

## Market Impacts of a Nuclear Power Plant Closure<sup>†</sup>

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*Falling revenues and rising costs have put US nuclear plants in financial trouble, and some threaten to close. To understand the potential private and social consequences, we examine the abrupt closure of the San Onofre Nuclear Generating Station (SONGS) in 2012. Using a novel econometric approach, we show that the lost generation from SONGS was met largely by increased in-state natural gas generation. In the twelve months following the closure, natural gas generation costs increased by \$350 million. The closure also created binding transmission constraints, causing short-run inefficiencies and potentially making it more profitable for certain plants to act noncompetitively. (JEL D24, L25, L94, L98, Q42, Q48)*

Nuclear power has historically supplied a substantial portion of electricity—20 percent in the United States and 14 percent worldwide for 2000 to 2012. As recently as 2008, the outlook for the industry was robust, with nuclear plants earning large profits. Since 2009, however, prospects for nuclear power—even at existing facilities—have substantially waned, with the closure of several large facilities and predictions of more closures to come (Energy Information Administration (EIA) 2014). Multiple factors have contributed to the recent closures of nuclear plants. Peak wholesale electricity prices fell around 50 percent in real terms from 2007 to 2012,<sup>1</sup> a result of both falling natural gas prices and stagnant electricity demand. At the same time, costs for nuclear plants have been rising, a combination of rising wages and fuel prices, stricter safety regulations, and the aging of decades-old equipment.

To many observers, low profitability at *existing* nuclear plants is surprising, since the marginal cost of generation is very low at nuclear plants. However, while marginal costs hour-to-hour are low, fixed operating costs (e.g., keeping employees on

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<sup>1</sup>Peak wholesale prices at various hubs for Intercontinental Exchange (ICE) contracts; source: EIA. Prices throughout are deflated to 2013 dollars using the gross domestic product (GDP) deflator.

staff) are high. Total operations and maintenance (O&M) costs at US nuclear plants have increased almost 20 percent in real terms since 2002 and today are more than twice as high as O&M costs at natural gas plants. These higher costs reflect nuclear plants' substantially higher requirements for safety, security, and testing.

In this paper, we use evidence from a nuclear power plant closure to examine the rapidly evolving economics of nuclear power and to assess the potential private and social consequences of plant closures. While in operation, 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<sup>2</sup>—about 8 percent of all electricity generated in the state. SONGS was closed abruptly in February 2012 when workers discovered problems with the plant's steam generators. Although it was not known at the time, SONGS would never operate again.

The first-order effect of the plant's exit was a large inward shift of the electricity supply curve. Like other nuclear power plants, SONGS produced electricity at very low marginal cost. Consequently, the plant was always near the bottom of the supply curve, 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 generating resources with higher marginal cost. We use rich microdata from a variety of sources and a novel econometric method to identify which generating resources increased production. We find that the lost generation from SONGS was met largely by in-state natural gas plants. Bringing these additional plants online cost an average of \$63,000 per hour in the twelve months following the closure. The SONGS closure also had important implications for the environment, increasing carbon dioxide emissions by 9 million tons in the first twelve months. To put this in some perspective, this is the equivalent of putting 2 million additional cars on the road.<sup>3</sup>

There was also a second-order, but not insignificant, additional impact on the market. 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. Prior to the closure, transmission capacity between Northern and Southern California was almost always sufficient, so that wholesale prices equalized in the two regions during the vast majority of hours. However, beginning with the 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.

These second-order effects are reflected in our model as "residuals," measured as deviations from predicted plant behavior. We find that during low demand hours,

<sup>2</sup>US Department of Energy (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.

<sup>3</sup>According to US 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.

the change in generation closely follows predictions based on pre-closure behavior, 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 residual effects: higher cost generating units coming online more than predicted. In high demand hours in 2012, we find that as much as 75 percent of the lost generation was met by plants located in Southern California. On average, the deviations from predicted behavior increased generation costs by \$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.

These residuals also potentially reflect noncompetitive behavior. Tight market conditions make it more profitable for certain firms to exercise market power, and using our model we are able to determine which individual plants changed their behavior the most after the SONGS closure. Because of the transmission constraints, the largest positive residuals are at Southern plants, and the largest negative residuals are at Northern plants. Surprisingly, we also find large negative residuals 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 suggests that our approach may serve as a useful diagnostic tool. Although a large residual effect does not prove that a plant is exercising market power, it is a good indicator of unusual behavior.

Overall, we find that the SONGS closure increased generation costs at other plants by \$350 million during the first twelve months. This is a large change, equivalent to a 13 percent increase in total in-state generation costs. Annual O&M costs at SONGS were about the same amount, so the decision to close probably made sense from a private perspective. Incorporating externalities makes it less clear. Our estimates of the increase in carbon dioxide emissions imply external costs of almost \$320 million during the first twelve months. If plant closure decisions are to be made efficiently, it is important that these environmental impacts be taken into account. Historically, state and federal policies aimed at decreasing carbon emissions have not been designed to incentivize nuclear plants.

Our paper contributes to several strands of the literature. Several recent papers have focused on the prospects for nuclear power, particularly as concern about climate change has increased (Joskow and Parsons 2009, Deutch et al. 2009, Davis 2012, Joskow and Parsons 2012, Linares and Conchado 2013). However, the literature has almost exclusively focused on the outlook for *new* nuclear plants. The decision to enter the market is quite different from the decision to exit. Entry decisions are driven in large part by construction and financing costs, which historically have been very high for nuclear plants. In contrast, because these costs are sunk for existing nuclear plants, exit decisions are driven by wholesale electricity prices and operating expenses. With construction of new nuclear almost completely halted, we argue that exit will be the more policy-relevant margin for the foreseeable future.

Our paper also adds to a small literature on the value of geographic integration in electricity markets (Mansur and White 2012, Birge et al. 2013, Ryan 2014, Wolak

2015). 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 2014), rather than econometric analysis. Our methodology is novel, because it quantifies the impact of transmission constraints 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 general 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.<sup>4</sup>

## I. Background

### A. Economic Outlook for Existing Nuclear Plants

In the United States, electricity generation in 2012 came from coal (37 percent); natural gas (30 percent); nuclear (19 percent); hydro (7 percent); and wind, solar, and other renewables (5 percent).<sup>5</sup> The global generation mix was qualitatively similar: fossil fuels (67 percent); nuclear (11 percent); hydro (17 percent); and wind, solar, and other renewables (5 percent).<sup>6</sup> This mix of technologies reflects marginal and fixed cost considerations, flexibility, and environmental objectives. The lowest marginal cost sources are solar and wind, followed by nuclear, and then by fossil fuel plants. Coal tends to have lower marginal cost than natural gas; but in recent years, falling natural gas prices in North America have pushed some natural gas plants ahead of coal plants in the queue (Cullen and Mansur 2014; Holladay and LaRiviere 2014; Linn, Muehlenbachs, and Wang 2014).

