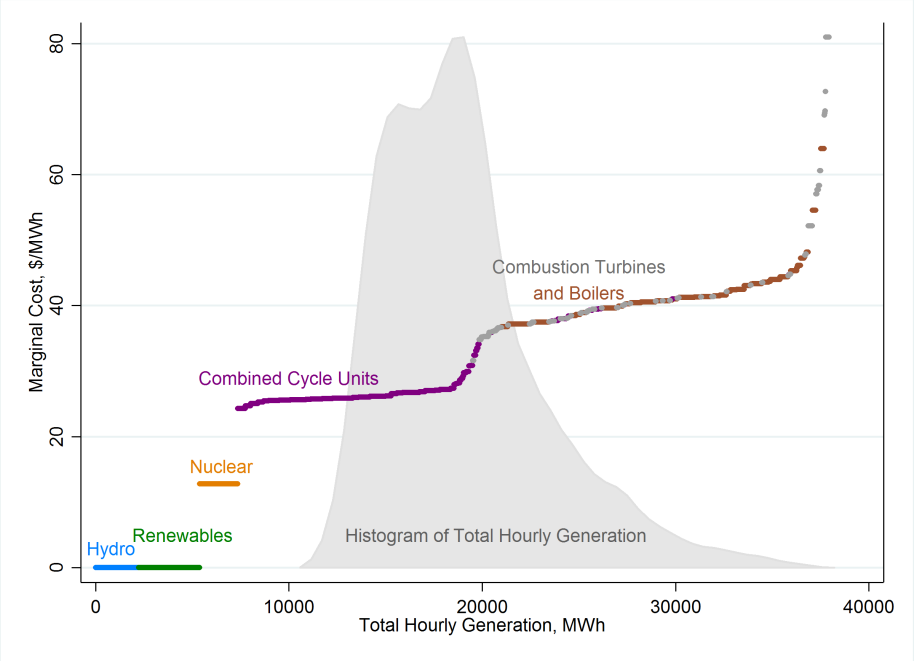
Note: These figures plot the coefficients from six separate regressions. As described in detail in the text, these regressions are estimated using hourly data from April 20, 2010 until January 31, 2012. The x-axis is total generation from all sources, including imports, and the y-axis is average generation, in MWh, for that category of generation. For the non-CEMS thermal units in Panel F, we have subtracted total CEMS generation in our balanced panel from total thermal generation as reported by CAISO. The 95% confidence intervals are not shown, because they are extremely narrow for all six panels.

Figure 3: Generation Regressions by Individual Plant



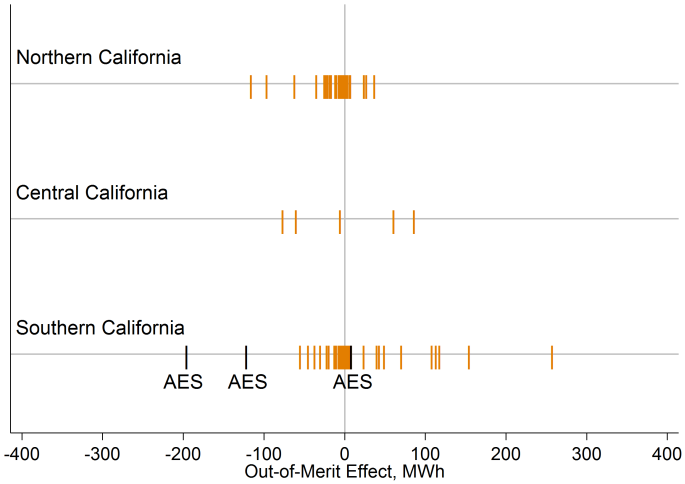
Note: These figures plot the coefficients from 12 separate plant-level generation regressions, for the four largest plants within three technology types as indicated in the panel headings. As described in detail in the text, these regressions are estimated using hourly data from April 20, 2010 until January 31, 2012. The x-axis is total generation from all plants in the CEMS panel and the y-axis is average generation, in MWh, for that individual plant. The grey areas show 95% confidence intervals, where standard errors are clustered by sample month.

Figure 4: The Marginal Cost of Electricity in California, 2012



Note: This figure was constructed by the authors using their measures of marginal cost and capacity for electricity generating resources in the state of California in 2012. Imports are not included. For details, see the text.

Figure 5: Plant-Level Out-of-Merit Changes in High Demand Hours



Note: This figure plots plant-level hourly average out-of-merit changes by region. High demand hours are defined as hours when total CEMS generation was in the 13th quantile (13,837 MWh) or greater. Estimates for AES-owned plants are indicated with black lines, while all other estimates are orange. Details on the calculations are given in the text.

Table 1: California Electricity Generation, 2011-2012

	Average Monthly Generation, Million MWh 2011	Average Monthly Generation, Million MWh 2012	Change
Panel A: By Generation Category, EIA Data			
Natural Gas	7.41	9.97	2.56
Wind	0.65	0.81	0.17
Solar (PV and Thermal)	0.07	0.12	0.04
Other Renewables	0.50	0.53	0.02
Geothermal	1.05	1.04	0.00
Coal	0.17	0.11	-0.05
Other Fossil Fuels	0.29	0.22	-0.08
Hydroelectric	3.54	2.28	-1.25
Nuclear	3.06	1.54	-1.51
Panel B: By Type of Natural Gas Plant, EIA Data			
Independent Power Producer Non-Cogen	2.63	4.48	1.85
Electric Utility	2.24	2.98	0.73
Industrial Non-Cogen	0.03	0.11	0.07
Commercial Non-Cogen	0.02	0.02	0.00
Commercial Cogen	0.14	0.13	-0.01
Independent Power Producer Cogen	1.37	1.36	-0.01
Industrial Cogen	0.99	0.90	-0.09
Panel C: By Generation Category, CAISO Data			
Thermal	6.12	8.47	2.35
Imports	5.45	5.77	0.32
Renewables	2.11	2.25	0.14
Large Hydroelectric	2.47	1.58	-0.89
Nuclear	3.07	1.55	-1.51

Note: This table reports the average monthly net electricity generation in California in 2011 and 2012, measured in million MWh. As described in the text, the EIA data describe all U.S. generating facilities with more than one megawatt of capacity. We include generation from all facilities in California. In Panel A, "Other Renewables" includes wood, wood waste, municipal solid waste, and landfill gas. "Other Fossil Fuels" includes petroleum coke, distillate petroleum, waste oil, residual petroleum, and other gases. Panel C describes electricity sold through the California Independent System Operator, including four categories of generation from inside California, and "imports" which includes all electricity coming from out of state.

Table 2: The Effect of the SONGS Closure on the Regional Pattern of Generation

	Average Hourly Change in Net Generation, By Region		
	Southern California (SP26)	Central California (ZP26)	Northern California (NP15)
	(1)	(2)	(3)
	Panel A: All Hours		
Merit-Order Change (MWh)	892	300	944
	(18)	(15)	(18)
Out-of-Merit Change (MWh)	150	20	-140
	(73)	(66)	(79)
	Panel B: Weekday Summer Afternoons		
Merit-Order Change (MWh)	1068	259	822
	(47)	(17)	(39)
Out-of-Merit Change (MWh)	237	76	-260
	(144)	(61)	(119)
	Panel C: High Demand Hours		
Merit-Order Change (MWh)	1207	174	753
	(44)	(30)	(35)
Out-of-Merit Change (MWh)	431	4	-381
	(144)	(57)	(129)
Observations (Hour by Unit)	2,285,140	267,410	1,920,490
Number of Generating Units	94	11	79
Number of Plants	42	5	43
Total Capacity (MW)	15,922	2,887	11,776

Note: This table reports our estimates of the change in generation that resulted from the SONGS closure on January 31, 2012. We report both "merit-order" and "out-of-merit" effects. The merit-order calculation gives the increase in generation at marginal units, assuming 2,150 MWh of lost generation from SONGS. The out-of-merit calculation gives the difference between actual and expected generation, as explained in the text. For all calculations our sample includes hourly observations between April 20, 2010 and January 31, 2013. We exclude generating units that enter or exit during the sample period. As indicated by the column headings, we report estimates for three California regions as defined by the Path-15 and Path-26 transmission interconnections. Panel A reports estimated impacts for all hours. Panel B reports estimates for 2 p.m. to 5 p.m. in months June through September. Panel C reports estimates for hours when total CEMS generation was in the 13th quantile (13,837 MWh) or greater. Standard errors (in parentheses) are clustered by sample month.

