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Technology Choices in the U.S. Electricity Industry before and after Market Restructuring

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We study the drivers of the adoption of electricity generation technologies between 1970 and 2014 in the lower 48 U.S. states. Since the 1990s, major electricity market restructuring took place in some parts of the United States. We explore the implications of changing from a regulated "cost-of-service" or rate of return system to a partly and fully deregulated market on technology and fuel choices. We find that electricity market deregulation resulted in significant immediate investment in various natural gas technologies, and a reduction in coal investments. However, market deregulation impacted less negatively on high efficiency coal technologies. In states that adopted wholesale electricity markets, high natural gas prices resulted in more investment in coal and renewable technologies.

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1. Introduction

We examine the drivers of investments in specific power plant technologies in the U.S. between 1970 and 2014, with a special emphasis on investment choices before and after electricity market restructuring. Technologies vary according to fuel type, whether they play a baseload, peaking, or intermittent role in the system, and energy efficiency. While the majority of studies claim that operational efficiency of power plants improved following deregulation, very little is known about the impact of deregulation on the fuel choice and technical efficiency of new electricity generation investments. While the long-term rate of return of a power generator investment does not depend on electricity prices, fuel prices, or technology choice under a cost-of-service regime, the rate of return depends on all these factors in a liberalized regime with wholesale markets. We use a state level panel data set to investigate the factors that affected new investments in the various electricity generation technologies. We find that own and substitute fuel prices, especially natural gas prices in states participating in wholesale electricity markets, and electricity market deregulation determine the fuel and technology choice of new investments.

Past research on the effect of market liberalization on the efficiency of the U.S. electricity industry has mostly focused on the effects on existing power plants (Wolfram, 2005; Borenstein and Bushnell, 2015; Fabrizio et al. 2007). Borenstein and Bushnell (2015) note an overall positive influence of restructuring on power plant operations. Davis and Wolfram (2012) found that deregulation was associated with about a 10% increase in operating performance at nuclear power plants, due to higher capacity utilization. Craig and Savage (2013) find that full electricity market liberalization (access to both wholesale and retail markets) has increased the technical efficiency of investor owned plants by about 9%, due to improvements in technologies and organizational practices. They find further evidence that such efficiencies may have spilled over to the public sector.

Recent research (e.g. Fleten et al., 2017; Fleten and Näsäkkälä, 2010) on the decision to invest in individual power plants investigate for example the partially irreversibly decisions to start up, abandon or shut down electricity production assets in the US. Using a sample of 1121 generators for the period 2001-2009, Fleten et al. (2017) find that regulatory and profitability uncertainty reduces the probability of shut down, while regulatory uncertainty reduces the probability of startup as well. While the investment decision process of irreversible investments under uncertainty is well documented in finance and microeconomics (Caballero and Pindyck, 1996; Bloom et al., 2007), we are not aware of research that focuses on the effect of liberalization on the fuel and technology choice of new power generation investments, which is the focus of this paper.

The paper is structured as follows: the next section introduces relevant background information on the policy regime and the factors affecting investment decisions in the power generation sector. The third section presents the model and the data and the fourth section our results. The final section provides conclusions and discusses the possible policy implications of our results.

2. Background and Theory

a. U.S. Energy Policies

Following the 1973-74 oil crisis, the choice of power technologies for new investments saw a marked change. There was a shift away from oil-fired generators towards primarily coal, small-scale hydro, and to an extent nuclear energy, even though after the Three Mile Island accident in 1979 there were no new nuclear investments for several decades. Energy security considerations led policymakers to support the shift to new energy sources on the legislative level. The Public Utility Regulatory Policies Act of 1978 (PURPA) created legal categories for "qualifying facilities", and independent power producers (IPPs). The National Energy Policy Act of 1992 subsequently allowed utilities to "enter the IPP business as exempt wholesale generators, or EWAGS. This allowed IOUs (investor owned utilities) through subsidiaries to develop power plants to sell power to other utilities" (Warwick, 2002, p 3.10). These regulations set the legal background enabling electricity market liberalization.

Figure 1 depicts selected key technology capacity additions in the U.S. The graph shows several distinct periods of investment in different fuel choices and technologies. While nuclear power and pulverized coal dominated additions to the grid from the 1970s to the mid 1980s, the period after 2000 was characterized by investment in natural gas base- and peak-load capacity. From 2005 onwards we can also observe increased additions of onshore wind turbines and solar photovoltaic generation.