Despite the low marginal cost of nuclear plants, their profitability and long-term viability have eroded substantially since 2009 in the United States (EIA 2014). Four nuclear plants have recently closed: Crystal River, Kewaunee, San Onofre, and Vermont Yankee. Moreover, recent reports have flagged numerous additional plants that are at risk of closing (Navigant Consulting Inc. 2013; UBS 2013, 2014). One report provided the following summary: "Nuclear units, with their high dispatch factors have among the greatest exposure to gas/power price volatility, as they are price takers. In tandem, nuclear generators have continued to see rising fuel and cost structures of late, with no anticipation for this to abate" (UBS 2013). As a result of these concerns, the EIA assumes 6 GW of nuclear retirements by 2019 in the reference case for its 2014 Annual Energy Outlook.

<sup>4</sup>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).

<sup>5</sup>Table 7.2a "Electricity Net Generation: Total (All Sectors)" in EIA (2013).

<sup>6</sup>EIA's International Energy Statistics 2012.

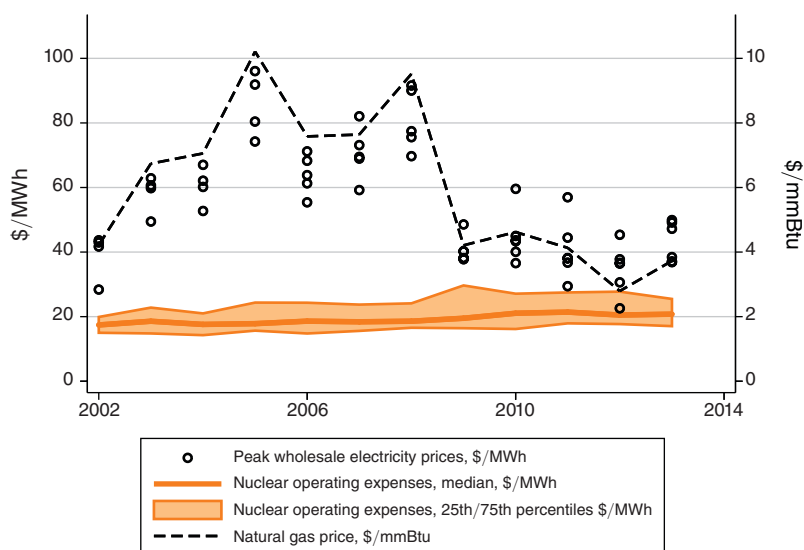


FIGURE 1. DECLINING PROFITABILITY OF US NUCLEAR POWER PLANTS

*Notes:* This figure plots wholesale peak electricity prices in real \$/MWh at various ICE hubs around the country. The dashed black line shows Henry Hub natural gas prices (in \$/mmBtu), the driver of wholesale peak electricity prices. The solid lines show the median, 25th percentile, and 75th percentile operating expenses at US nuclear plants, in real \$/MWh. Electricity and natural gas prices are from EIA; operating expenses are from EUCG, Inc.

Figure 1 describes this erosion of profitability, showing in real terms both rising costs (solid line) and falling wholesale electricity prices (hollow circles, for peak prices). Even during peak hours, nuclear plants are currently earning only modest net revenues. The primary driver has been a dramatic decrease in wholesale electricity prices. This is a direct consequence of the fall in natural gas prices (the dashed line in Figure 1) driven by the shale boom. The advance of technologies for extracting unconventional natural gas caused an almost 50 percent decline in natural gas prices in the United States from 2007 to 2013 (Hausman and Kellogg forthcoming). Natural gas power plants are frequently on the marginal portion of the supply curve, so their marginal costs tend to set wholesale electricity prices. Moreover, marginal costs for natural gas plants are predominantly fuel costs. Accordingly, not only are natural gas plants pushing ahead of coal plants in the supply queue, they are also pushing down wholesale electricity prices.<sup>7</sup> The magnitude of the pass-through, empirically estimated in Linn, Muehlenbachs, and Wang (2014), is determined by the heat rates of marginal plants.

Two additional factors help explain this period of sustained low wholesale electricity prices. First, there has been a rapid rise in renewables capacity. Non-hydro renewables grew by over 250 percent from 2001 to 2013, albeit from a small

<sup>7</sup>The figure plots peak wholesale prices, using annual averages of daily prices for ICE contracts at the MISO (Indiana Hub), PJM (West), CAISO (NP-15), Northwest (Mid-Columbia), CAISO (SP-15), and Southwest (Palo Verde) hubs. The year-to-year variation largely reflects changing natural gas prices. The geographic dispersion reflects transmission constraints in electricity combined with pipeline constraints in natural gas and differences in heat rates at natural gas plants.

baseline. Second, electricity demand has been largely stagnant. While growth averaged almost 4 percent per year from 1970 to 1990, from 2000 to 2014 it averaged less than 1 percent per year,<sup>8</sup> and it is expected to continue to be less than 1 percent per year (EIA 2015). As a result of falling natural gas prices, growing renewables capacity, and stagnant demand, both peak and off-peak electricity prices fell by around 50 percent in real terms from 2007 to 2012.<sup>9</sup>

At the same time that revenues have fallen, multiple factors have contributed to rising costs at nuclear power plants. Costs can be divided into three categories: capital costs, fuel costs, and operating expenses. Capital costs are largely sunk, and therefore not relevant for our analysis. Fuel costs per MWh, however, increased in real terms by 25 percent from 2002 to 2012, concurrent with an increase in uranium prices.<sup>10</sup> Operating expenses have also increased 18 percent in real terms from 2002 to 2012 at the median plant.<sup>11</sup> Part of this increase has come from rising labor costs. According to data from the Bureau of Labor Statistics' *Quarterly Census of Employment and Wages*, average annual salaries in the nuclear electric power generation sector (North American Industry Classification System (NAICS) 221113) increased by 21.5 percent in real terms between 2002 and 2013. Possible additional factors include new safety requirements following Fukushima and the aging of US reactors. In 2014, the age of US nuclear power reactors ranged from 19 to 46 years, and the average age was 35.

Figure 1 shows that operating expenses at US nuclear plants have increased steadily since 2002. This is true whether one looks at the median, twenty-fifth, or seventy-fifth percentile. These expenses include operations and maintenance costs, such as labor costs, but not fuel costs or capital expenditures. A substantial wedge between peak wholesale prices and operating costs can be seen in the early 2000s, but by 2009 the wedge was dramatically shrunk. Moreover, the actual wedge between revenues and costs is even lower than what is shown in this figure. Off-peak wholesale electricity prices are also relevant, and are around 35 percent lower than on-peak prices. Fuel costs also reduce the wedge; in 2012 they were around \$7–\$8 per MWh (source: EIA Table 8.4, and SNL). Unfortunately, we do not have a comprehensive time series of nuclear fuel costs.

Figure 1 makes clear that US nuclear power plants have become much less profitable. Nuclear plants continue to have lower marginal cost than coal and gas plants and thus are still near the bottom of the supply curve. Instead, what has changed is

<sup>8</sup> US DOE/EIA "Table 7.6 Electricity End Use," April 2015.

<sup>9</sup> In addition to the peak prices for ICE contracts available from EIA, we assembled data from SNL Financial from 6 different wholesale hubs: ERCOT (North), New England ISO (Massachusetts Hub), PJM (West), Southwest (Palo Verde), Northwest (Mid-Columbia), and MISO (Illinois Hub). Off-peak prices generally run from about 11 PM to 7 AM, though the exact hours vary across ISO. In both 2007 and 2012, off-peak prices averaged around 65 percent of peak prices.