Table 3: The Effect of the SONGS Closure on Thermal Generation Costs

	Average Hourly Change in Total Generation Cost, By Region		
	Southern California (SP26)	Central California (ZP26)	Northern California (NP15)
	(1)	(2)	(3)
	Panel A: All Hours		
Merit-Order Change ($000's)	28.6	7.9	26.5
	(0.6)	(0.4)	(0.5)
Out-of-Merit Change ($000's)	7.1	0.5	-3.0
	(2.9)	(1.7)	(2.5)
	Panel B: Weekday Summer Afternoons		
Merit-Order Change ($000's)	41.6	7.5	27.4
	(1.6)	(0.5)	(1.4)
Out-of-Merit Change ($000's)	8.8	1.4	-9.1
	(5.1)	(1.6)	(4.2)
	Panel C: High Demand Hours		
Merit-Order Change ($000's)	49.7	5.7	27.8
	(1.9)	(0.8)	(1.4)
Out-of-Merit Change ($000's)	16.3	-0.5	-14.5
	(4.8)	(1.7)	(4.8)
Observations (Hour by Unit)	2,285,140	267,410	1,920,490
Number of Generating Units	94	11	79
Number of Plants	42	5	43
Total Capacity (MW)	15,922	2,887	11,776

Note: This table reports estimates of the cost of meeting the lost generation from SONGS during the first twelve months following the closure. The format of the table and underlying data are identical to Table 2, but we have used our measures of marginal cost for each generating unit to calculate the change in total generation cost. As we explain in the text, this includes changes in fuel expenditures and other marginal costs, but not capital costs or fixed O&M. Standard errors (in parentheses) are clustered by sample month.

Table 4: The Total Impact of the SONGS Closure

	Total Impact during the Twelve Months following the Closure (Millions of Dollars)
Merit-Order Net Increase in Generation Costs	311 (3.1)
Out-of-Merit Net Increase in Generation Costs	40 (10.7)
Value of Increased Carbon Dioxide Emissions	316 (5.8)

Note: This table reports our estimates of the total economic and environmental impact of the SONGS. The "merit-order net increase" subtracts annual generation costs at SONGS from the merit-order changes to thermal generation costs. The "out-of-merit" increase is the additional increase in generation costs due to transmission constraints and other physical limitations of the grid. As we explain in the text, these generation costs includes changes in fuel expenditures and other marginal costs, but not capital costs or fixed O&M. For comparison, annual fixed O&M at nuclear plants is around $340 million per year. Carbon is valued at $35/ton, as described in the text. All dollar amounts in year 2013 dollars. Standard errors (in parentheses) are clustered by sample month.

Appendix

A1.1 Preliminary Discussion of Potential Confounders

In this Online Appendix we evaluate the potential for confounding factors to influence our results. We are interested, in particular, in potential bias of our main estimates of merit-order and out-of-merit changes. The following sections consider natural gas prices, non-thermal generation, entry and exit of generating units, imports, and demand. Although it is important to go through these potential confounding factors carefully, we end up concluding that overall our estimates are unlikely to be affected by changes in these other market conditions.

Before discussing the specific concerns, it is useful to clarify exactly what we mean by bias. Consider, for example, our estimates of merit-order effects. Conceptually, what we hope to capture with our merit-order estimates is the change in generation from the SONGS closure that would have occurred if there were no transmission constraints or other physical limitations of the grid. Implicitly, we want to hold everything else constant in this calculation so that the estimates reflect the true causal impact of the closure. Our empirical strategy is to build this counterfactual by constructing the unit-level generation curves using data from before the closure, and then to move up these curves by the amount of lost generation. An illustration is provided in Figure A1.

Thus, in some sense, no change to the market in 2012 could "bias" these results. Our merit-order estimates are constructed using pre-closure data only, so they provide predicted changes in generation given the market conditions prior to 2012. An alternative approach for estimation would have been to use post-closure data to construct generation curves, and then to move down these curves by the amount of generation SONGS would have produced had it stayed open. Both approaches build a counterfactual for the SONGS closure, but we prefer our approach because it facilitates a straightforward decomposition of the impact into merit-order and out-of-merit effects (see Figure A1). Since there is no information from 2012 in these estimates, it does not make sense to think about them being biased by anything that happened in 2012. Nonetheless, using pre-closure data to construct our counterfactual raises important questions about changes in market conditions. Put simply, are the market conditions in 2012 so different that our predictions based on pre-closure data are likely to be misleading? The primary objective of the following sections is to work through the different potential confounders. Even though market conditions are constantly changing, we end up concluding that overall our merit-order estimates are unlikely to be meaningfully biased during the twelve months following the closure. As more time passes, conditions become considerably different from the pre-closure period; for this reason we focus on merit-order estimates for the twelve months following the closure.

Conceptually, we want our out-of-merit estimates to reflect the difference between actual generation and the generation that would have occurred if there were no transmission constraints or other physical limitations of the grid. These estimates rely on the same counterfactual constructed for the merit-order estimates, so all the same questions arise about potential confounders.

There is also an additional potential concern for our out-of-merit estimates. The pattern of price differentials make it clear that transmission constraints and/or other physical limitations of the grid were more likely to bind post-closure. This change has been widely attributed to the SONGS closure itself. The pattern of observed prices, both over time, and across California regions tends to support this interpretation. Nonetheless, it is important to consider the possibility there was some other simultaneous change in market conditions that influenced these constraints. We investigate this possibility in the following sections and confirm that changes in confounding factors are unlikely to play much of a role.

A1.2 Changes in Natural Gas Prices

Figure A2 shows that there were large changes in natural gas prices during our sample period. Overall, natural gas prices were around 30% lower in 2012 than they were in 2011. These lower prices reduced the cost of replacing the lost generation from SONGS, relative to what one would have calculated based on 2011 prices. We emphasize this point in describing our results and use 2012 prices when quantifying the cost of increased thermal generation.

In addition, it is natural to ask whether these price changes could somehow bias our estimates of merit-order and out-of-merit changes. In this section we evaluate several potential concerns and, at the same time, discuss closely related potential concerns about changes in the price of permits for Southern California's cap-and-trade program for nitrogen oxides (NOx). Permit prices affect the marginal cost of thermal generation and thus raise very similar questions to changes in natural gas prices, so it makes sense to address both at the same time. Overall, the evidence suggests that our results are unlikely to be meaningfully affected by these price changes.

The main potential concern is changes in the ordering of plants. Our unit-level regressions reflect the ordering of plants along the marginal cost curve. Plants with low heat rates are more efficient, producing large amounts of electricity per unit of fuel input, so these plants operate all the time. Plants with higher heat rates are less efficient, so appear at the high end of the marginal cost curve and operate less frequently. If the changes in natural gas prices affected this ordering, this could bias our estimates of merit-order and out-of-merit effects. We could make mistakes, for example, in reporting which plants met the lost generation from SONGS.

Although this is a reasonable concern, there are several reasons why we would not expect much change in the merit order. First, there is very little coal or other fossil fuels in the California electricity market, and thus little scope for inter-fuel changes in the ordering of plants. Nationwide the decrease in natural gas prices has led to widespread substitution of natural gas for coal (Cullen and Mansur, 2013), but essentially all of this has occured outside the state of California. Second, a large fraction of California generation operates at close to zero marginal cost. This includes nuclear, 'run-of-the-river' hydro, geothermal, wind, and solar. These resources are ahead of natural gas in the queue, regardless of whether natural gas costs $2 or $7 per MMBtu. Third, the ordering of natural gas plants is largely unaffected by natural gas prices. The part of the marginal cost curve made up of by natural gas plants should be thought of, essentially, as an ordering of plants by heat rate. A decrease in natural gas prices reduces the marginal cost of generation for all plants, but the *ordering* is largely unaffected.[23]

We say 'largely unaffected' because marginal cost also depends on NOx emissions and variable operations and maintenance which vary across plants. However, these components are small compared to the cost of fuel so the merit order is almost exactly a monotonic ranking of plants by heat rate. Take NOx prices, for example. Under the RECLAIM program, certain generators in and around Los Angeles must remit permits corresponding to their NOx emissions. As it turns out, however, NOx permit prices were low enough during our sample period that they are unlikely to affect the ordering of plants.[24] In our data, the mean emissions rates for the Los Angeles area plants is 0.4 pounds per MWh (median 0.2 pounds per MWh). The average prices for NOx permits was $2493/ton in 2010, $1612/ton in 2011, and $1180/ton in 2012 (all in 2013 dollars), implying that NOx credit payments make up only a small portion of the plants' marginal costs.[25]

A more subtle concern would be differential changes in natural gas prices between the North and South. However, as can be seen in Figure A2, natural gas prices are quite similar in the North and South during the entire period. This makes sense given the network of existing pipelines as well as available storage, which can smooth out short-run capacity constraints in transmission. Although not visible in the figure, prices in the North decreased from the pre-

[23]Our methodology could still be applied in a setting with multiple fuel types (such as coal and natural gas) or with pipeline congestion leading to regional differences in natural gas prices. Merit-order changes could be identified *within* each fuel type or each region, since that ordering would not be confounded by relative movements in fuel prices. The method would, however, be unable to distinguish cross-region or cross-fuel changes in the merit-order arising from transmission congestion as opposed to relative fuel price changes.