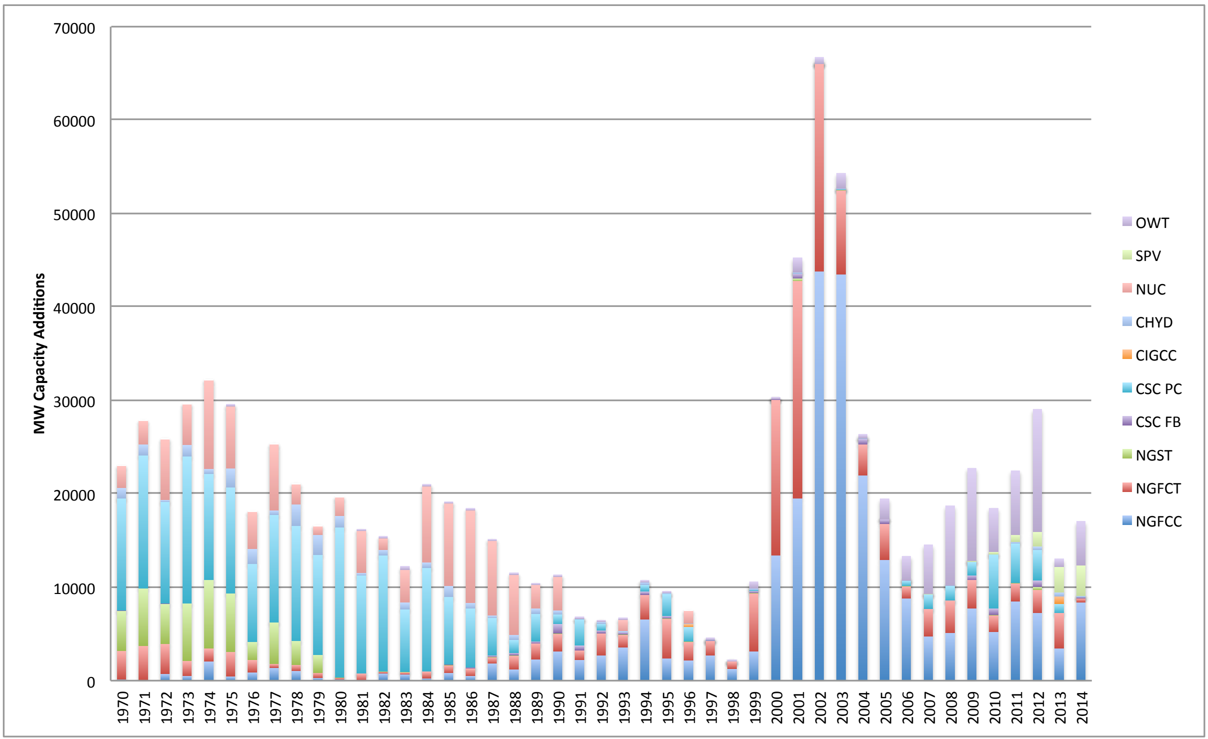

Figure 1: Key technology additions to U.S. electricity generation capacity, measured in MW nameplate capacity 1970-2014, including natural gas fired combined cycles (NGFCC), natural gas fired combustion turbines (NGFCT), natural gas steam turbines (NGST), conventional steam coal-fluidized bed technology (CSC-FB), conventional steam coal –pulverized coal technology (CSC-PC), coal integrated gasification combined cycles (CIGCC), conventional hydroelectric (CHYD), nuclear (NUC), solar photovoltaic (SPV), and onshore wind generation (OWT). Source: Form 860 - Y2014 (EIA, 2016a).

Natural gas regulation has also had a strong direct effect on electricity markets. The development of natural gas prices has been a crucial factor in driving technology adoption, as natural gas tends to be the fuel determining the marginal cost of electricity supply in the majority of deregulated electricity systems (Borenstein and Bushnell, 2015). Effective natural gas price controls in the U.S. go back as far as the 1950s (Joskow, 2003). These regulations however resulted in an acute undersupply of natural gas by the mid-1970s (Joskow, 2003). The Natural Gas Policy Act of 1978, which was passed partly as a response to shortages in natural gas, deregulated the supply of new gas, by essentially eliminating price caps (Warwick, 2002). This resulted in increased gas production and falling prices starting in the mid 1980s. As a final step, restrictions on wellhead prices of natural gas were entirely removed by the Natural Gas Wellhead Decontrol Act of 1989 (Joskow, 2003).

Figure 2 shows the development of average real coal and natural gas prices over the past 45 years. The real level of prices has not drastically increased since the 1970s, even though natural gas prices fluctuated heavily.

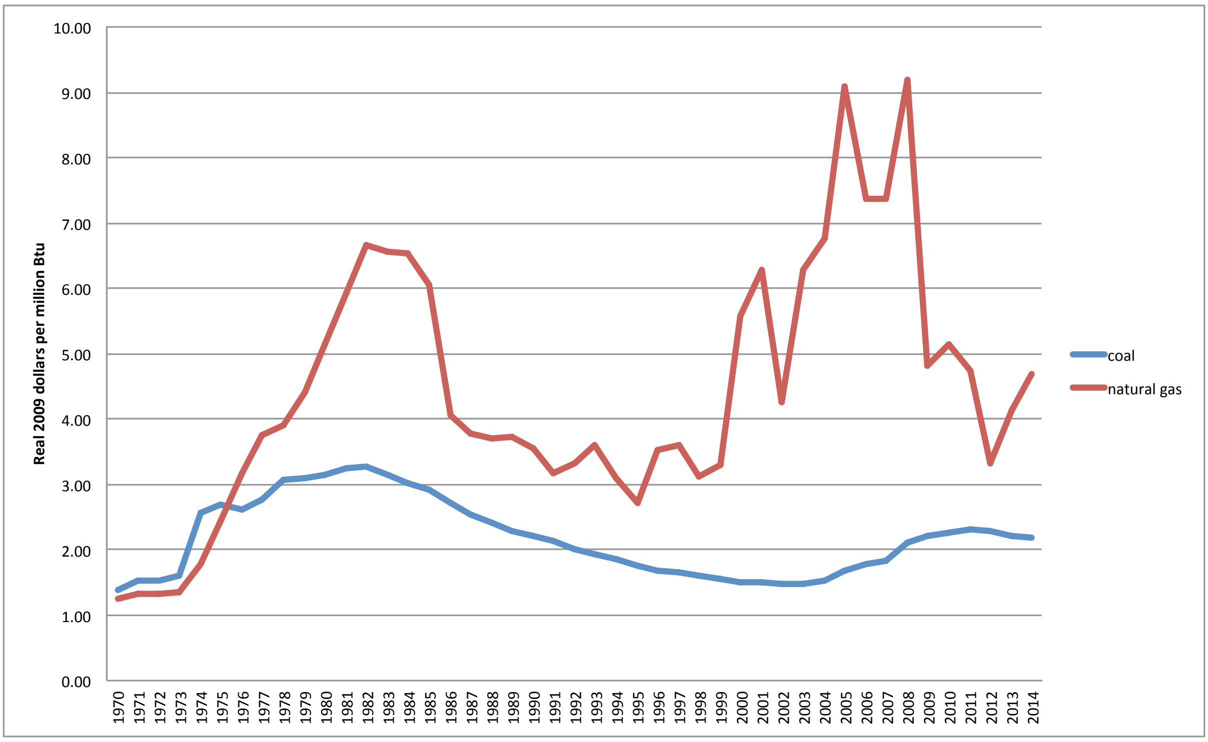

Figure 2. Real coal and real natural gas prices in the electric power sector (US average). Source: EIA State Energy Data System (EIA, 2014), expressed in real dollars per million Btu.

By the end of the 1980s, the major obstacles facing gas exploration and production were regulated pipeline transportation rates and the pipeline companies' control of end user prices (Warwick, 2002). FERC Orders 436 and 500 aimed at introducing competition into the pipeline industry, while maintaining federal regulation of the transportation function. FERC Order 636 in 1992 then finally restructured the gas industry by requiring pipeline companies to "open their capacities to any and all transporters and unbundle their transportation service so as to allow customers to select supply and transportation" at will (Warwick, 2002, pA.16). As a result gas exploration soared, and by 1996-1997 prices fell considerably. The electricity market reform was initiated under these circumstances.

b. Electricity Market Regulation

The economic and political incentives for electricity market restructuring thus originate in a period of historically low gas prices as well as high reserve generating capacity resulting in much higher average than marginal cost of electricity generation in most parts of the United States (Borenstein and Bushnell, 2015). Before market restructuring efforts began in the late 1990s, the U.S. electricity industry was characterized by a cost-of-service model, in which the regulator set electricity prices in a manner that allowed IOUs to recover their "prudently-incurred operating costs and a regulated return on capital investment" (Borenstein and Bushnell, 2015, p438). By contrast, price setting in liberalized wholesale electricity markets[1] is generally based on equilibrium between supply and demand, where the price is at or above the marginal production cost of the last supplier needed to satisfy demand (Borenstein, 2000). If the average cost of electricity generation (based on the entire portfolio of base- and peak-load generators running on different fuels with different capital costs) is significantly higher than the marginal cost (defined as the marginal cost of the generating unit which is last on the grid), strong economic incentives would exist in favor of market liberalization at the generation level. Therefore, as Borenstein and Bushnell (2015) claim, political sentiments towards market liberalization are best described by "comparing average to marginal costs."