<sup>10</sup> Source: EIA, "Table 8.4. Average Power Plant Operating Expenses for Major US Investor-Owned Electric Utilities, 2002 through 2012." Data are not available for independent power producers, but fuel costs are presumably similar as all plants purchase fuel assemblies in the same market.

<sup>11</sup> Source: EUCG, Inc. EUCG assembles blinded cost data from all nuclear power plants in the United States for cross-reactor information sharing. These data are not publicly available, but we were provided with summaries by quartiles after making a data request. Other sources of information on operating costs include Federal Energy Regulatory Commission (FERC) and EIA, which only collect data on a subset of plants, or SNL, which extrapolates the FERC data to other plants. The EUCG data, which represent *all* plants, are in line with FERC and SNL summaries.

TABLE 1—FUEL COSTS AND OPERATING EXPENSES  
BY ELECTRIC GENERATING TECHNOLOGY, 2013

	Fuel, \$/MWh	O&M, \$/MWh	Fuel plus O&M, \$/MWh
Nuclear ( $n = 99$ )	8.2	15.8	24.0
Coal ( $n = 1,074$ )	25.2	7.9	33.1
Natural gas combined cycle ( $n = 1,764$ )	32.6	3.9	36.6
Natural gas combustion turbine ( $n = 2,083$ )	41.7	9.4	51.1

*Notes:* Authors' calculations based on data from SNL Financial's "Generation Supply Curve." The table reports mean fuel and operating costs per megawatt hour, weighted by net generation. Means are calculated over all generating units that were operating in the continental United States in 2013.

the ability of hour-to-hour net revenues to cover the fixed costs of keeping a nuclear plant open. Of course, all types of electric-generating facilities must be able to cover their ongoing fixed costs, but this is particularly relevant for nuclear power plants because of their high O&M costs. Table 1 shows fuel and O&M costs at nuclear plants compared to other forms of generation. Nuclear plants have by far the lowest fuel cost. However, O&M costs are \$15.8/MWh at nuclear plants, compared to \$3.9–\$9.4/MWh at fossil fuel plants.<sup>12</sup> Natural gas combined cycle plants, in particular, have O&M costs that are only about one fourth that of nuclear plants.

Although in the table we have expressed O&M costs scaled by generation, this should not in general be thought of as a marginal cost. With O&M, it is difficult to sharply distinguish between fixed and marginal costs; the former consists of costs that allow a plant to remain open, but do not depend on the level of generation produced. These include, for instance, employees whose primary task is safety compliance. In Table 1, we do not attempt to distinguish the two types of O&M. What is most notable, however, is how much higher O&M costs are at nuclear plants relative to coal and natural gas plants. As such, fuel makes up less than 35 percent of operating expenses for nuclear plants, while it makes up over 75 percent at coal and natural gas plants.

The table makes clear that the economics of running a nuclear plant are quite different from the economics of running a coal or natural gas plant. While low fuel costs mean that nuclear plants should be continually operating conditional on being open, high O&M costs mean that even running 365 days per year may not generate enough revenue if wholesale prices are low. These high O&M costs are not sunk in the way that construction costs are; they can be avoided if a plant closes, and indeed you would expect a plant to close when O&M costs exceed expected net revenue.<sup>13</sup>

<sup>12</sup> Average nuclear O&M costs are somewhat higher in EUCG data, but this is largely a function of weighting by generation. The unweighted average O&M costs in the SNL data are \$20.4/MWh for 2013, compared to \$20.8/MWh in the EUCG data.

<sup>13</sup> An additional cost, required by the NRC, is the decommissioning of a site after closure. The NRC requires funds for decommissioning in advance, for instance through a trust fund or other surety method.

### B. *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).<sup>14</sup> 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. This routine refueling outage was scheduled at a time of year when demand was low and was intended to affect only one reactor. In this regard, it was like other planned temporary outages at nuclear plants, which are in general designed to limit disruption to the electricity market.

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” (Metz et al. 2012, p. 4), relating to the possibility of insufficient summer capacity and the possibility of transmission constraints (CAISO 2012; North American Electric Reliability Corporation (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” (Cunningham 2013).

The SONGS closure was abrupt, permanent, and unexpected; this allows us to sharply distinguish between the before and after periods, and thus to identify the effect of the closure. In contrast, in many empirical settings, openings and closings of transmission and generation capacity are both expected and endogenous, so that causal effects are difficult to identify. Moreover, outages at transmission and generating facilities are potentially endogenous, as they are more likely to occur when stress is being put on the system. SONGS is of additional interest because, like many US nuclear power plants, it operated in a deregulated electricity market. In contrast, in states where generation companies are regulated using cost-of-service regulation there is less scope (and less incentive) for companies to exercise market power in response to changes in market conditions.

Finally, the SONGS setting is worth studying because it demonstrates the importance of accounting for transmission congestion. Transmission constraints are a pervasive feature of electricity markets, and they are extremely important because unlike most other goods, electricity cannot be cost-effectively stored. Supply must

<sup>14</sup>SCE is also the majority owner (78 percent). The other owners are San Diego Gas and Electric (20 percent) and the city of Riverside (2 percent).



meet demand at all times, or the frequency in the grid will fall outside of a narrow tolerance band, causing blackouts. With electricity demand highly variable and inelastic, the market clears mostly on the supply side. Geographic integration helps smooth the price volatility that can result.

## II. Data

For this analysis we compiled publicly-available data from a variety of different sources including the US Department of Energy's Energy Information Administration (EIA), the California Independent System Operator (CAISO), and the US Environmental Protection Agency (EPA).

### A. Generation Data from EIA

We first assembled a dataset of annual plant-level electricity generation from the EIA. 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 data at the annual level, relying on the other datasets described below for within-year comparisons.

Table 2 describes California electricity generation in 2011 and 2012. By far the largest source of generation in California is natural gas, with 44 percent of total generation in 2011. The second largest source is hydro, accounting for 21 percent of generation. The two nuclear plants, San Onofre and Diablo Canyon, each contributed approximately 9 percent of total generation in 2011. Finally, geothermal, wind, solar, and other renewables account for about 14 percent of total generation. Additional details are provided in the online Appendix.

SONGS was closed on January 31, 2012, so the columns in Table 2 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 increased 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

TABLE 2—CALIFORNIA ELECTRICITY GENERATION, 2011–2012

	Average monthly generation, million MWh 2011	Average monthly generation, million MWh 2012	Change
<i>Panel A. By generation category, EIA data</i>			
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
<i>Panel B. By type of natural gas plant, EIA data</i>			
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
<i>Panel C. By generation category, CAISO data</i>			
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

*Notes:* This table reports the average monthly net electricity generation in California in 2011 and 2012, measured in million MWh. The EIA data describe all US 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 land-fill 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.

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.

### B. Generation Data from CAISO

To complement the EIA data, we next assembled a database using publicly-available records from CAISO. The CAISO data describe hourly 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 2, 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 it offsets only one fifth of the shortfall experienced from the SONGS closure, and only about one tenth of the combined shortfall from SONGS and the decrease in hydroelectric generation. We examine the role of imports in greater depth in Section IVA, 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.