[24]We obtain annual average NOx prices from the Regional Clean Air Incentives Market ("RECLAIM") annual reports for 2006-present. Higher frequency prices are not publicly available. We use the prices of credits traded in the same year as the compliance year.

[25]The mean marginal cost would therefore be less than $0.60 in all three years, compared to wholesale electricity prices that are typically above $30. A small number of units have substantially higher NOx rates; the highest rate we observe is 5 pounds per MWh.

to post-period approximately 2% more than in the South. This is a relatively small change, so we would not expect it to have much impact on the ordering of plants.

A1.3 Changes in Non-Thermal Generation

Between 2011 and 2012 there were also significant changes in electricity generation from hydro and renewables. Perhaps most importantly, 2012 was an unusually bad year for hydroelectric generation. The snowpack in 2012 was only half of the historical average level, and total hydroelectric generation in 2012 was less than 2/3rds generation in the previous year.[26] At the same time, there were also substantial increases in wind and solar generation. Almost 700 megawatts of wind and solar capacity were added in 2012 (CAISO 2013b), resulting in large percentage increases in generation from wind and solar.[27] This section discusses how these changes in non-thermal generation could potentially impact our estimates or affect how the results are interpreted.

As with the changes in natural gas prices, it is worth emphasizing that these changes are exogenous and should not be viewed as being caused by the SONGS closure. Year-to-year variation in hydroelectric generation is driven by idiosyncratic variation in precipitation. And, while new renewables capacity investments do respond to market conditions, it takes at least several years for planning and permitting a new site. The new wind and solar facilities that came online in 2012 were first envisioned in the early 2000s, long before there was any indication of potential safety concerns with SONGS.

It is also important to remember that we measure merit-order effects using *net* system demand. When calculating demand for our unit-level regressions, we start with system-wide but then subtract from it all electricity generated by these non-thermal resources. Figure A3 shows a histogram of this hourly residual demand for each of these two periods, using the same bin width definition as in the regressions. Panel A shows one year of the pre-period and Panel B the post-period. Total generation from CEMS unit clearly shifts up substantially in the post-period to fill in for SONGS. However, the shape of the distribution also changes – because of concurrent shifts, for instance in changes to renewables and hydro generation.

Because these changes to renewables and hydro are exogenous, we do not want our estimated out-of-merit effects to be attributed to changes in these other resources. This exogeneity assumption makes sense for wind, solar, and non-dispatchable hydro, because their marginal cost of operation is near zero – they are always included at the top of the merit order. The same could be said for electricity generation from California's one other nuclear power plant,

[26] For historic snowpack levels see the Snow Water Equivalents data from the Department of Water Resources at http://cdec.water.ca.gov/cdecapp/snowapp/sweq.action. On April 1, 2012, the snowpack was at 54% of the historical April 1 average.

[27] Geothermal and other renewables experienced essentially no change between 2011 and 2012.

Diablo Canyon. Thus changes in generation and/or entry and exit from non-thermal resources will affect the interpretation of our results, but will not introduce bias.

Dispatchable hydroelectric generation is somewhat harder to think about, but it is also unlikely to be affecting our results. Year-to-variation in precipitation determines total hydroelectric generation, but operators have some flexibility as to *when* these resources are utilized. Short-run generation decisions are determined by a complex dynamic optimization problem. Operators respond to current and expected market conditions, trading off between current prices and the shadow value of the remaining water in the reservoir. None of this is particularly problematic for our analysis because operators are presumably behaving similarly both before and after the SONGS closure. Moreover, the generation curves in Figure 5 indicate only a modest amount of intertemporal substitution toward high demand periods. This may be because of the minimum and maximum flow constraints to which hydro operators are subject.

A related question is how changes in non-thermal generation could have changed the likelihood that the transmission constraints were binding, thus indirectly impacting the ordering of thermal resources. This is potentially problematic because we would like to attribute the observed out-of-merit effects to transmission constraints caused by the SONGS outage. Although this is an important consideration, the decrease in hydroelectric generation would have, if anything, made transmission constraints *less* likely to bind. Hydroelectric plants are located primarily in the North,[28] so the decrease in hydroelectric generation in 2012 would have, if anything, actually reduced the need for North-South transmission.

Similarly, the changes in wind and solar generation, while large percentage increases, represent small changes when compared to the entire market. Wind and solar generation statewide increased by 0.17 million, and 0.04 million MWh per month, respectively, in 2012. Total monthly generation in California in 2012 was almost 17 million MWh, so these increases combined represent only about 1% of total generation.

A1.4 Entry and Exit of Thermal Units

From 2010 to 2012, a number of thermal generating units opened or closed, and in this section we discuss the impact of this entry and exit on the interpretation of our estimates. Our main results focus on a balanced panel of units, restricting the sample to those units that were continually in service during our sample period plus Huntington Beach units 3 and 4, which operated for most of this period, but were converted to synchronous condensers in 2013. Excluding units that enter and exit simplifies the analysis and interpretation but also raises two potential concerns. First, our results could be biased if the entry and exit were endogenous to the closure of SONGS. In particular, it would be a causal effect of SONGS that

[28] According to CAISO (2013d), approximately 80% of summer capacity is in the North.

we are failing to capture. Second, for entry and exit that is either endogenous or exogenous, a separate concern is that these changes could somehow have affected transmission congestion. This could then bias our out-of-merit effects.

Entry and exit in 2010 and 2011 is clearly exogenous, since the closure of SONGS was unanticipated. We exclude five units that exited in 2010; these units had accounted for 1 to 2% of generation before their closure. We additionally exclude units that enter in 2010 or 2011, before the SONGS closure was anticipated; these units accounted for 3.5% of generation in 2012. We simply do not have enough pre-period data from these plants to include them in the analysis.

Endogenous entry and exit in 2012 are almost certainly not a concern given the short time horizon. New units take years to plan and permit, and the closure of SONGS was unexpected. To verify this, we examined siting documents from the California Energy Commission for the units that opened in 2012. Altogether, these units accounted for less than 1% of CEMS generation in 2012. Where we were able to locate the siting documents, we found that applications had been filed in 2008 or 2009, long before the SONGS closure. It is possible that these openings may have been accelerated by the SONGS closure, but we are unaware of any specific cases. It is true that in the long run, we would expect endogenous entry, but 2012 is still much too early.[29]

More plausibly, the SONGS outage could have delayed plant exit. To the best of our knowledge, the only such case is the extension of operations at Huntington Beach's units 3 and 4. These two units were expected to retire about the same time that SONGS closed, but remained open in 2012 to provide additional generation and voltage support in Southern California (CAISO 2013b). These units are in our sample, so this generation is reflected in our results. In addition, for these units we estimate an extra year's worth of fixed operations and maintenance costs to be around $4 million.[30] This cost is small in comparison to the generation cost increase caused by the SONGS closure. It is also very small in comparison to the fixed operations and maintenance costs at SONGS itself; this is in part because the two Huntington Beach units are smaller, and in part because fixed O&M costs are much lower at natural gas units than at nuclear units.

Finally, any entry and exit that did occur exogenously, even if it impacted transmission congestion, cannot explain the out-of-merit effects that we estimate. Net entry during the twelve months following the SONGS closure was larger in the North than the South, by

[29] A related possibility is that existing units made capital investments to change their heat rate or capacity. If caused by the SONGS closure, this would be one of the mechanisms through which our effects operate. If not caused by SONGS, it would confound our results only if it affected transmission congestion.

[30] The Cost of Generation Model from CEC (2010) reports an annual fixed O&M cost for California combustion turbine plants of 8.3 $/kW-yr, in 2010 dollars (it does not report a number for steam boilers). We multiplied this by a capacity of 440 MW and translated into current dollars.

approximately 130 MWh on average each hour. Taken by itself, this would have changed congestion in the same direction as the closure of SONGS. However, the difference in net entry between the South and North is smaller than the change in generation from large-scale hydro. As such, the overall impact of these combined changes to generation (from net entry, large-scale hydro, and other renewables) could not have been to exacerbate congestion into Southern California.[31]

A1.5 Imports

Imports make up 30% of total electricity supply in California. In calculating our merit-order effects we have implicitly assumed that none of the lost generation from SONGS is met by out-of-state generation. Whether or not this is a reasonable assumption depends on the impact of the SONGS closure on prices and on the elasticity of supply for imports. Our results suggest that price impacts were likely modest. During most hours equilibrium in the California electricity market occurs along the long inelastic part of the marginal cost curve, so one would not have expected the SONGS closure to have a substantial impact on prices. In addition, during the hours in which equilibrium occurs along the steep part of the marginal cost curve, there was limited available interstate transmission to bring in additional out-of-state supply.