Electricity market deregulation may occur with regard to four different stages in the supply of electricity to consumers: "the generation of electricity, long distance transmission, voltage step down, and local distribution to end users and retailing" (Borenstein and Bushnell, 2015, p439). Following Craig and Savage (2013), we can distinguish between partial and full competition in electricity markets, defining the first as access of new entrants to wholesale markets, and the latter as access to both wholesale and retail markets. The liberalization process in the United States focused foremost on electricity generation, culminating in the divestiture of a large number of IOUs and in the market entry of new generation capacity provided by independent power producers (IPPs). Borenstein and Bushnell note that the share of electricity generated by IPP generators increased from 1.6% to 35% from 1997 to 2012. The transition to wholesale competition was most likely to occur in regions where the average cost of generation was above marginal cost, such as the North-East, Illinois, Texas, California, and Montana (Borenstein and Bushnell, 2015). Regions with comparatively low electricity rates at the end of 1990s, such as the South-East or the North-West largely resisted restructuring efforts.

In wholesale electricity markets, natural gas prices thus began to largely determine electricity prices, as fuel costs comprise approximately 80% of the variable costs of natural gas fired

[1] Energy only and capacity market pricing differs in this respect.

power plants (Craig and Savage, 2013). Following both natural gas and electricity market liberalization, the number of new natural gas generators (mostly natural gas combined cycle plants, and natural gas combustion turbines) skyrocketed, compared to other generation sources. However as natural gas prices drastically increased by the second half of the 2000s, the building of new natural gas fired power plants dropped considerably. During this time-period, the marginal profit of firms using non-natural gas powered generation was far higher than before liberalization.

This phenomenon, coupled with the California electricity crisis of 2000-2001 (Joskow, 2001; Bushnell, 2004) has in many cases reversed the relationship of marginal and average costs (Joskow, 2008), and led to the suspension of any further restructuring activities in U.S. markets (Craig and Savage, 2013).

c. Factors Driving Power Plant Investment Decisions

Investment in power generation infrastructure and capacity is a long-term commitment that may take several decades to break even. The expected return on such investment will be determined by the discount rate, and future operating costs and revenues, all of which are uncertain. While capital costs are predictable to a good extent - even though large projects tend to be over-due and over-budget (Flyvbjerg, 2014) - future operating expenses of a power plant are mostly determined by the cost of its main fuel and the efficiency with which it uses this fuel, while total average cost depends crucially on capacity utilization and initial capital costs.[2] Future revenues, and therefore, the profit maximization strategy to be used, are determined by the regulatory-regime in place (including capacity markets in some parts of the US) and demand. In deregulated markets competition from other suppliers is also relevant.

[2] The ultimate investment decision in a generation unit will be determined by the expected return on investment, and the estimated difference between the levelized cost of the energy generating technology (LCOE) and the levelized avoided cost of electricity (LACE). LCOE is defined as: "the present discounted value of costs associated with an energy technology divided by the present discounted value of production—that is, it is a measure of the long run average cost of the energy source" (Covert et al., 2016, p12). LACE measures "what it would cost the grid to generate the electricity that is otherwise displaced by a new generation project" (EIA, 2016b, p2). Comparing a technology's LACE and LCOE tells us whether the project's value exceeds its costs. Hence, a direct comparison of levelized costs becomes difficult due to the uncertain nature of future fossil fuel costs, and due to the regionally differing capacity utilization of intermittent renewables (EIA, 2016b).

Under cost-of-service regulation, changes in costs due to changes in fuel prices or technology will be reflected by the end-user price and easily passed onto the customer. There is little economic incentive in such a regime to invest in high efficiency but higher cost technologies, given a guaranteed return on capital investment and the coverage of operating costs, even though potentially higher end-user energy prices might lead to technological innovations and to efficiency improvements in end-use equipment (Ley at al., 2016; Popp, 2002; Newell et al., 1999).

A good example of decreasing energy efficiency under regulated markets is the switch from mainly supercritical to subcritical coal power during the 1970s and 1980s. Yeh and Rubin (2007) note that the thermal efficiency of new U.S. coal plants declined in the 1980s, due to the "demise" of supercritical plants, that were popular in the late 1960s and 1970s, with almost two thirds of the new generators built between 1970 and 1974 being supercritical (Figure 3). The reasons for abandoning higher efficiency plants were found in lowered demand for new plants in the 1970s, and technological problems leading to large operating and maintenance costs (Yeh and Rubin, 2007). Lowered demand for new electricity investments usually favored smaller, subcritical investments. Recent developments have, however, seen a moderate increase in supercritical plant construction in the U.S. In general however, the majority of the U.S. coal fleet was built in the 1970s and 1980s, and thus is decreasing in efficiency due to age (Campbell, 2013).

Under deregulated wholesale markets, however, the relative profitability of one type of power plant over the other can decide between survival and bankruptcy. Plants with lower marginal costs receive a higher place on the dispatch ranking, and, therefore, make relatively higher operating profits due to both their greater price-marginal cost margin and a higher frequency of supply (Craig and Savage, 2013). Of course, plant owners still have to recover initial capital expenditures and ongoing interest payments. Often, low marginal cost technologies can have higher capital costs. Natural gas-fired combined cycle power plants – usually used for baseload supply-, for example, might have higher capital expenses, but lower marginal costs than natural gas fired combustion turbines, which are used for peak supply. As currently both base and peak load supplying generation are necessary for a functioning electricity system, technologies and fuels compete with each other across these categories in a liberalized system. Energy storage developments however may in the future significantly alter this landscape.