### *C. 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). 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 (2014); Graff Zivin, Kotchen, and Mansur (2014); Novan (2015). 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. In 2011, these plants represent 30 percent of total generation in California and 62 percent 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, one third of natural gas-fired generation in California is from cogeneration, industrial, and commercial facilities, which are generally not in CEMS. Indeed, generation reported in CEMS in 2011 is 96 percent 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. 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,”

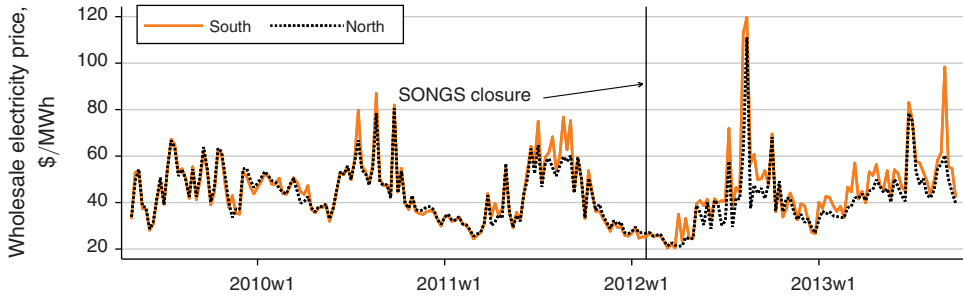


FIGURE 2. EVIDENCE OF INCREASING TRANSMISSION CONSTRAINTS SINCE 2012

*Notes:* This figure was constructed by the authors using data on California wholesale electricity prices from CAISO. The figure plots average weekly prices at 4 PM between May 2009 and September 2013, in 2013 dollars/MWh. Weekends are excluded. The dashed black line is for Northern California (NP15), and the solid line is for Southern California (SP26). The vertical line indicates January 31, 2012, the day the second SONGS unit was shut down.

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 percent of gross generation; details are in the online Appendix.

#### D. 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 2 plots prices in Northern and Southern California in dashed black and solid lines, respectively. We plot prices for 4 PM on weekdays (averaged across the week), a time when transmission constraints are more likely to bind. Before the SONGS closure, prices track each other extremely closely, and the price differential is not statistically significant ( $p$ -value 0.1). After the SONGS closure, prices diverge and the price differential is positive (i.e., South exceeds North) and statistically significant ( $p$ -value  $< 0.01$ ). There are even a few weeks with differentials that exceed 50 percent of the North price. Also, the correlation between Northern and Southern prices falls, from 0.94 in the pre-period to 0.89 in the post-period.

### III. Empirical Strategy and Generation Regressions

The data show a significant increase in natural gas generation between 2011 and 2012. We next ask how much of this increase is due to the SONGS closure, and whether any other generating resources changed production in 2012 as a result of the closure. To answer these questions, we need a model that can tell us which generating units are *marginal* at any point in time. Low-cost generating units operate most hours of the year, regardless of system-wide demand, while higher-cost generating units operate only during relatively high demand hours. System-wide demand

varies substantially hour-to-hour as a function of weather and economic activity, and different units turn on and off across hours to equate supply with demand. We describe this relationship semi-parametrically, using a series of regressions, estimated separately before and after the closure.

We distinguish between two effects: the predicted change in generation associated with the next generating units along the marginal cost curve being brought online; and the residual change in generation associated with a change in the order of the generating units along the supply curve. The predicted effects, which vary from hour to hour, measure a non-marginal shift (arising from the loss of SONGS) in the net demand faced by each generating unit. Residual effects measure differences between actual generation and predicted generation, reflecting transmission constraints and other physical limitations of the grid as well as noncompetitive behavior.

An alternative to our empirical strategy would have been to simulate counterfactuals using an engineering model of the electrical grid combined with a structural model of firm optimization. Although these models have been widely used, 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 addition to congestion between the two main North and South zones, congestion *within* regions is also important. 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).<sup>15</sup> 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.

### A. Generation Regressions by Category

The core of our econometric model is a system of what we call “generation regressions,” which describe the relationship between system-wide demand and generation at individual sources. We estimate these regressions first for broad categories

<sup>15</sup>Bid mitigation is the replacement of submitted bids with default cost-based bids; exceptional dispatch is a manual override of the market optimization algorithm.

of generation and then, in Section IIIB, for individual generating units. For the generation regressions by category the estimating equation takes the following form:

$$(1) \quad \text{generation}_{it} = \sum_b (\gamma_{bi} \cdot 1\{\text{system-wide demand}_t = b\}) + \varepsilon_{it}.$$

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. 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. We have also estimated several alternative models that include fixed effects, such as: hour-of-day effects, month-of-year effects, and 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.

At first glance, this estimating equation would appear to suffer from simultaneity. However, 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, rich seasonal variation in demand driven by lighting and air conditioning. In practice, these exogenous shifts in demand overwhelm cost shocks and 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 indicator variable 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  $\gamma_{bi}$  are equal to the average generation for category  $i$  when system demand is in bin  $b$ . 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.

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  $\gamma_{bi}$  are allowed to differ by generation category, we estimate six separate regressions, one for each category. Figure 3 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 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.

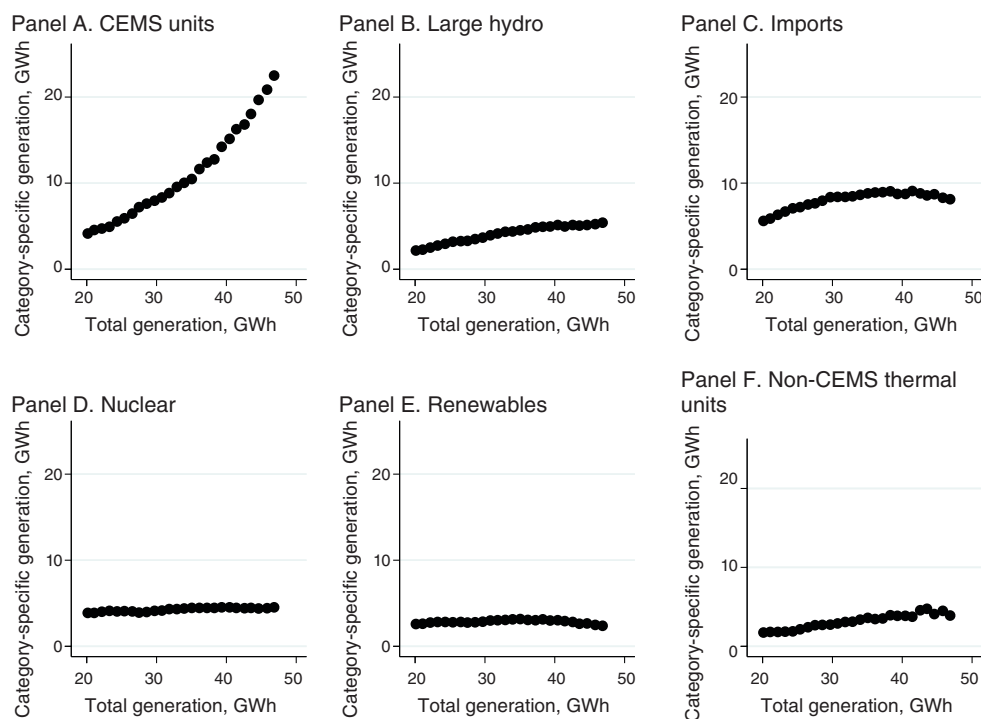


FIGURE 3. GENERATION REGRESSIONS BY CATEGORY

*Notes:* These figures plot the coefficients from six separate regressions. The 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 percent confidence intervals are not shown because they are extremely narrow for all six panels.