Empirically, the elasticity of supply for imports appears to be relatively low. As shown in Figure 2, imports increase with system demand, but not very much, and most of the increase occurs at relatively low demand quantiles. Above the median system-wide demand, there is essentially no observable increase in imports. Averaging across all hours, imports increase by an average of 519 megawatt hours when total demand increases by 2,150 MWh. This is equivalent to 25% of the lost generation from SONGS. This suggests that we could reduce our merit-order estimates in Panel A of Table 2 by 25%. The regional pattern of generation impacts would still be similar, but all of the estimates would only be about three-quarters as large. For the cost estimates, however, we do not expect much of an adjustment needs to be made. Since the in-state generation marginal cost curve is quite elastic in most hours, the cost of out-of-state generation much have been close to the marginal cost of the in-state generation. As a result, the cost estimates we report in the paper should be close to the true change in total cost accounting for imports.

Interestingly, the change in imports during weekday summer afternoons and high demand hours was much lower. During weekday summer afternoons, imports in 2012 increased on average by only 90 megawatt hours, and during high demand hours the increase was less

[31] For this calculation, we assume that 80% of the fall in hydro generation was from Northern resources, based on the capacity data in CAISO (2013d). We also make the conservative assumption that the entire increase in solar and wind generation was from Northern resources.

than 10 megawatt hours. This is consistent with interstate transmission constraints or other physical limitations of the grid preventing larger increases in imports during these hours. Alternatively, it could simply reflect the fact that demand is correlated across states, i.e. it tends to be hot in Nevada and California at the same time, and so the elasticity of supply for imports becomes very inelastic in these periods.

From the perspective of interpreting our results it doesn't particularly matter *why* imports are not responding more. This lack of responsiveness in high demand hours means that the estimates in Panels B and C of Table 4 are approximately correct. Incorporating imports would reduce our estimates in these panels by only 4% and 1%, respectively, reflecting the relatively small portion of the lost generation from SONGS that appears to have been met with imports.

A1.6 Electricity Demand

Statewide demand for electricity was slightly higher in 2012 than 2011 due to warm weather. We calculate our merit-order effects using the distribution of system-wide demand in 2012, so our estimates reflect this higher overall level of demand. Hence, there is no sense in which this aggregate change in electricity demand is biasing our estimates. Still, in the paper, we would like to attribute the increase in transmission constraints to the SONGS closure, so it would be worth knowing if the changes in electricity demand are large enough to provide an alternative explanation.

Had SONGS closed during a cooler year, it would have been less expensive to meet the lost generation, and transmission constraints would have been less binding. While this is undoubtedly true, the same could be said about hydroelectric generation, natural gas prices, and other factors. Throughout the analysis we have tried where possible to have our estimates reflect actual market conditions in 2012.

A related question is how to think about demand response. Implicitly, our analysis assumes that electricity demand is perfectly inelastic. We calculate our merit-order effects by moving along the generation curves by 2,150 MWhs, the entire lost generation from SONGS. This assumes that demand is perfectly inelastic. Although this assumption is common in the literature, it is obviously not exactly right. Although the vast majority of customers do not face real-time prices, retail electricity prices do respond month-to-month to change in generation costs. Moreover, there are some industrial customers who face prices that update more frequently. The size of the demand response depends on how much prices changed and the price elasticity of demand. The SONGS closure shifts the marginal cost curve to the left, increasing prices. Our results suggest, however, that in the vast majority of hours this price impact would have been fairly modest, because demand was crossing a fairly elastic portion of

the marginal cost curve. Moreover, most estimates of the price elasticity of demand[32] suggest that even in the medium-term, demand is not very elastic.[33] Thus evaluating the change in supply required to make up the entire 2,150 MWhs of lost generation is likely a very good approximation.

A more subtle concern is whether differential changes in demand across region could have impacted transmission constraints. To evaluate this, we obtained hourly demand for three geographic regions within California, corresponding closely to the Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric service territories (the former in the North, and the latter two in the South). In Figure A4, we show the total weekly quantity demanded for all three regions across time. While not large, there does appear to be a divergence in the summer of 2012 between the PG&E and SCE quantities, reflecting a warmer than average summer in the South. However, in Figure A5, we show preliminary evidence that this is unlikely to explain much of the price difference we see in the post-period. This graph plots the price difference between the SP26 and NP15 pricing regions, as well as the demand difference between the South (SCE plus SDG&E) and the North (PG&E). While the demand difference between the North and South increased in late 2012, the price difference increased much sooner and persisted much longer.

To more formally address the concern that our out-of-merit results could have been driven by the changes in demand, we examined results from an alternative specification in which we estimate equation (1) conditioning on the demand *difference* between North and South. Specifically, we calculate the difference between South (SCE plus SDG&E) and North (PG&E), then construct a series of equal-width bins. These bins are interacted with the demand bins in the unit-level generation regressions. The merit-order results (available upon request) are qualitatively similar to those in Table 2. The point estimates of the out-of-merit results are generally around 10% smaller than in Table 2, although they are not statistically different. This may indicate that a small portion of the congestion was attributable to the difference in demand.

[32] Ito (2014), for example, finds a price elasticity of less than -0.10 with respect to retail prices for a sample of California households.

[33] There are also explicit "demand response" programs operated by the three California investor-owned utilities. The use of these programs increased between 2011 and 2012, but from a very low baseline level. Total estimated demand reductions from of all California demand response programs in 2012 was 25,882 megawatt hours (CAISO 2013b, p. 34). This is less than 0.01 percent of total electricity in the market, and equivalent to only 12 *hours* of generation from SONGS. Moreover, there are serious challenges with these programs that limit CAISO's ability to effectively target modest resources to hours and locations when and where they would be most valuable (CAISO 2013b, pp. 35–37).

A1.7 Placebo Tests

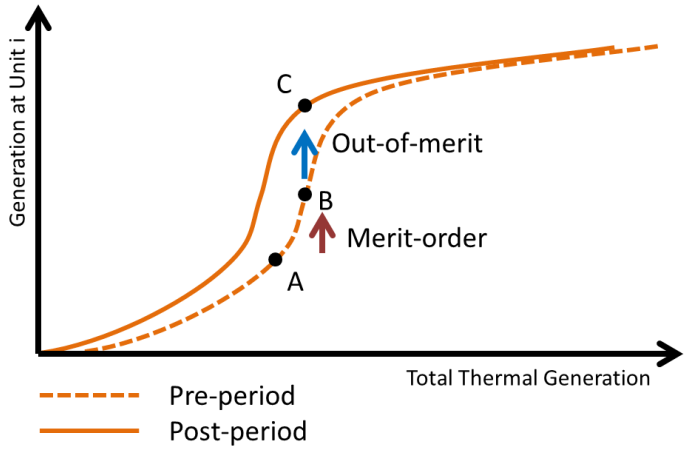
To provide further evidence that the observed out-of-merit effects are unusual, and not driven by idiosyncratic unobservables, we next provide a series of placebo tests. We repeat our analysis six times, estimating the model as if SONGS had closed in different years (2006, 2007, ... and 2011). Figure A6 shows the out-of-merit changes for each placebo regression, with separate results (as in our main analysis) for all hours, weekday summer afternoons, and high demand hours.

The figure shows that some of the estimated out-of-merit effects from other years are similar in size to the estimates for 2012. In 2007, for instance, the South saw positive out-of-merit changes, whereas the North saw negative changes. However, the results for 2012 differ more dramatically from the placebo results when one accounts for the unusual behavior at AES-owned facilities. In Figure A7, we again show six placebo tests, but based on estimates from a sample that excludes AES. In these results, the 2012 large positive changes in the South and large negative changes in the North are more apparent than in the previous figure.

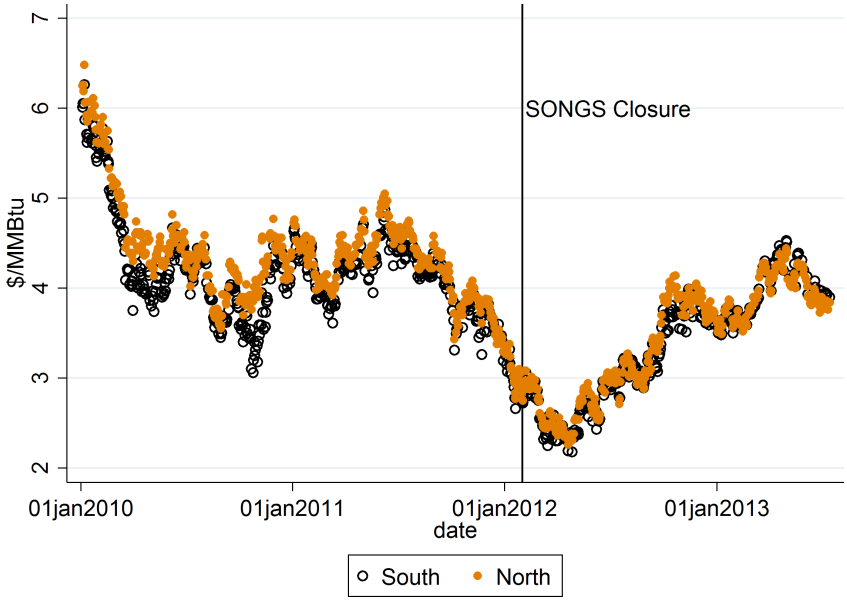
Moreover, closer inspection of the out-of-merit results in other years shows that they are largely driven by extended outages at single plants, rather than by correlated changes across plants. To demonstrate this, Figure A8 shows a series of additional statistics from these placebo tests. In particular, we calculate the standard deviation, skewness, and kurtosis of the unit-level changes. For years with the largest out-of-merit changes (especially 2007 and 2009), the presence of outliers is clear in these diagnostics. These years have higher standard deviations, skewness (in absolute terms), and kurtosis than our main sample, indicating the presence of outliers.