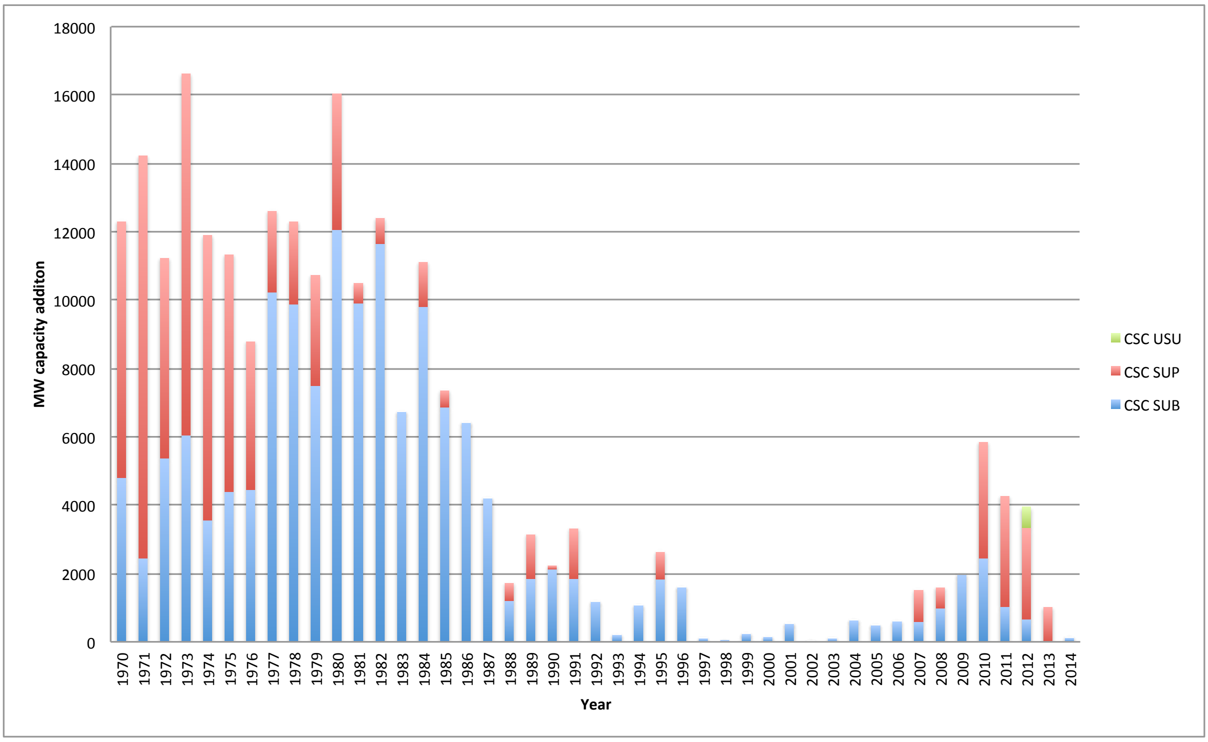

Figure 3: Subcritical, supercritical and ultrasupercritical steam coal generator investments, 1970-2014. Source: Form 860 - Y2014 (EIA, 2016a).

Therefore, while in regulated markets there is little to no economic incentive to invest in high-efficiency technology, competitive liberalized markets should in theory encourage such investments. Highly efficient generating units have thus the potential to significantly reduce fuel input costs, and hence operating expenses and their marginal bidding price. In practice, however, market imperfections arising from the regulatory and financial uncertainties surrounding deregulated markets, including potential market-redesign, limits and caps on wholesale prices by the regulator, and operators' reliability actions that depress market prices discourage private investments in the power sector (Joskow, 2008). In particular U.S. markets were designed with quite low wholesale price caps in order to limit the exercise of market power, but "these efforts to mitigate market power in the short run may create adverse generation investment incentives in the long run" (Joskow, 2008, 23). This investment disincentive especially affects investments in peak-load capacity that rely on high wholesale market prices to support investment costs based on limited capacity utilization. Thus, energy-only markets, as typically constructed, result in insufficient investments in generating facilities (Joskow, 2008; Knittel, 2015).

As we see, the development of fuel prices is crucial in liberalized markets for three reasons. Firstly they are the main factor determining the operating cost of the plant, secondly natural gas prices tend to drive the wholesale electricity price, therefore, the price-cost margin is determined by the difference between different fuel costs, and thirdly, they heavily influence capacity utilization of existing power plants.

Capacity utilization is a key factor determining the viability of a plant, and is influenced also by spare capacity available, and by the development of electricity demand. The EIA (2016c) reports that during the period of high natural gas prices in 2005-2008 utilities would only run natural gas fired combined cycle plants, after the maximum coal capacity had been exploited. While start-up investment costs might be correlated with future capacity utilization of a plant as some plants are designed for base-load, others for peak-load, actual utilization will depend firstly on the development in electricity demand and available spare capacity, and secondly on the market prices of fuels in an open market, in particular natural gas. For example, at the time of writing, following lower market prices for natural gas, the utilization of natural gas plants has again increased. The EIA (2016c) reports capacity factors for the U.S. natural gas combined cycle fleet to have risen from 35% in 2005 to about 56% in 2016. At the same time the average coal fleet utilization declined in the long run from around 70% in 2005 to about 55% in 2016 (EIA, 2016c). Renewable resources run at lower capacity utilization on average, with 33% reported for wind, 29% for solar photovoltaic, and 23% for solar thermal generators (EIA, 2016d).

When investors form their expectations about future prices[3] in the planning process, the only available information is the current price, and the price development of the past few years. As we have seen following the oil crises, or the shale gas boom, expectations about natural resource prices can go easily wrong. Despite this, these expectations formed by market participants play a crucial role in the choice of the investment. The decision whether to invest at all on the other hand is influenced by the expectations about changes in future demand in the long run, coupled with expected changes in total available peak or baseload capacity, considering retirements.

[3] While real fuel prices are in fact stationary over 40-50 years, there are decadal periods of consistently increasing and decreasing prices, that we assume influence decision-making.

3. Models and Data

a. Models

The question we are trying to answer is: What drives the building of certain types of power plants, defined as a combination of fuel and technology? In particular, how do own and substitute fuel prices under regulated and liberalized markets impact on the choice of fuel and the efficiency level of the new plant? And, most importantly, is there a discernable impact of electricity market reform on the construction of different types of generating units?

We will test the hypotheses introduced in the previous section about fuel prices and market liberalization on technology and fuel choices of new investments, by controlling for the levels of own and substitute fuel prices in the period prior to construction. In liberalized markets, higher fuel prices are expected to shift the balance towards more efficient generation technologies.

A key driver of investments (and capacity utilization) besides prices and market structure is long-term electricity demand development. Parts of the U.S. market had large reserve margins in the early 1990s indicating underutilized capacity (Borenstein and Bushnell, 2015). Yet market liberalization saw unprecedented investment in natural gas fired electricity generation (EIA, 2016a), triggered by both natural gas and electricity market liberalization in the hope of higher returns on investment. While only very moderate increases (around 1% p.a) in electricity demand are expected in the future (EIA, 2016e), a large number of power generating technologies originating from the 1960s and 1970s will have to be retired in the coming decades.