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.<sup>16</sup> 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), which emphasizes results from a linear-log specification implying low import responsiveness during high demand hours. Past the median level of demand, imports are essentially flat. As we describe in the online Appendix, this could result from correlated demand across states or from interstate transmission constraints. 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. Thermal units not in the CEMS data (panel F) are also not very responsive, reflecting that they are primarily cogeneration and industrial facilities.

<sup>16</sup>However, hydro operators are subject to minimum and maximum flow constraints.

Comparing these results with the aggregate pattern of generation in Table 2, both show 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 3, the year-to-year variation is entirely exogenous—it depends on total precipitation.

### B. 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  $j$ ,

$$(2) \text{ generation}_{jt} = \sum_b (\alpha_{bj} \cdot 1\{\text{system-wide thermal generation}_t = b\}) + e_{jt}.$$

The right-hand side bins, again indexed by  $b$ , are now defined over total generation by all the CEMS units in our balanced sample. We use this rather than total system demand because we want to identify the ordering within the category of natural gas units, and because we want to attribute changes from the pre-period to the post-period only to the SONGS outage, not to concurrent changes to renewables, hydro, or demand. Simultaneity is again not a concern: system-wide thermal generation is driven by exogenous shifts in electricity demand, which is both highly inelastic and highly variable across hours, and by idiosyncratic fluctuations in generation from renewables, hydro, and other non-CEMS categories of generation. We further examine this exogeneity assumption in the online Appendix.

We estimate these unit-level generation regressions using two separate samples corresponding to before and after the SONGS closure. Observing behavior before the closure allows us to construct a counterfactual for what would have occurred if SONGS had not closed. 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. 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 January 2013.<sup>17</sup> We explore entry and exit

<sup>17</sup>We also drop four generating units, which are owned by the Los Angeles Department of Water and Power (LADWP). 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.



in the online Appendix, finding 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 4. We show twelve plants: the four largest plants 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 to identify 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.<sup>18</sup>

When estimating the standard errors, we cluster by sample month to allow for arbitrary 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.

### C. Predicted and Residual Effects

We thus have a set of coefficients  $\alpha$  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 using what we call “predicted” and “residual” effects. For each generating unit, we define the predicted change in generation caused by the SONGS closure as follows: maintaining the coefficients from the pre-period, while requiring an additional 2,150 megawatt hours of generation to fill the SONGS gap. This is akin to assuming that the ranking of marginal costs did not change. Recalling that the width of each bin is equal to 1,075 megawatt hours, the predicted 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 equivalent to moving up two bins:

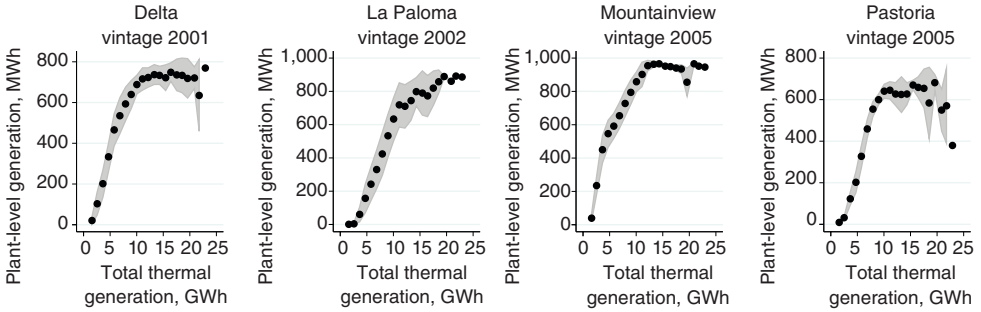
$$(3) \quad \sum_{b>2} \sum_{j \in J} (\alpha_{bj}^{pre} - \alpha_{b-2,j}^{pre}) \cdot \theta_b^{post},$$

where  $\theta_b^{post}$  is the fraction of hours that system-wide demand was in bin  $b$  during the post-period.<sup>19</sup>

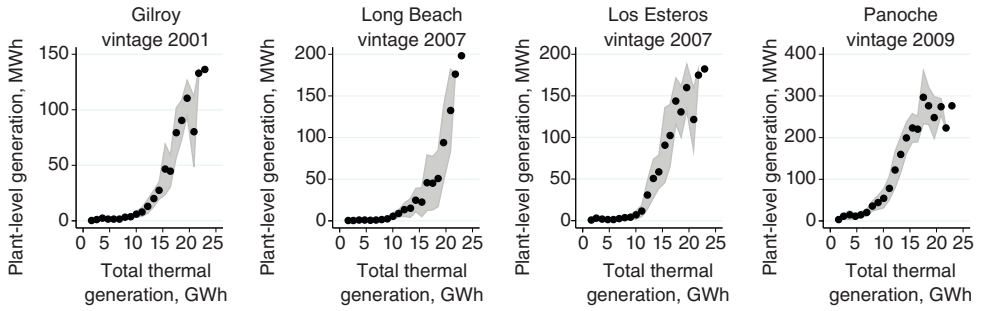
<sup>18</sup>In the online Appendix, we include results estimated with a post-period, which goes through June 30, 2013, and the estimated residual effects results are similar but somewhat attenuated. This is exactly what one would expect as investments in new transmission capacity begin to relieve the constraint.

<sup>19</sup>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.

Panel A. Combined cycle plants



Panel B. Combustion turbine plants



Panel C. Boiler plants

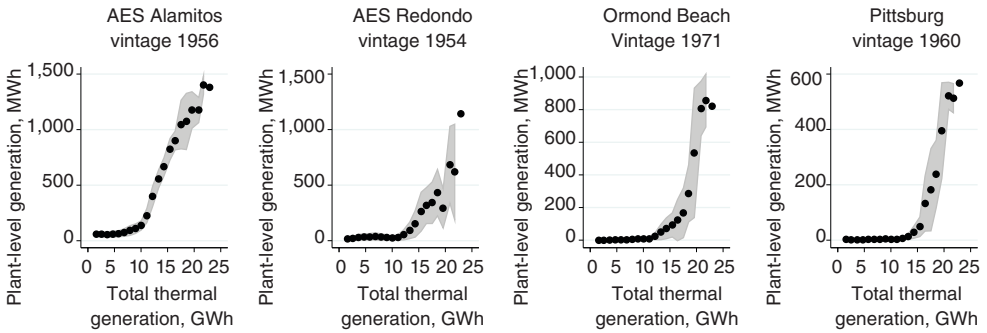


FIGURE 4. GENERATION REGRESSIONS BY INDIVIDUAL PLANT

Notes: 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. The 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 percent confidence intervals, where standard errors are clustered by sample month. The scaling of the y-axis differs across plants, reflecting differing plant capacities.

Thus, we are predicting how generating units will behave after the SONGS closure, modeled as a non-marginal shift in the net demand that each unit faces. Each unit's generation regression is identified using hour-to-hour variation, but the predicted effect of the SONGS closure is a shift in the entire distribution of net demand. The hourly variation is important, because as total demand varies tremendously across time, so does the impact of the closure on the behavior of individual generating units.