We also calculate out-of-merit costs for each sample. Our estimate of the cost associated with transmission constraints and other physical limitations of the grid following the SONGS closure is $40 million per year. This estimate is higher than all six placebo cost estimates, but in some placebo samples the estimate is close in magnitude to $40 million. Overall, the placebo test results indicate that the pattern of generation and cost results we see in 2012 is indeed unusual.

Appendix Figure A1: Merit-Order and Out-of-Merit Effects

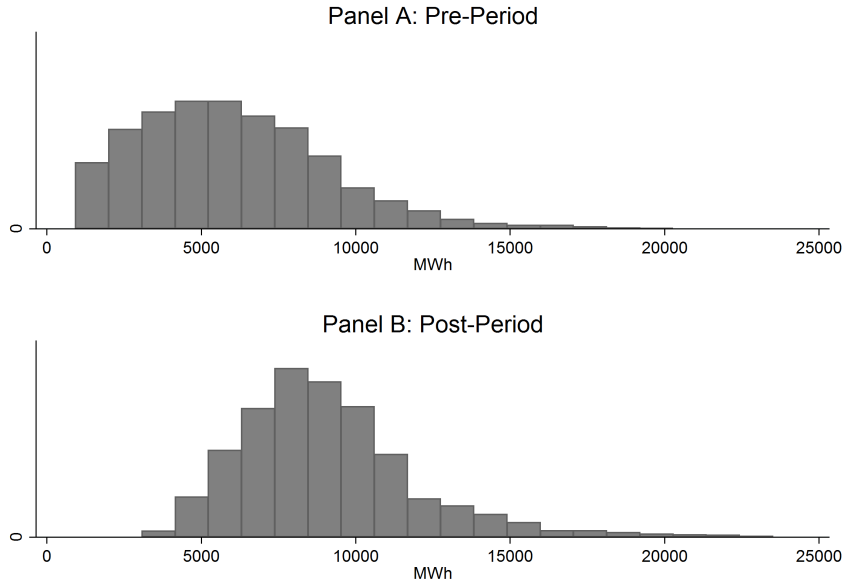


Appendix Figure A2: Natural Gas Prices, by Region



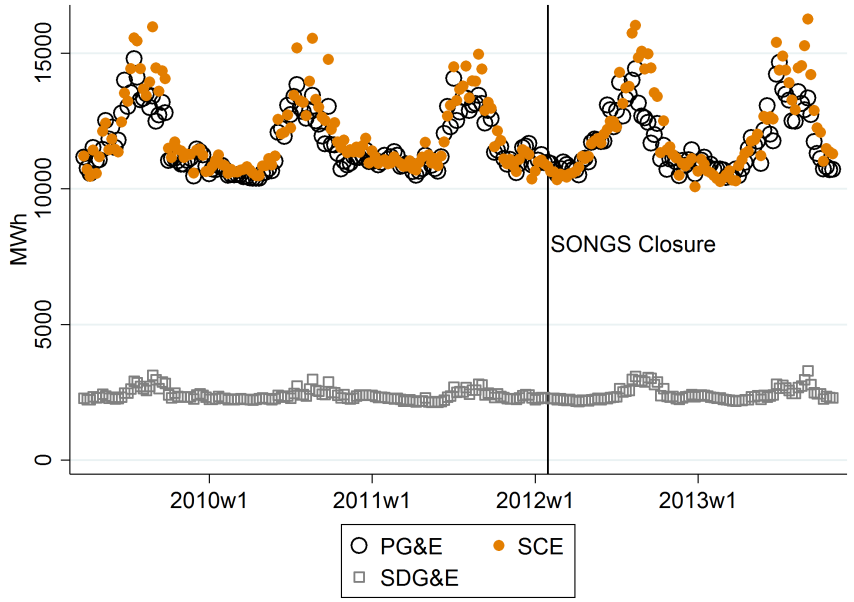
Note: This figure plots daily natural gas prices, in $/mmbtu, for Northern California (PG&E citygate) versus Southern California (SCG citygate). Data are from Platts Gas Daily.

Appendix Figure A3: Histogram of Hourly Total Generation



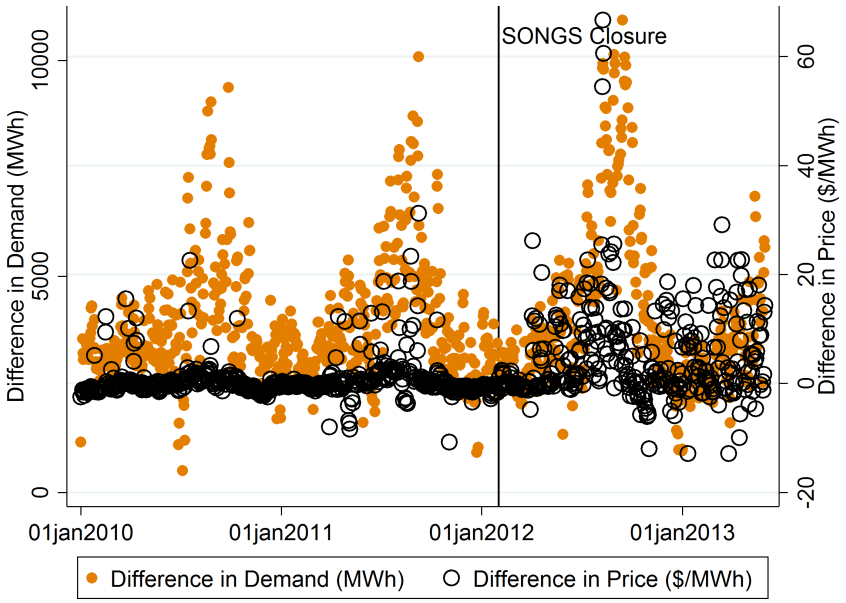
Note: This figure shows histograms of total hourly generation from CEMS units in the year leading up to the SONGS closure (Panel A) and in the year following the closure (Panel B). The shift to the right in Panel B reflects both the closure of SONGS and concurrent changes in non-thermal generation (especially hydro) and demand.

Appendix Figure A4: Regional Demand



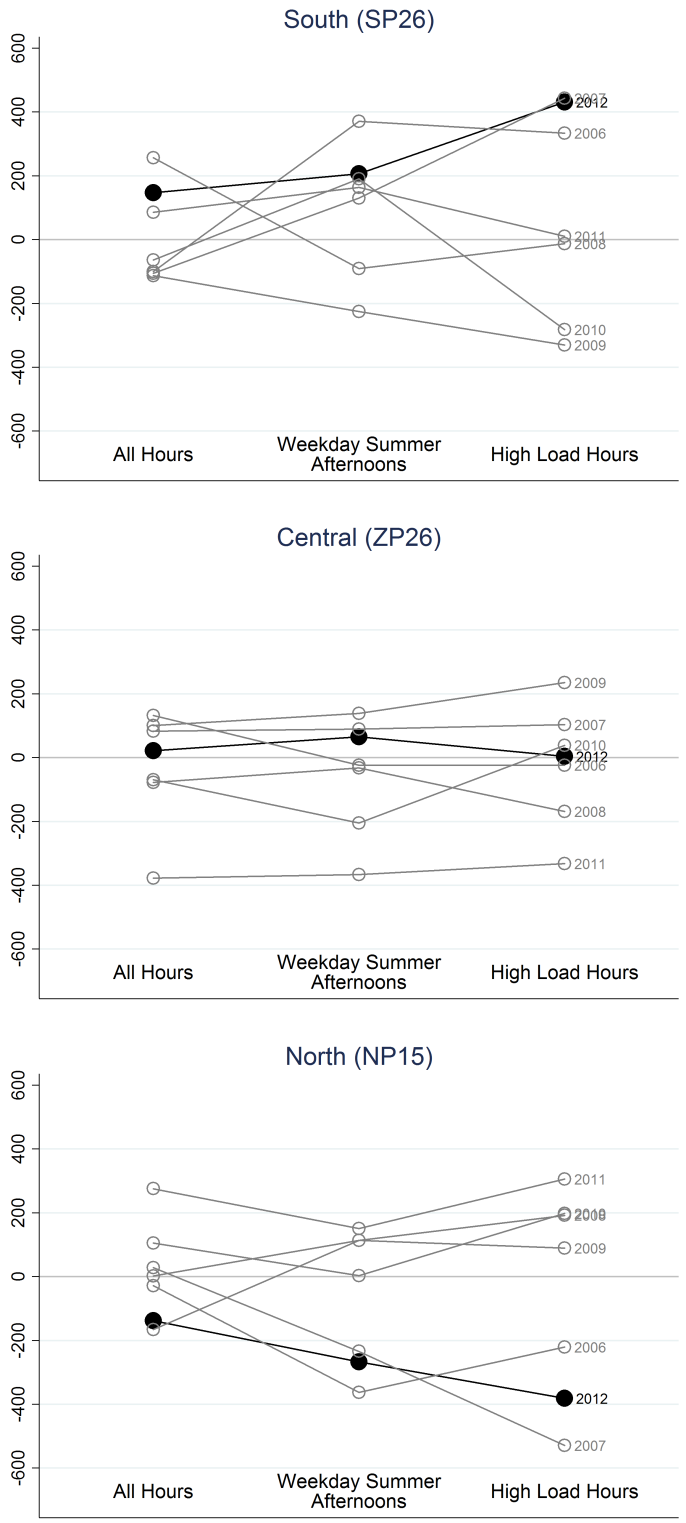
Note: This figure plots average hourly quantity demanded by week for the three California investor-owned utilities. The vertical line shows the week the second SONGS unit went down. PG&E is roughly the Northern half of the state, SCE is the Southern half excluding the San Diego area, and SDG&E is the San Diego area.