Our basic model for each technology type is:

$$
\begin{aligned}
A^{k}{}_{i,t} = {} & \alpha^{k} + \left({\beta_1}^{k} + {\beta_3}^{k} PLIB_{i,t}\right)\frac{1}{3}\sum_{j=L}^{L+3} Pcoal_{i,t-j} + \left({\beta_2}^{k} + {\beta_4}^{k} PLIB_{i,t}\right)\frac{1}{3}\sum_{j=L}^{L+3} Pgas_{i,t-j} \\
& + \gamma^{k} PLIB_{i,t} + \zeta^{k} FLIB_{i,t} + \lambda^{k}\frac{1}{3}\sum_{k=1}^{K}\sum_{j=L}^{L+3} A^{k}{}_{i,t-j} + \rho^{k}\frac{1}{3}\sum_{k=1}^{K}\sum_{j=L}^{L+3} R^{k}{}_{i,t-j} \\
& + \varrho^{k}\sum_{j=L}^{L+3}\tilde{Y}_{i,t-j} + \mu_i^{k} + \tau_t^{k} + \varepsilon_{i,t}^{k}, (1)
\end{aligned}
$$

given $\sum_{k=1}^{K} a^k{}_{i,t} \neq 0$ and where, $A^k{}_{i,t} = \log(a^k{}_{i,t})$ is the natural log of the capacity addition of a given technology "*k*" in state "*i*", in year "*t*", and *K* is the number of different technologies that might be invested in. We added 1 MW capacity to each datapoint in order to avoid zero values before taking the natural log. State-year observations without any capacity additions were eliminated from the dataset, as zeros would not mean a choice between technologies but the decision not to build at all.[4] $Pcoal$ is the log of the real price of coal delivered to the electricity sector and $Pgas$ is the similar price of natural gas. These prices are averaged over a three year period prior to the estimated time that construction decision commences. We found this averaging to be necessary, as investment decisions are not made based on annual prices but on a range of prices in the current and previous years. Combining the planning, authorization, and building phases, we assume coal and gas fired generators can take on average 4 years to be built,[5] so that $L = 4$ for coal and gas technologies. For nuclear technologies we set $L = 9$ and for renewable technologies $L = 2$.[6] These lags also mean that there cannot be reverse causality from the amount of new technologies built to fuel prices. As a robustness check we also use EIA (2017) estimates of lead times for new technologies entering service in the future. These are as follows: 4 years for most coal technologies, 3 years for gas combined cycles, 2 years for combustion turbines, 6 years for advanced nuclear plants. The EIA's definition of lead time is: "the time between the commencement of the licensing process, to the date of commercial operation" (EIA, 2004 p57). We add 1 year to this, to account for the planning and decision making phase. We report these results in Tables 1b and 2b.

Based on Craig and Savage's (2013) definitions, PLIB is a dummy for at least partly liberalized markets, and FLIB the dummy for fully liberalized markets. Retail choice is given in this definition, when at least 10% of the customers have the choice between 2 or more retailers.[7] In total 37 states fall into the category of at least partly liberalized, (meaning at

[4] Results for the full panel without this restriction do not significantly deviate from the results of Table 1a and 1b, however the coefficient estimates are generally lower.
[5] The OECD/NEA (https://www.oecd-nea.org/news/press-kits/economics-FAQ.html) and the EIA(2017) estimates 4 years construction time for coal and 3 for natural gas power plants. We have chosen 4 years uniformly. Robustness checks with EIA (2017) data are carried out.
[6] The median construction time without the planning and authorization phase of all reactors in the U.S. is 7 years (Csereklyei et al. 2016).
7 Retail choice definitions in a state may vary from that of Craig and Savage (2013). See for example Morey and Kirsch (2016), who also note retail choice introduction and suspension for Arkansas, Arizona, Montana and Oregon.

least access to wholesale markets), while 17 of these are fully liberalized at some point during the observation period. As fully liberalized states are also marked as partly liberalized, as Craig and Savage (2013) note that the full liberalization dummy measures the incremental impact on technology adoption, "beyond access to wholesale electricity markets." Thus, we measure the effect of wholesale market and retail market choice on electricity investments both across states and before and after liberalization within states. A number of states suspended either wholesale and retail liberalization efforts. For these states (Arizona, California, Virginia) we set the dummy back to "0" after the suspension of market restructuring activities.

We also interact the natural log of fuel prices with the partly liberalized dummy to measure the difference in impact of fuel prices on technology choice in liberalized and non-liberalized regimes. The relative marginal profit of a generator in a wholesale liberalized market will be determined by the difference between the electricity market clearing price (that might be at or higher than the marginal cost of the last generating unit) and the marginal cost of generation (which will be mainly driven by fuel costs in the case of fossil fuel generation). As wholesale prices are not available for each state and year, and a state might belong to different electricity trading hubs, we assume that natural gas prices are the key drivers of wholesale electricity prices. We are interested in the impact of fuel prices in wholesale markets as wholesale market prices determine the profitability of a power plant.

Lastly, power plants are built when there is sufficient expected return on the investment. This is only possible when sufficient additional demand is present to drive construction and ensure capacity utilization, sufficient number of plants are retired and thus freeing up needed capacity, or market incentives are present for the new capacity even without additional demand. But, as we noted, parts of the U.S. market had already in the 1990s overcapacity and thus underutilization. To measure the long-term development in power generation capacity and the lock-in nature of construction (and through it changes in supply), we control for the lagged 3-year average capacity additions across all technologies before construction started ($\frac{1}{3}\sum_{k=1}^{K}\sum_{j=L}^{L+3} A^{k}{}_{i,t-j}$), for the lagged 3 year average state GDP growth rate ($\sum_{j=L}^{L+3} \tilde{Y}_{i,t-j}$) and for lagged 3 year average retirements ($\frac{1}{3}\sum_{k=1}^{K}\sum_{j=L}^{L+3} R^{k}{}_{i,t-j}$).

As a robustness check, we also reformulate the dependent variable as ratio of the annual additions of each technology to the total existing cumulative capacity at the start of the period:

$$\hat{A}^k{}_{i,t} = \alpha^k + \left(\beta_1{}^k + \beta_3{}^k PLIB_{i,t}\right)\frac{1}{3}\sum_{j=L}^{L+3} Pcoal_{i,t-j} + \left(\beta_2{}^k + \beta_4{}^k PLIB_{i,t}\right)\frac{1}{3}\sum_{j=L}^{L+3} Pgas_{i,t-j}$$

$$+\gamma^k PLIB_{i,t} + \zeta^k FLIB_{i,t} + \lambda^k \frac{1}{3}\sum_{k=1}^{K}\sum_{j=L}^{L+3}\widehat{A^k}_{i,t-j} + \rho^k \frac{1}{3}\sum_{k=1}^{K}\sum_{j=L}^{L+3}\widehat{R^k}_{i,t-j} + \mu_i^k$$

$$+ \tau_t^k + \varepsilon_{i,t}^k, (2)$$

where $\widehat{A^k}_{i,t} = a^k{}_{i,t}/C_{i,t-1}$and C_{it} is total installed generation capacity in state *i* in year *t*. $\widehat{R^k}_{i,t} = r^k{}_{i,t}/C_{i,t-1}$, where r denotes retirements. As before, we drop observations where $\sum_1^K a^k{}_{i,t} = 0$.