The residual effect we measure is the change in generation from the pre-period to the post-period, conditional on a given level of system demand:

$$(4) \quad \sum_b \sum_{j \in J} (\alpha_{bj}^{post} - \alpha_{bj}^{pre}) \cdot \theta_b^{post}.$$

Whereas the predicted effect models how a unit's behavior changes when the net demand that it faces increases, the residual effect measures how the unit's behavior changes conditional on a given level of net demand. Residual effects can be positive or negative, reflecting whether units are operating more or less than would be predicted from pre-period behavior. In the analysis that follows, we discuss potential drivers of these residual effects, as well as their impact on the cost of electricity generation.

Perhaps the most important drivers of residual effects are transmission constraints. Because SONGS was located in a load pocket, its closure led to binding physical constraints on the grid. To examine the broad pattern of transmission congestion, we begin by presenting results by region. Additionally, we evaluate the predicted and residual changes for subsets of hours when transmission constraints are most likely to bind. We consider two such subsets, each totaling approximately five percent of hours. First, we define weekday summer afternoons as 2 PM to 5 PM in months June through September. Second, we define high demand hours when total CEMS generation was in at least the thirteenth 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 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.

To attribute these residuals to the SONGS closure, the identifying assumption 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.<sup>20</sup> Moreover, while there was a significant decrease in hydroelectric generation in 2012, this would not have affected the ordering of the natural gas units and, if anything, would have made transmission constraints *less* likely to bind. 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

<sup>20</sup>Our methodology would be less useful in markets where fuel price changes affect the dispatch order between different forms of generation. For example, in many US markets natural gas combined cycle plants have been moving ahead of coal in the dispatch order (Cullen and Mansur 2014). Our methodology could still be used in these settings, but only for identifying predicted changes within each fuel type. Moreover, our methodology implicitly assumes that generators face very similar fuel prices. As we show in the online Appendix, this assumption is easily met in our context, but one could envision situations in which natural gas pipeline constraints and other bottlenecks would lead this to be violated.

small in magnitude. Moreover, it is hard to envision any alternative explanation for the particular pattern of regional and temporal residual effects that we observe.

#### IV. Main Results

##### *A. Impact on the Regional Pattern of Generation*

Table 3 describes the effect of the SONGS closure on the geographic pattern of generation in California during the twelve months following the closure. The reported estimates are average hourly changes in MWh. Panel A reports effects for all hours. The predicted change in generation is similar in the North and the South, with both regions predicted to increase generation by about 900 MWh per month. The Central California column represents many fewer plants, and accordingly a smaller predicted change (300 MWh). By design, the total predicted 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 percent of the lost output from SONGS would have been produced by plants located in Southern California.

The residual estimates show the displacement of generation from Northern generating units to Southern units. Relative to our predictions, the Southern units increased generation by 150 MWh, while the Northern units decreased generation 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 residual effect almost doubles, to a 237 MWh increase in the South and 260 MWh decrease in the North. In the five percent of hours with the highest level of system demand (panel C), the residual effect is an increase in the South of 431 MWh and a decrease in the North of 381 MWh. The estimates indicate that during peak periods as much as 75 percent of the lost generation from SONGS was met by plants in Southern California. This 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 3. The one notable exception is imports, which are responsive over some ranges of demand. To account for this, we calculated the predicted 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 percent of the lost generation from SONGS would have been replaced by imports. One could imagine adjusting the predicted estimates in panel A of Table 3 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 3. On weekday summer afternoons, only 4 percent of the lost generation would have been made up by imports, and in high demand hours it would have been less than 1 percent. Further details, discussion,

TABLE 3—THE EFFECT OF THE SONGS CLOSURE ON THE REGIONAL PATTERN OF GENERATION

	Average hourly change in net generation, by region		
	Southern California (SP26) (1)	Central California (ZP26) (2)	Northern California (NP15) (3)
<i>Panel A. All hours</i>			
Predicted change (MWh)	892 (18)	300 (15)	944 (18)
Residual change (MWh)	150 (73)	20 (66)	−140 (79)
<i>Panel B. Weekday summer afternoons</i>			
Predicted change (MWh)	1,068 (47)	259 (17)	822 (39)
Residual change (MWh)	237 (144)	76 (61)	−260 (119)
<i>Panel C. High demand hours</i>			
Predicted change (MWh)	1,207 (44)	174 (30)	753 (35)
Residual change (MWh)	431 (144)	4 (57)	−381 (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

*Notes:* This table reports our estimates of the change in generation that resulted from the SONGS closure on January 31, 2012. The predicted change is the increase in generation at marginal units, assuming 2,150 MWh of lost generation from SONGS. The residual change is 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 PM to 5 PM in months June through September. Panel C reports estimates for hours when total CEMS generation was in the thirteenth quantile (13,837 MWh) or greater. Standard errors (in parentheses) are clustered by sample month.

and figures plotting post-period generation regressions by category are presented in the online Appendix.

The table also reports standard errors. The predicted changes are estimated with a high degree of statistical precision and all nine estimates are strongly statistically significant. The estimated residual changes are much less precise and only marginally statistically significant in panel A. In the online Appendix, we report results from a series of placebo tests aimed at determining how unusual it is to observe this magnitude and pattern of residual effects. 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 residual 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 nonzero residual effects in

other years, they tend to be driven by long outages. To demonstrate this, we show several additional diagnostics on the estimated residuals. In the placebos with the largest estimated residual effects, the standard deviation, skewness, and kurtosis are all larger (in absolute terms) than in 2012, indicating extended outages and other large year-to-year changes in generation at a few individual plants rather than correlated changes in generation across many plants.

### B. Impact on Generation Costs

We next quantify the change in the total cost of production associated with these generation impacts. As is common in the literature, we calculate marginal cost for each generating unit using information on heat rates, fuel prices, and variable operations and maintenance costs (VOM):  $MC_j = \text{heat rate}_j \cdot \text{fuel price}_j + \text{VOM}_j$ . Details on these calculations are provided in the online Appendix.<sup>21</sup> 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 5, we plot the marginal cost curve for electricity in California for 2012. To construct this figure, we used data from several sources to calculate the marginal cost of every electric-generating unit in California. 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:

$$(5) (MC_j \cdot \text{generation}_{jt}) = \sum_b (\delta_{bj} \cdot 1\{\text{system-wide thermal generation}_t = b\}) + \mu_{jt}.$$

This regression again allows us to report separate estimates for predicted and residual changes. Results are given in Table 4. The predicted increase in the total hourly cost of thermal generation was \$29,000 in the South, \$8,000 in the Central region, and \$27,000 in the North—totaling \$63,000 statewide. The average cost implied is approximately \$29 per MWh. These estimates again assume that none of the lost generation from SONGS was replaced by imports. This is likely a good approximation because the California marginal cost curve is quite elastic in most hours, so the marginal cost of out-of-state generation necessarily must have been close to the

<sup>21</sup>This calculation abstracts from ramping rates and other dynamic considerations. This is common in the literature, but Reguant (2014) finds that start-up costs play an important role in bidding behavior and production patterns. Our preferred specification uses constant heat rates, thus averaging across differential fuel use during start-up and ramping, so as not to bias our results with changes over time in heat rates driven by confounding factors. To verify that our results are not sensitive to this specification, we considered several alternatives that allowed heat rates to vary over time. With these alternative specifications our results are qualitatively similar, and the estimate of the total cost impact of the SONGS closure is about five percent smaller.