Appendix Figure A5: Regional Demand and Price Differentials



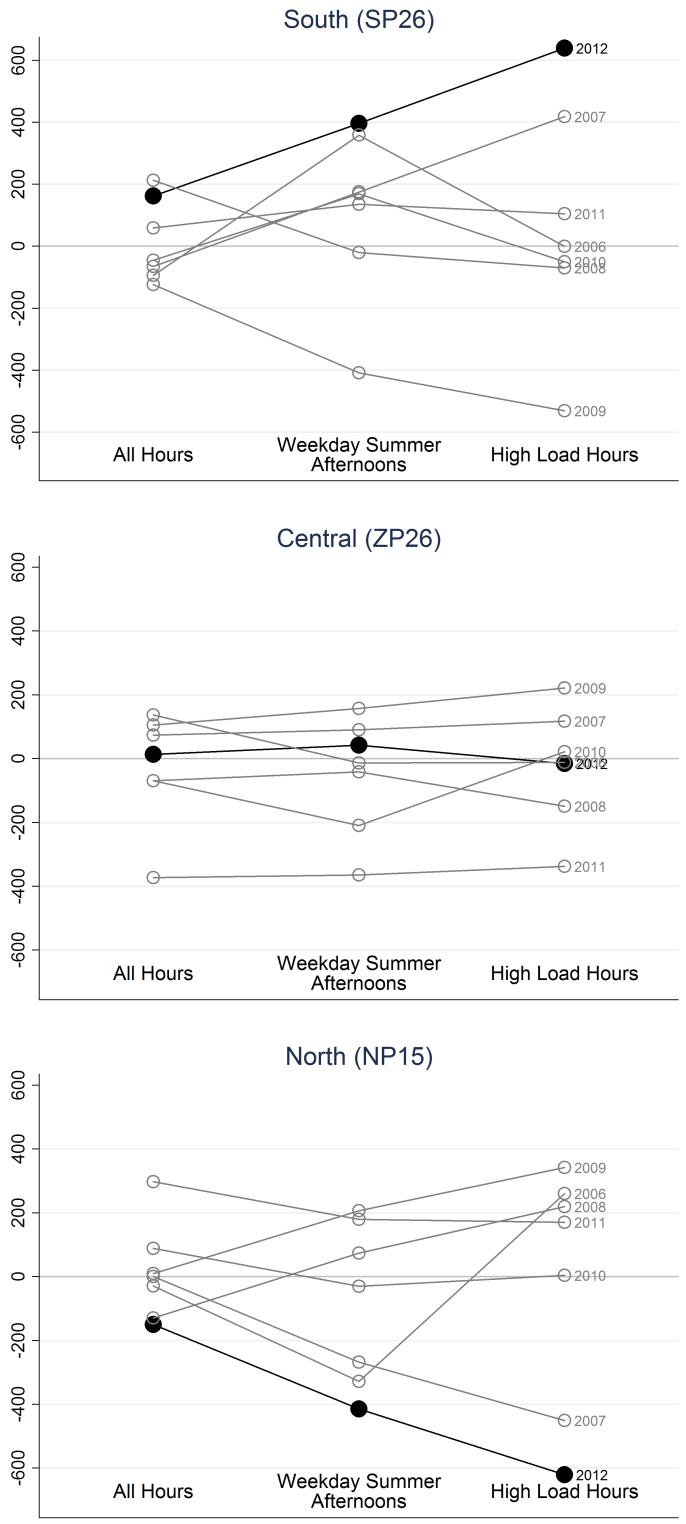
Note: This figure plots quantity demanded and price differentials at 3 pm daily between January 2009 and September 2013. Weekends are excluded. The vertical line shows the day the second SONGS unit went down (February 1, 2012).

Appendix Figure A6: Out-of-Merit Changes, by Year



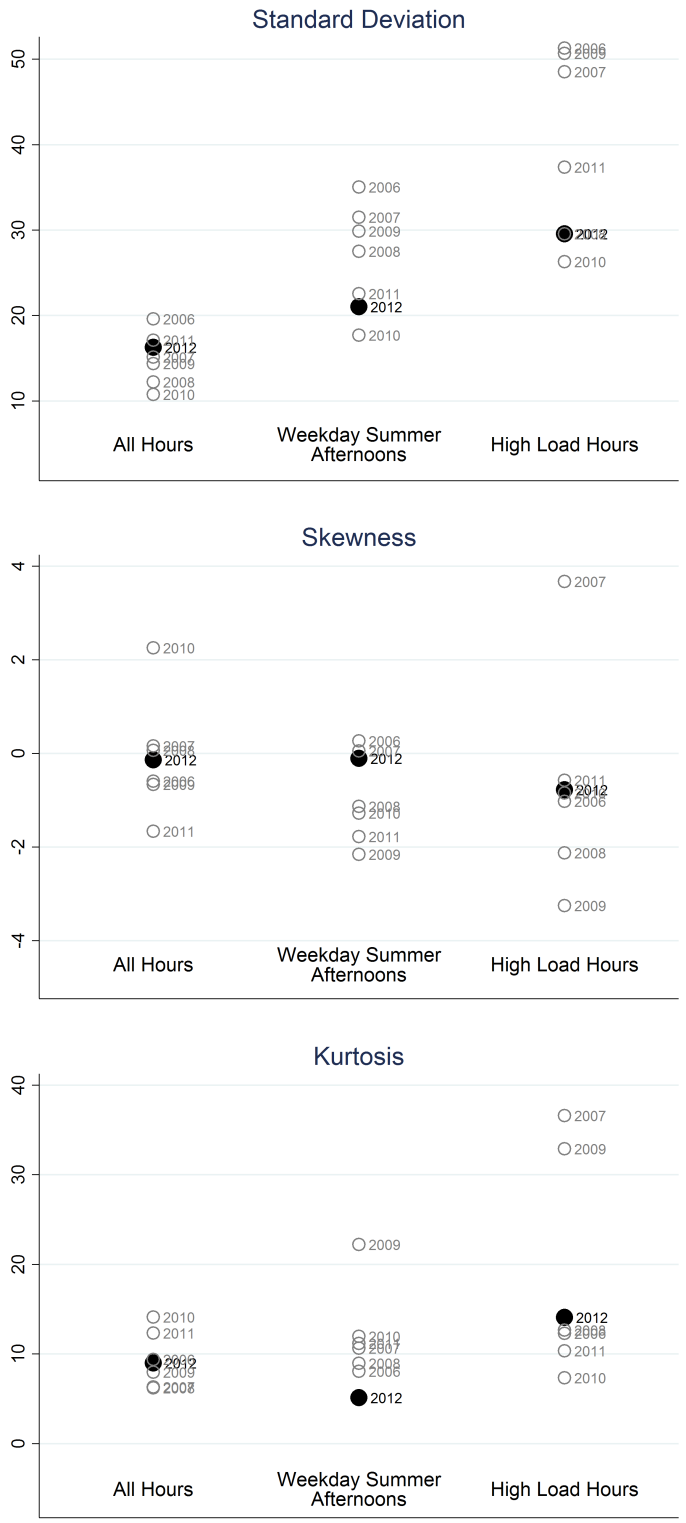
Note: These figures show out-of-merit estimates for the main period of interest (2012, in black) compared to other years for which we have data (hollow grey circles).