Defining our dependent variable as the fraction of the new specific technology investment to the cumulative total helps to control for state size as well as for the relative magnitude of the technology investment. Similarly, $\frac{1}{3}\sum_{k=1}^{K}\sum_{j=L}^{L+3}\widehat{A^k}_{i,t-j}$ denotes the ratio of the average capacity additions of the 3 years prior to construction across all states and technologies to the average cumulative technology installed across all states and technologies of the 3 years prior to construction. We use state fixed effects, μ_i to control for unobserved state specific characteristics including environmental laws, policy environment, availability of financial credit, and consumer laws of the state, τ_t is again a national time trend.

b. Data

We constructed a state-level panel dataset for the period 1970 to 2014. Additions to specific generating technologies were sourced from EIA 860 form for 2014. The EIA 860 (3.1 Generator) form includes currently operating and retired generating units in the United States by state, fuel, technology, and subtechnology, giving the date of first operation and retirement (EIA, 2016a). By using the 26 distinct technology categories defined by the EIA, and assigning capacity (measured in MW nameplate capacity) to the year of its first operation, we are able to construct a capacity additions database for all states between 1891 and 2014. The EIA data encompasses utility and IPP investments into electricity generation, but not residential and industry-own generation, therefore certain energy technologies, such as solar photovoltaic might be underrepresented. Due to the availability of price and income data however, we only use data from 1970 to 2014.

We also defined 6 sub-technologies within the conventional steam coal (CSC) category. These refer to the steam cycle (subcritical, supercritical, and ultra-super critical) and to specific (efficient and less efficient) technologies such as stoker technology (oldest), pulverized coal (one of the most widespread coal technologies today), and fluidized bed (both highly efficient and environmentally friendly) technologies. As the EIA 860 dataset's categorization of subtechnologies is not mutually exclusive (sums up to more than the total capacity additions in the CSC category), we decided not to further break down the sample by multiplying steam cycle categories with these categories. Also, this would have further reduced our observation numbers for each category.

In this paper, we only estimate regressions for natural gas fired combined cycle plants (ngfcc), natural gas fired combustion turbines (ngfct), conventional steam coal fluidized bed generator (csc_fb), conventional steam coal pulverized coal technology (csc_pv), coal sub – and supercritical plants (csc_sub, csc_sup), nuclear reactors (nuc), solar photovoltaic (spv) and onshore wind turbine (owt). Several highly efficient technologies did not have enough observations to estimate a regression. For example, there are only two observations on coal integrated gasification combined cycle technologies.

Price data, including the nominal values for coal and natural gas price in the electric power sector were sourced from the EIA's (2014) State Energy Data System (SEDS). We used the 2009 St. Louis Fed deflator to convert the values to 2009 dollars. The EIA (2014) reports that some of the prices for given states/years have been estimated, based on a number of assumptions, such as the prices in neighboring states, regional and national prices, or the growth rate of the prices in adjacent regions. A detailed description of the methodology is found in the EIA (2014) technical notes.

As the SEDS dataset was still missing some prices, we have taken the same approach as the EIA (2014) and have estimated missing state-years using the average of the neighboring states' prices where original SEDS data was available. Averaged values were not used to generate further averages, except for Maine. As the only direct neighbor of Maine is New Hampshire – we had to use the data originally generated for New Hampshire. Due to the lack of substantial electricity generation in Washington D.C., and the lack of prices for Hawaii and Alaska (where estimation based on land borders was not possible), we have excluded these 2 states and Washington D.C. from the dataset.

The state GDP series was constructed using data from the Bureau of Economic Analysis (BEA), and the St. Louis FED deflator. From 1997 to 2014 we used the BEA NAICS real GDP series in chained 2009 dollars.[8] The BEA warns of a discontinuity in the GDP-by-state time series at 1997, where the Bureau shifted from SIC industry definitions to NAICS industry definitions. While the NAICS definition is consistent with the U.S. gross domestic product, the SIC definition measures the U.S. gross domestic income. Therefore, we used the growth rate of the SIC GDP series after it was converted to real (2009) dollars, and extrapolated the NAICS series backward with these growth rates.

4. Results

We present the estimates of Equation (1) in Table1a. The impact of partly liberalized markets is positive for natural gas combined cycle plants at the 10% significance level, and negative for most types of coal technologies at the 1% level.. The coefficient is negative for both super and subcritical coal fired generators, however somewhat lower for supercritical coal plants. We do not find any impact of wholesale liberalization on fluidized bed generators. As most coal generators built after 2000 were supercritical, our results show that high efficiency coal generators (including fluidized bed plants) are less negatively influenced by market liberalization. Market liberalization also resulted in increased investment into high efficiency combined cycles. In summary the negative effect is greatest for the least efficient coal technology and most positive for the most efficient natural gas technology. The incremental impact of fully liberalized markets is generally not statistically significant. These results reflect that after controlling for a nation wide time trend, wholesale market liberalization increased investments in natural gas generation, and decreased investments in coal technologies. There is also some evidence that market liberalization benefited investments into more efficient technologies.

The own fuel price elasticity of coal is negative but not statistically significant for pulverized coal technologies in non-liberalized markets. The magnitude of the coefficient varies between 0.3 and 0.8 meaning that a 1% increase in the average coal prices in the years before

[8] According to the BEA definition, GDP by state is derived as the sum of the GDP originating in all the industries in a state (BEA, 2016).

construction started would result in about 0.3% to 0.8% less new capacity addition in these technologies, in years where some capacity was added. In liberalized markets the effect is positive but only significant for subcritical plants at the 10% level.

In non-liberalized markets, the own price elasticity of natural gas plants is negative and significant at the 5% level for combined cycle generators, which are predominantly used to supply baseload demand, while the coefficient is negative but not significant for gas turbines, used to supply peak load demand. The effects of fuel own fuel elasticities change under wholesale market liberalization. In liberalized markets the elasticities are highly significant and more negative for both gas technologies. The coefficient for combined cycles is -1.67 and for gas turbines is -1.92, indicating a very elastic response in investment to gas price changes. Both coefficients are significant at the 1% level. These results are sensible, as, peak loaders, whatever their fuel, are used very flexibly and have to recover their investments in periods of high demand and therefore, very high electricity prices. In regulated markets with a guaranteed return on investment, this is not the case however. This is in line with the finding of Joskow (2008), who notes insufficient investment into peak-load technologies under liberalization.

The cross price elasticities of natural gas and coal technologies are not statistically significant in non-liberalized markets. The cross price elasticities of coal technologies with respect to the price of natural gas in liberalized markets however show a clear investment substitution towards coal fired baseload generation in case of rising natural gas prices. The combined coefficients vary between 0.91 for supercritical and 1.02 for subcritical technologies and are significant at the 5% level. This would indicate about 1% increase in new coal capacity investment as a response to 1% increase in natural gas prices. The three- to four-fold increase of natural gas prices in the early-mid 2000s, resulted in relatively higher marginal income for non-natural gas fired baseload generators. As a result of the gas price hikes, operators were running natural gas fired power plants only when all available coal, nuclear or renewable capacity has been exploited, therefore further decreasing the capacity utilization and the profitability of natural gas baseload generation.