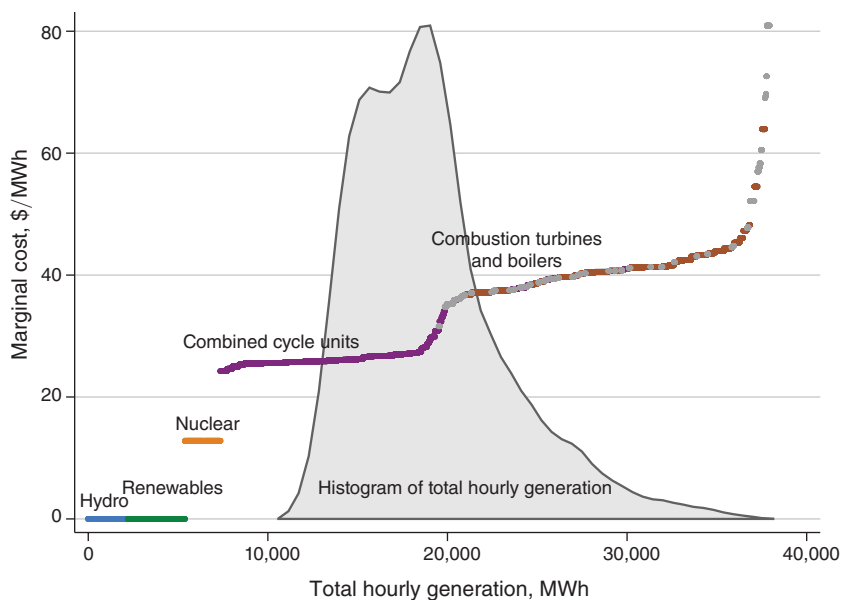


FIGURE 5. THE MARGINAL COST OF ELECTRICITY IN CALIFORNIA, 2012

*Notes:* 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. See the text for details.

marginal cost of the in-state generation. As such, we expect our estimate of \$63,000 to be close to the true change accounting for imports.

The residual changes are also significant, and their spatial pattern follows what would be expected from transmission constraints. While total hourly generation costs 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 average hourly increase of \$4,500 coming from the residual changes in generation. While lower-cost units were available in the North, they could not be used because of the transmission constraints. This residual 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. 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.<sup>22</sup> Maintaining some “reactive” power locally is another reason for higher-cost Southern units to operate more than predicted in 2012.

The total cost increase at thermal power plants statewide, averaged across all hours and including both predicted and residual effects, is almost \$68,000 per hour.

<sup>22</sup>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 for voltage regulation. In 2013, two generators at the Huntington Beach Plant were converted to synchronous condensers to provide local voltage support (CAISO 2013a). Since 2013, CAISO has also been taking steps to expand local transmission capacity in and around San Diego County (CAISO 2013d, 2014).

TABLE 4—THE EFFECT OF THE SONGS CLOSURE ON THERMAL GENERATION COSTS

	Average hourly change in total generation cost, by region		
	Southern California (SP26) (1)	Central California (ZP26) (2)	Northern California (NP15) (3)
<i>Panel A. All hours</i>			
Predicted change (\$000's)	28.6 (0.6)	7.9 (0.4)	26.5 (0.5)
Residual change (\$000's)	7.1 (2.9)	0.5 (1.7)	-3.0 (2.5)
<i>Panel B. Weekday summer afternoons</i>			
Predicted change (\$000's)	41.6 (1.6)	7.5 (0.5)	27.4 (1.4)
Residual change (\$000's)	8.8 (5.1)	1.4 (1.6)	-9.1 (4.2)
<i>Panel C. High demand hours</i>			
Predicted change (\$000's)	49.7 (1.9)	5.7 (0.8)	27.8 (1.4)
Residual change (\$000's)	16.3 (4.8)	-0.5 (1.7)	-14.5 (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

*Notes:* 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 3, but we have used our measures of marginal cost for each generating unit to calculate the change in total generation cost. 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.

This amounts to a 13 percent increase in total in-state generation costs.<sup>23</sup> 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.

Panels B and C of Table 4 report estimates of the generation cost impacts for weekday summer afternoons and high demand hours, when transmission constraints are more likely to bind. The predicted effects are larger than in Table 4, 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 residual changes in total cost are also higher than in panel A, reflecting a combination of larger residual changes in generation and higher

<sup>23</sup>To calculate this, we assume that the average hourly cost for other thermal generation (i.e., not observed in the CEMS data) is equal to the average cost we observe in our sample.



marginal costs. Imports do not substantially increase during peak periods, so we expect these estimates to be close to the true total change in cost. The system-wide total hourly change in thermal costs is \$78,000 on weekday summer afternoons, and \$84,000 in high demand hours. 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 (Table 4, panel C) also gives \$106,000 per hour. These measures are considerably higher than our estimate because supply is relatively inelastic during these hours so the marginal generating unit has a much higher cost than the inframarginal units.

### C. Impact 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 first calculate carbon emissions rates for all generating units in our sample. 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:

$$(6) \text{ (carbon\_rate}_j \cdot \text{generation}_{ji}) = \sum_b (\lambda_{bj} \cdot 1\{\text{net system-wide demand}_t = b\}) + \nu_{ji}.$$

Summing across all plants and all hours, we estimate an average increase of 1,030 tons per hour during the 12 months following the SONGS closure. For comparison, the average hourly total emissions at CEMS plants was 3,730 tons between 2009 and 2011, so this is more than a 25 percent increase in total emissions. As with the previous calculations, this assumes that 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 be approximately correct. If, however, there are *marginal* generators out-of-state that are fueled by coal, then our estimates will understate the total carbon impact. These calculations also assume that none of the emissions were offset via California's cap and trade program for carbon dioxide. While California power plants are currently covered by a carbon cap and trade program, they were not yet covered in 2012. As a result, the 2012 increase in carbon dioxide emissions caused by the SONGS closure would not have been offset.<sup>24</sup>

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

<sup>24</sup>Our annualized cost estimate does include January 2013 emissions, which totalled 0.7 million tons. These were covered by the new cap and trade program, but at a permit price of under \$15 (source: calcarbondash.org, based on ICE contracts), compared to the IWG's social cost of carbon of \$35 per ton that we use later in the analysis. Accordingly, only 3 percent of the twelve-month carbon costs that we report would have been internalized.

TABLE 5—THE TOTAL IMPACT OF THE SONGS CLOSURE

	Total impact during the twelve months following the closure (millions of dollars)
Predicted net increase in generation costs	311 (3.1)
Residual net increase in generation costs	40 (10.7)
Value of increased carbon dioxide emissions	316 (5.8)

*Notes:* This table reports our estimates of the total economic and environmental impact of the SONGS closure. The predicted net increase subtracts generation costs at SONGS from the predicted increase in thermal generation costs. The residual net increase is the additional increase in generation costs due to deviations from predicted plant behavior. These generation cost impacts include changes in fuel expenditures and other marginal costs, but not capital costs or fixed O&M. Carbon dioxide emissions are valued at \$35/ton. All dollar amounts in year 2013 dollars. Standard errors (in parentheses) are clustered by sample month.

marginal damages. Moreover, a portion of nitrogen oxide emissions are capped in the RECLAIM market around the Los Angeles area, so some of these increases may have been offset by decreases in other sectors.