Appendix Figure A7: Out-of-Merit Changes, without AES, by Year



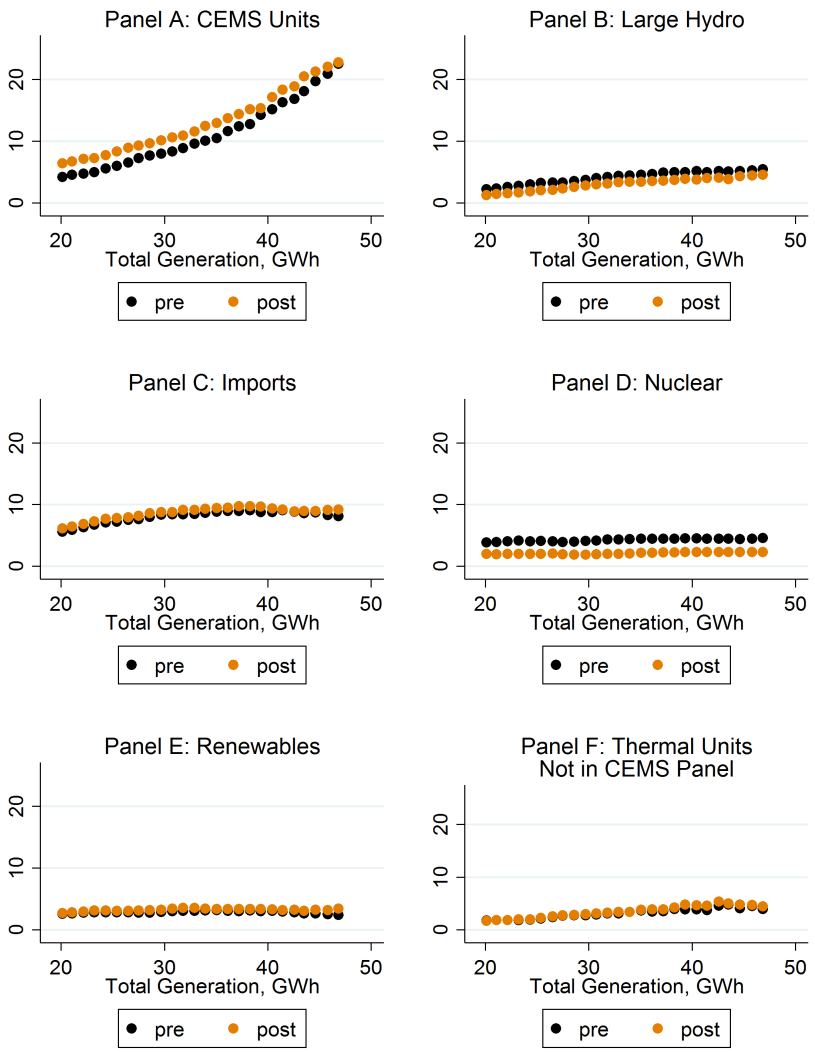
Note: These figures show out-of-merit effects based on estimates from a sample that excludes AES plants for the main period of interest (2012, in black) compared to other years for which we have data (hollow grey circles).

Appendix Figure A8: Unit-Level Diagnostics, by Year



Note: These figures show unit-level diagnostics on the out-of-merit estimates, for the main sample of interest (2012, in black) compared to other years for which we have data (hollow grey circles).

Appendix Figure A9: Generation Regressions by Category



Note: This figure was constructed in the same way as Figure 2 in the main text, but using data from both the pre-period and the post-period. The x-axis shows the quantile of total generation from all sources and the y-axis shows the average generation, in MWh, for that category of generation.

Appendix Table A1: California Electricity Generation By Source, 2011

Category	Subcategory	Percentage
Fossil Fuels	Natural Gas	44.3
	Coal	1.0
	Other Fossil Fuels	1.7
	Total	**47.0**
Nuclear	San Onofre	9.0
	Diablo Canyon	9.2
	Total	**18.3**
Renewables	Hydroelectric	21.1
	Geothermal	6.3
	Wind	3.9
	Solar (PV and Thermal)	0.4
	Other Renewables	3.0
	Total	**34.7**
Total		**100.0**

Note: These data come from the U.S. Department of Energy *Power Plant Operations Report*, which reports net generation from all electric generating plants larger than one megawatt. We include all facilities operating in California. "Other Fossil Fuels" includes petroleum coke, distillate petroleum, waste oil, residual petroleum, and other gases. "Other Renewables" includes wood, wood waste, municipal solid waste, and landfill gas.

Appendix Table A2: Largest Plants not in CEMS

Plant Name	Operator	Sector	Prime Mover	County	Fuels	Million MWh in 2011	Million MWh in 2012	Summer Capacity, MW	Capacity Factor, 2011	Vintage
				Panel A: Non-Cogen Natural Gas Plants						
Humboldt Bay	PG&E	Utility	Internal Combust.	Humboldt	Natural Gas, Petroleum	0.5	0.4	167	0.32	1956*
Wheelabrator Shasta	Wheelabrator Environmental Systems	IPP	Steam Turbine	Shasta	Wood Waste	0.4	0.4	60	0.74	1987
Desert View Power	Desert View Power Inc	IPP	Steam Turbine	Riverside	Wood Waste, Nat. Gas, Tires	0.3	0.3	47	0.83	1991
SEGS IX	FPL	IPP	Steam Turbine	San Bernardino	Solar, Natural Gas	0.2	0.2	88	0.29	1990
SEGS VIII	FPL	IPP	Steam Turbine	San Bernardino	Solar, Natural Gas	0.2	0.2	88	0.28	1989
				Panel B: Cogen and Industrial Natural Gas Plants						
Watson Cogeneration	ARCO Products Co-Watson	Industrial	Combined cycle	Los Angeles	Nat. Gas, Other Gases, Waste Oil	3.0	3.1	398	0.86	1987
Crockett Cogen Project	Crockett Cogeneration	IPP Cogen	Combined cycle	Contra Costa	Natural Gas	1.8	1.7	247	0.84	1995
Sycamore Cogeneration	Sycamore Cogeneration Co	IPP Cogen	Gas turbine	Kern	Natural Gas	1.5	1.4	300	0.57	1987
Midway Sunset Cogen	Midway-Sunset Cogeneration Co	Industrial	Gas turbine	Kern	Natural Gas	1.4	1.4	219	0.72	1989
Kern River Cogeneration	Kern River Cogeneration Co	IPP Cogen	Gas turbine	Kern	Natural Gas	1.3	1.3	288	0.50	1985
				Panel C: Other Plants						
Diablo Canyon	PG&E	Utility	Steam Turbine	San Luis Obispo	Nuclear	18.6	17.7	2240	0.95	1985
San Onofre	SCE	Utility	Steam Turbine	San Diego	Nuclear	18.1	0.8	2150	0.96	1983
Geysers Unit 5-20	Geysers Power Co LLC	IPP	Steam Turbine	Sonoma	Geothermal	4.7	4.8	770	0.70	1971
Shasta	U S Bureau of Reclamation	Utility	Hydro	Shasta	Hydro	2.4	1.8	714	0.38	1944
Edward C Hyatt	CA Dept. of Water Resources	Utility	Hydro	Butte	Hydro	1.9	1.4	743	0.30	1968

Note: These data come from the U.S. Department of Energy *Power Plant Operations Report* and *Annual Electric Generator Report*. The table describes 2011 net generation for plants operating in California. "Largest" is defined according to net generation reported to EIA in 2011. Vintage refers to the year the plant started commercial operation. *Humboldt Bay was in CEMS until 2010 but dropped out after that, when the all of the plant's combustion turbine and steam boiler units were replaced with reciprocating engine generators.