While new coal additions during the 2000s were negligible, the years 2010-2013 have seen some minor coal investments come online, mostly as a result of high natural gas prices in the mid 2000s, and the expectation of continuing high prices. These generating units entered service around 2010, but their construction started during peak natural gas (and therefore peak electricity prices). About 70% of this new capacity (10.2GW) consisted of supercritical plants. Figure 5 shows the development of natural gas and coal-fired generation as a % of the total annual capacity addition.

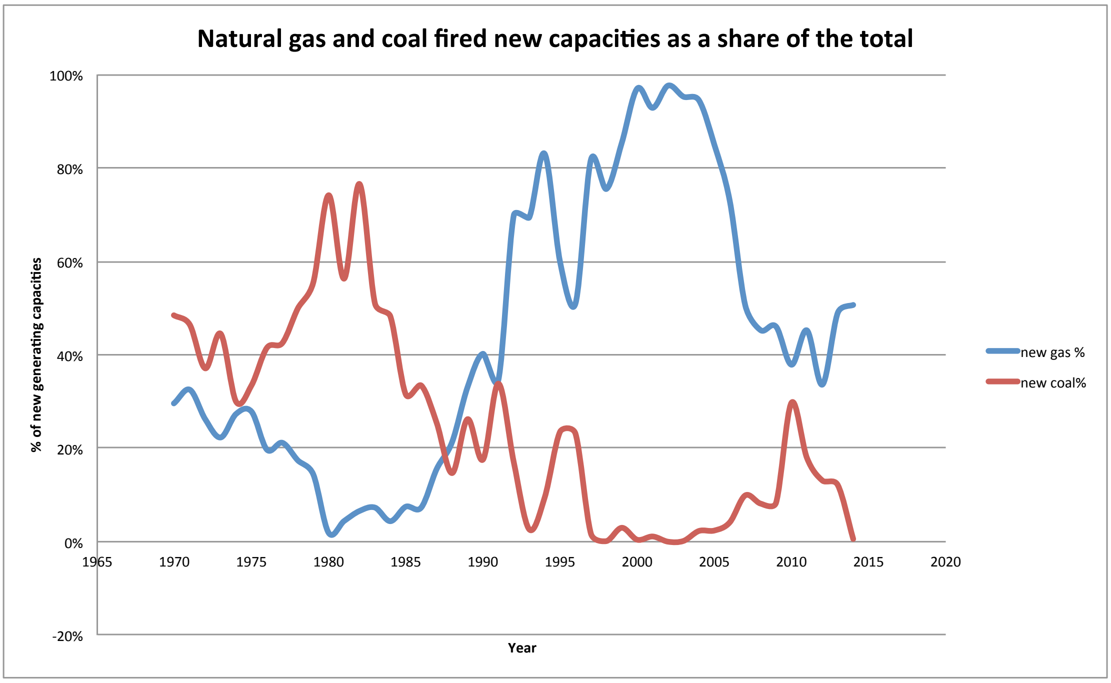

Figure 5: All natural gas and coal fired new capacities in the U.S. as a % of the total 1970-2014. Source: Form 860 - Y2014 (EIA, 2016a).

Our results indicate that while market liberalization *per se* has increased investment flows into natural gas-fired plants, higher natural gas prices under competitive regimes acted to reduce these investments further, as the relative profitability of other generation increased due to higher baseload usage, and higher margins. Also, while the average impact of liberalization was negative on coal-fired generators, natural gas prices under wholesale conditions promoted shifting investment from natural gas to other forms of electricity generation.

A condition of base-load natural gas-fired generation profitability is relatively low natural gas prices, as these prices tend to drive electricity prices and thus cost-profit margins and capacity utilization. Due to the shale gas boom, an unforeseen technological development, natural gas prices dropped close to the level of coal prices after 2010 (Figure 2), and the EIA (2016e) currently expects them to increase only moderately. However, large increases in commodity prices or in natural gas demand might see generation investment shift into more profitable facilities under wholesale market conditions. Such substitution is however not observed in traditional markets, where the return is set by the regulator.

We also examine the response of investment in renewable technologies to the above factors. We find evidence that partly liberalized markets have negatively impacted investments in solar and wind technologies. This makes sense if regulators in non-liberalized regimes drive investment by integrated utilities in renewable technologies. The coal cross price elasticity of both renewable sources is positive signaling substitution, while under wholesale markets solar photovoltaic investments still significantly benefited from increased coal prices, and reverse was true for wind turbines Also under wholesale markets, a 1% natural gas price increase has resulted in about 1.89% increased capacity into onshore wind turbines. As renewable sources have zero marginal cost, their marginal profit would have been considerably higher than those of natural gas plants in liberalized markets.

The coefficient on lagged state average GDP growth is positive and significant for natural gas technologies, and negative for solar photovoltaic. A hypothesis is that photovoltaic development might be related to stimulus spending during periods of recession. Recently added capacity has a negative effect for gas-fired generation as expected but a positive effect on coal, solar photovoltaic, and wind turbines. Retirements have mostly small and insignificant effects.

As a robustness check we also use EIA lead times for new technologies adding 1 year for planning. The results are presented in Table 1b. The key differences to the results in Table 1a are that the negative own price elasticities in non-liberalized markets for some coal-fired technologies are now significant at the 10% level. The natural gas cross price elasticity of fluidized bed coal power plants is significant at the 10% level and is positive indicating that higher natural gas prices might result in substitute investment into high efficiency coal baseload technologies in non-liberalized markets.

Table 2a presents estimates for Equation (2) and Table 2b presents the same regressions with the official EIA lead times plus 1 year planning time. In the same manner as before, observations without any capacity additions were deleted. Some minor differences to the results compared to Equation (1) include, and a negative own price elasticity of supercritical coal baseload generation after liberalization, significant at the 10%. Natural gas prices after liberalization are throughout positively associated with investments into baseload coal and online wind turbine technologies.

5. Conclusion

We find that electricity market deregulation at the wholesale level resulted in significant immediate investment in natural gas baseload technologies, and in decreased investment in coal technologies, although high efficiency baseload coal generation was less negatively, or not impacted.

We find negative own fuel price elasticities for most forms of coal and natural gas baseload investments before liberalization. There is also some evidence that higher natural gas prices might result in more technologically efficient coal generation, such as supercritical or fluidized bed plants, but not in conventional coal technologies. After wholesale market liberalization, we find that natural gas prices tend to result in reduced investments into natural gas technologies but in increased generation capacity in all forms of coal and wind turbine technologies. Often in wholesale markets, natural gas prices set the marginal price, resulting in a relatively larger marginal profit for all other technologies, but especially for renewables, operating at zero marginal cost.