#### D. Total Impact of SONGS Closure

Table 5 summarizes the total impact of the SONGS closure. We find that the SONGS closure increased thermal generation costs by almost \$68,000 per hour during the first 12 months following the closure. California nuclear plants have a marginal cost of about \$12.8 per MWh, so the SONGS closure also represents a savings of about \$28,000 per hour. Thus, the total net increase in generation costs is \$350 million during the first twelve months. This includes a predicted net increase of \$311 million and a residual net increase of \$40 million. Finally, using a social cost of carbon of \$35 per ton,<sup>25</sup> our estimates imply an increase in external costs of \$316 million during the first 12 months.

The table also reports standard errors. As with our previous results, the predicted effect is much more precisely estimated than the residual effect. With the predicted effect, identification comes from hour-to-hour comparisons between periods with different levels of net system demand. There is rich variation in net system demand driven by weather and other factors, so the coefficient estimates are precisely estimated. Identification of the residual effects relies in addition on comparing coefficient estimates before and after the SONGS closure, and consequently these are less precisely estimated. Moreover, with the placebo tests that we described in Section IVA, it is not unusual to observe large year-to-year residual effects. All six placebo estimates of the residual net increase in generation costs are smaller than \$40 million, but in some years the estimate is close in magnitude. Overall, the

<sup>25</sup>The central value of the social cost of carbon used by the US federal government for regulatory impact analysis is \$32 per ton (in 2007 dollars) (Interagency Working Group on Social Cost of Carbon (IWG) 2013), equivalent to \$35 per ton in 2013 dollars.

placebo results suggest that while the pattern of residual effects in 2012 is indeed atypical, the \$40 million estimate should be interpreted cautiously.

These estimates provide some of the components necessary for thinking about the private and social consequences of nuclear plant closures. In addition to generation cost impacts, the other relevant private cost is the fixed O&M required to keep a nuclear plant open. For SONGS, these costs were about \$340 million per year, approximately the same magnitude as the generation cost impacts. Discussions about nuclear plant closures also typically center around the external costs associated with operating a nuclear power plant including storage of spent fuel and accident risk. Quantifying these risks is very difficult because they involve small probabilities of large damages.

These results also highlight the evolving economics of US nuclear power. The generation cost impacts 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 generation cost impacts from the SONGS closure would have been more than twice as high. Along a similar vein, the convexity of the supply curve implies that the generation cost impacts also 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.

#### *E. Unusual Behavior at Individual Plants*

Our empirical approach generates estimates of predicted and residual effects not only at a regional level, but also for individual plants. In the online Appendix we show that these plant-level estimates are what one would expect based on the marginal cost curve. For example, across all hours, the largest predicted increases in generation are at large combined-cycle plants with low marginal cost. Also, the largest positive residuals tend to be at plants located in the South while the largest negative residuals tend to be at plants in the North.

During high-demand hours the plant-level estimates have a more distinct regional pattern. The largest predicted increases are at steam boilers and other plants with high marginal cost. The largest residual increases are at Southern plants. Also, as expected, several of the largest residual decreases are at plants in the North. There are two important exceptions, however. The two largest residual decreases in high demand hours were at plants in the South: Alamosa and Redondo, both owned by AES. These two large plants were on the margin in high demand hours, and they had large predicted changes. Moreover, given their location in the South, they would have been expected to have residual *increases*. To illustrate the anomaly these plants represent, we plot in Figure 6 estimated residual effects by plant for high demand hours, separated by region. The AES-owned plants are labeled. While the other Southern California plants generally exhibit positive residual effects, the estimated residual effects for two of the three AES plants are clearly large and negative.

As it turns out, the AES plants have been investigated for market violations. They were operated through a tolling agreement with JP Morgan Ventures Energy Corporation, a subsidiary of JP Morgan Chase. Following investigations by the

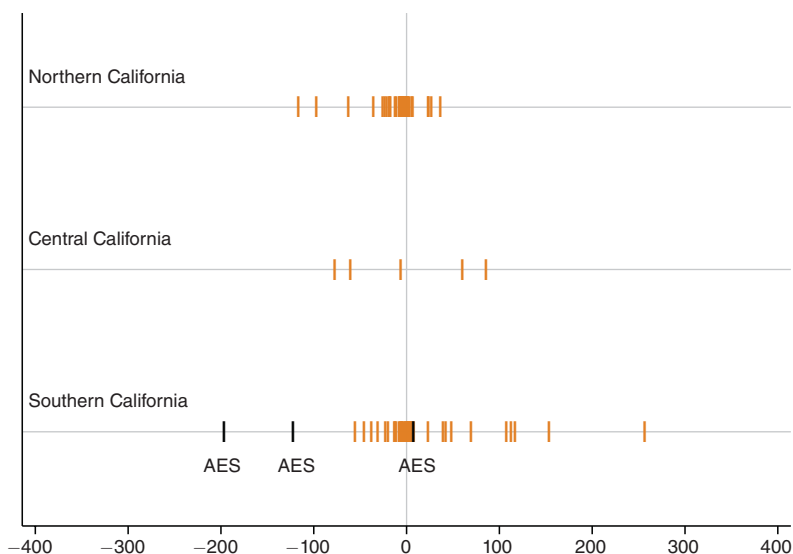


FIGURE 6. PLANT-LEVEL RESIDUAL CHANGES IN HIGH DEMAND HOURS

*Notes:* This figure plots plant-level hourly average residual changes by region. High demand hours are defined as hours when total CEMS generation was in the 13th quantile (13,837 MWh) or greater. AES-owned plants are labeled. Details on the calculations are given in the text.

California and Midcontinent System Operators (CAISO and MISO), the Federal Energy Regulatory Commission alleged market manipulation by JP Morgan at these and other plants.<sup>26</sup> 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. 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.<sup>27</sup> In 2013, JP Morgan agreed to pay a civil penalty of \$285 million and to disgorge \$125 million in alleged unjust profits.

<sup>26</sup>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.

<sup>27</sup>For details on the individual strategies, see FERC (2013). Since FERC alleged market manipulation in both the pre- and post-periods, we do not know whether the residual decreases at Alamos and Redondo are a result of unusually high generation in 2011 or withholding in 2012. Also, while much of the manipulation alleged by FERC was aimed at earning revenues through exceptional dispatch and other out-of-market operations, we do not observe these payments.

## V. Conclusion

Motivated by dramatic changes in the profitability of existing US nuclear power plants, we examine the exit decision of a large nuclear plant in California. We find that the SONGS closure increased the private cost of electricity generation in California by \$350 million during the first twelve months. For comparison, the annual fixed costs of keeping the plant open were around \$340 million, corroborating anecdotal reports about nuclear power plant profitability. Of the \$350 million, \$40 million reflects costs not predicted by the pre-period supply curve. This 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 noncompetitively.

The closure also 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 nuclear plants worldwide 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. Current policies aimed at reducing carbon emissions tend to focus on wind, solar, and other renewables, but keeping existing nuclear plants open longer could mean hundreds of millions of tons of carbon abatement.

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 noncompetitive 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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