Appendix Table A3: Most Affected Plants, All Hours

Rank	Plant Name	Owner	Plant Type	Zone	Marginal Cost ($ per MWh)	Capacity (Megawatts)	Merit-Order Change (MWhs)	Out-of-Merit Change (MWhs)
			Panel A. Merit-Order Increases, Top Five					
1	Moss Landing	Dynegy	Comb Cyc / Boiler	NP15	27/27/27/27/37/37	2541	227	59
2	La Paloma	La Paloma Gen Co, LLC	Comb Cyc	ZP26	26/26/26/26	1066	168	100
3	Pastoria	Calpine	Comb Cyc	SP15	25/26/26	764	142	-37
4	Delta	Calpine	Comb Cyc	NP15	26/27/27	896	126	25
5	Mountainview	SCE	Comb Cyc	SP15	25/26/26/26	1068	126	3
			Panel B. Out-of-Merit Increases, Top Five					
1	Otay Mesa	Calpine	Comb Cyc	SP15	26/26	596	54	143
2	La Paloma	La Paloma Gen Co, LLC	Comb Cyc	ZP26	26/26/26/26	1066	168	100
3	Cabrillo I Encina	NRG	Boiler	SP15	41/41/42/44/44	954	23	87
4	High Desert	Tenaska	Comb Cyc	SP15	39/39/40	492	91	82
5	Moss Landing	Dynegy	Comb Cyc / Boiler	NP15	27/27/27/27/37/37	2541	227	59
			Panel C. Out-of-Merit Decreases, Top Five					
1	Sunrise	EME† and ChevronTexaco	Comb Cyc	ZP26	25/25	577	101	-114
2	Inland Empire	General Electric	Comb Cyc	SP15	24/25	752	61	-111
3	Calpine Sutter	Calpine	Comb Cyc	NP15	25/26	564	101	-94
4	Gateway	PG&E	Comb Cyc	NP15	27/27	590	84	-72
5	Cosumnes	SMUD	Comb Cyc	NP15	26/26	523	41	-41

Note: The regressions for this table are identical to those in Table 2, but at the plant level. Owner and plant type data are from CEMS documentation, cross-checked against industry sources. The zones are as follows: NP15: Northern California, ZP26: Central California, and SP26: Southern California. Marginal cost numbers are from authors' calculations, described in the text. Capacity in MW is the maximum observed capacity in our sample. †EME refers to Edison Mission Energy.

Appendix Table A4: Most Affected Plants, Weekday Summer Afternoons

Rank	Plant Name	Owner	Plant Type	Zone	Marginal Cost ($ per MWh)	Capacity (Megawatts)	Merit-Order Change (MWhs)	Out-of-Merit Change (MWhs)
			Panel A. Merit-Order Increases, Top Five					
1	Moss Landing	Dynegy	Comb Cyc / Boiler	NP15	27/27/27/27/37/37	2541	236	43
2	AES Alamitos	AES	Boiler	SP15	41/41/42/43/46/47	1934	181	-213
3	La Paloma	La Paloma Gen Co, LLC	Comb Cyc	ZP26	26/26/26/26	1066	152	125
4	Cabrillo I Encina	NRG	Boiler	SP15	41/41/42/44/44	954	89	118
5	AES Redondo	AES	Boiler	SP15	40/444/55/64	1348	88	-67
			Panel B. Out-of-Merit Increases, Top Five					
1	Coolwater	NRG	Comb Cyc / Boiler	SP15	36/38/38/38/41/42	636	30	158
2	La Paloma	La Paloma Gen Co, LLC	Comb Cyc	ZP26	26/26/26/26	1066	152	125
3	Cabrillo I Encina	NRG	Boiler	SP15	41/41/42/44/44	954	89	118
4	Otay Mesa	Calpine	Comb Cyc	SP15	26/26	596	54	98
5	Elk Hills	Occidental Petroleum	Comb Cyc	ZP26	26/27	548	11	86
			Panel C. Out-of-Merit Decreases, Top Five					
1	AES Alamitos	AES	Boiler	SP15	41/41/42/43/46/47	1934	181	-213
2	Panoche	Energy Investors Fund	Combust Turbine	NP15	35/35/35/35	412	54	-105
3	Calpine Sutter	Calpine	Comb Cyc	NP15	25/26	564	60	-94
4	Los Esteros Critical	Calpine	Combust Turbine	NP15	37/37/37/38	186	28	-80
5	Sunrise	EME† and ChevronTexaco	Comb Cyc	ZP26	25/25	577	25	-76

Note: The regressions for this table are identical to those in Table 2, but at the plant level. Owner and plant type data are from CEMS documentation, cross-checked against industry sources. The zones are as follows: NP15: Northern California, ZP26: Central California, and SP26: Southern California. Marginal cost numbers are from authors' calculations, described in the text. Capacity in MW is the maximum observed capacity in the CEMS data. Weekday summer afternoons include the hours 2 p.m. to 5 p.m. in months June through September. †EME refers to Edison Mission Energy.

Appendix Table A5: Most Affected Plants, High Demand Hours

Rank	Plant Name	Owner	Plant Type	Zone	Marginal Cost ($ per MWh)	Capacity (Megawatts)	Merit-Order Change (MWhs)	Out-of-Merit Change (MWhs)
			Panel A. Merit-Order Increases, Top Five					
1	Moss Landing	Dynegy	Comb Cyc / Boiler	NP15	27/27/27/27/37/37	2541	251	-62
2	AES Alamitos	AES	Boiler	SP15	41/41/42/43/46/47	1934	238	-196
3	AES Redondo	AES	Boiler	SP15	40/44/55/64	1348	130	-122
4	El Segundo	NRG	Boiler	SP15	41/42	658	130	113
5	Cabrillo I Encina	NRG	Boiler	SP15	41/41/42/44/44	954	124	154
			Panel B. Out-of-Merit Increases, Top Five					
1	Coolwater	NRG	Comb Cyc / Boiler	SP15	36/38/38/38/41/42	636	33	257
2	Cabrillo I Encina	NRG	Boiler	SP15	41/41/42/44/44	954	124	154
3	Otay Mesa	Calpine	Comb Cyc	SP15	26/26	596	10	117
4	El Segundo	NRG	Boiler	SP15	41/42	658	130	113
5	Ormond Beach	NRG	Boiler	SP15	40/41	1490	98	108
			Panel C. Out-of-Merit Decreases, Top Five					
1	AES Alamitos	AES	Boiler	SP15	41/41/42/43/46/47	1934	238	-196
2	AES Redondo	AES	Boiler	SP15	40/44/55/64	1348	130	-122
3	Panoche	Energy Investors Fund	Combust Turbine	NP15	35/35/35/35	412	53	-116
4	Los Esteros Critical	Calpine	Combust Turbine	NP15	37/37/37/38	186	33	-97
5	Sunrise	EME† and ChevronTexaco	Comb Cyc	ZP26	25/25	577	21	-77

Note: The regressions for this table are identical to those in Table 2, but at the plant level. Owner and plant type data are from CEMS documentation, cross-checked against industry sources. The zones are as follows: NP15: Northern California, ZP26: Central California, and SP26: Southern California. Marginal cost numbers are from authors' calculations, described in the text. Capacity in MW is the maximum observed capacity in our sample. High demand hours are defined as hours when total CEMS generation was in the 13th quantile (greater than 13,837 MWh). †EME refers to Edison Mission Energy.

Appendix Table A6: Separating Alamitos and Redondo

	Average Hourly Change, By Region			
	AES	Southern California, Excluding AES	Central California	Northern California
	(1)	(2)	(3)	(4)
	Panel A: All Hours			
Merit-Order Change (MWh)	110	781	300	944
	(15)	(15)	(15)	(18)
Out-of-Merit Change (MWh)	-32	182	20	-140
	(60)	(53)	(66)	(49)
	Panel B: Weekday Summer Afternoons			
Merit-Order Change (MWh)	339	729	259	822
	(31)	(27)	(17)	(39)
Out-of-Merit Change (MWh)	-311	548	76	-260
	(94)	(105)	(61)	(119)
	Panel C: High Demand Hours			
Merit-Order Change (MWh)	455	752	174	753
	(42)	(34)	(30)	(35)
Out-of-Merit Change (MWh)	-310	742	4	-381
	(127)	(111)	(57)	(129)
Observations (Hour by Unit)	340,340	1,944,800	267,410	1,920,490
Number of Generating Units	14	80	11	79
Number of Plants	3	39	5	43
Total Capacity (MW)	4,167	11,755	2,887	11,776

Note: The format of the table and underlying data are identical to Table 2, but we have separated plants owned by AES from other Southern plants. The three AES plants are Alamitos, Redondo Beach, and Huntington Beach. AES and JPMorgan-Chase had tolling agreements for all three plants.

Appendix Table A7: Including 2013

	Average Hourly Change, By Region		
	Southern California (SP26)	Central California (ZP26)	Northern California (NP15)
	(1)	(2)	(3)
	Panel A: All Hours		
Merit-Order Change in Net Generation (MWh)	883	301	950
	(19)	(17)	(18)
Out-of-Merit Change in Net Generation (MWh)	63	40	-78
	(77)	(70)	(75)
	Panel B: Weekday Summer Afternoons		
Merit-Order Change in Net Generation (MWh)	1037	278	853
	(43)	(15)	(35)
Out-of-Merit Change in Net Generation (MWh)	191	22	-193
	(126)	(77)	(107)
	Panel C: High Demand Hours		
Merit-Order Change in Net Generation (MWh)	1214	183	748
	(41)	(29)	(36)
Out-of-Merit Change in Net Generation (MWh)	390	-15	-348
	(141)	(61)	(131)
Observations	2,565,420	306,735	2,202,915
Number of Generating Units	92	11	79
Number of Plants	42	5	43
Total Capacity Represented (MW)	15,498	2,935	11,782

Note: This table was constructed in the same way as Table 2, except that data were also included for February through June of 2013.