The EIA (2016e) projects falling generation from coal fired electricity by 2040, with limited capacity additions, partly due to emission regulations and to low natural gas prices. Based on our results, low natural gas prices are a critical element for continued investment in natural gas fired baseload generation in wholesale electricity markets, as we do see a potential substitution effect to coal fired generation.

In summary, we show that market deregulation has a significant impact on the choice of electricity investment. In regulated cost-of-service markets fuel prices have generally less impact on the choice of the plant built, while in wholesale markets natural gas prices significantly impact on all forms of investment. Natural gas supply and prices therefore have the potential to significantly shape the power generation landscape of states with wholesale electricity markets in future.

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	(1) ngfcc	(2) ngfct	(3) csc_fb	(4) csc_pc	(5) csc_sub	(6) csc_sup	(7) nuc	(8) spv	(9) owt
Partly liberalized markets	1.971*	1.279	-0.0819	-3.316***	-2.323***	-1.408**	-0.317	-1.115**	-1.568*
	(1.004)	(0.847)	(0.229)	(0.789)	(0.587)	(0.624)	(0.275)	(0.426)	(0.853)
Fully liberalized markets	-0.547	0.283	-0.277*	0.106	0.0277	-0.214	-0.156	-0.181	0.435
	(0.418)	(0.457)	(0.154)	(0.190)	(0.199)	(0.163)	(0.203)	(0.252)	(0.373)
Lagged ln av. coal price	0.355	-0.404	0.00770	-0.621	-0.288	-0.827	-0.363	0.696***	0.568**
	(0.570)	(0.461)	(0.118)	(0.578)	(0.464)	(0.500)	(0.610)	(0.152)	(0.260)
Lagged ln av. gas price	-0.743**	-0.254	0.203	-0.343	-0.133	0.150	-0.0536	-0.403***	-0.260
	(0.295)	(0.267)	(0.128)	(0.296)	(0.282)	(0.150)	(0.243)	(0.107)	(0.170)
L.a. coal price*partly lib market	-0.655	0.698	0.154	1.156*	1.291*	0.368	-0.474	1.198***	-2.528***
	(0.861)	(0.615)	(0.251)	(0.628)	(0.689)	(0.320)	(0.369)	(0.434)	(0.540)
L.a. nat.gas price*partly lib market	-0.929	-1.659***	-0.0371	1.908***	1.156***	0.764**	0.409*	0.353*	2.159***
	(0.643)	(0.531)	(0.174)	(0.458)	(0.395)	(0.287)	(0.210)	(0.203)	(0.446)
Lagged ln av. GDP growth	15.26***	14.97***	0.850	2.205	4.279	-0.828	-1.370	-4.508**	1.898
	(3.774)	(3.287)	(1.216)	(3.099)	(3.197)	(0.997)	(2.830)	(1.905)	(2.203)
Lagged ln av. capacity added	-0.193***	-0.0273	0.0158	0.128***	0.131***	0.00946	0.0177	0.0310*	0.0815**
	(0.0522)	(0.0523)	(0.0171)	(0.0396)	(0.0424)	(0.0163)	(0.0240)	(0.0173)	(0.0386)
Lagged ln capacity retired	-0.103	-0.126	-0.0281	0.0759	0.0337	-0.0107	-0.0360	0.0833**	0.0696
	(0.0768)	(0.0962)	(0.0347)	(0.0456)	(0.0512)	(0.0232)	(0.0276)	(0.0412)	(0.0693)
Time trend	0.0865***	0.0872***	0.00315	-0.101***	-0.0894***	-0.0195**	-0.0356***	0.0246***	0.0574***
	(0.0138)	(0.0153)	(0.00322)	(0.0157)	(0.0134)	(0.00918)	(0.0121)	(0.00627)	(0.0106)
Constant	-169.6***	-171.8***	-6.467	202.8***	178.9***	39.42**	71.79***	-48.86***	-114.5***
	(27.49)	(30.46)	(6.498)	(31.31)	(26.66)	(18.54)	(24.45)	(12.45)	(21.24)
Liberalized Market Coefficients									
Lagged ln av. gas price	-1.671564***	-1.912477***	0.166	1.565005***	1.023095***	0.9135339**	0.3554941**	-0.0501396	1.898378***
Lagged ln av. coal price	-0.3005598	0.2936061	0.1615992	0.534745	1.003051*	-0.45944	-0.8369136**	1.894266***	-1.959358***
Planning and lead times	4	4	4	4	4	4	9	2	2
N	1245	1245	1245	1245	1245	1245	1056	1324	1324
adj. R-sq	0.117	0.116	0.015	0.215	0.195	0.042	0.068	0.311	0.360
Standard errors in parentheses	="* p<0.10	** p<0.05	*** p<0.01"						

Table 1a: Drivers of log capacity additions. Standard errors in parentheses

	(1) ngfcc	(2) ngfct	(3) csc_fb	(4) csc_pc	(5) csc_sub	(6) csc_sup	(7) nuc	(8) spv	(9) owt
Partly liberalized markets	1.971*	0.706	0.0945	-3.008***	-2.028***	-1.141*	-0.194	-1.671***	-0.571
	(1.004)	(0.947)	(0.222)	(0.709)	(0.453)	(0.591)	(0.284)	(0.463)	(0.793)
Fully liberalized markets	-0.547	0.430	-0.271	0.125	0.0185	-0.125	0.0193	-0.211	0.487
	(0.418)	(0.514)	(0.174)	(0.214)	(0.189)	(0.161)	(0.151)	(0.256)	(0.370)
Lagged ln av. coal price	0.355	-1.156**	0.0659	-0.958*	-0.485	-0.769*	-0.352	0.605***	0.0797
	(0.570)	(0.445)	(0.121)	(0.567)	(0.444)	(0.435)	(0.563)	(0.146)	(0.310)
Lagged ln av. gas price	-0.743**	-0.0381	0.249*	-0.278	-0.101	0.153	0.312	-0.341***	-0.0822
	(0.295)	(0.243)	(0.138)	(0.360)	(0.323)	(0.131)	(0.290)	(0.107)	(0.214)
L.a. coal price*partly lib market	-0.655	0.560	0.215	0.827	1.114	0.175	-0.288	1.354***	-2.871***
	(0.861)	(0.619)	(0.268)	(0.728)	(0.779)	(0.299)	(0.332)	(0.455)	(0.561)
L.a. nat.gas price*partly lib market	-0.929	-1.222**	-0.165	1.772***	0.997***	0.681**	0.263	0.658***	1.659***
	(0.643)	(0.587)	(0.172)	(0.471)	(0.363)	(0.295)	(0.183)	(0.225)	(0.444)
Lagged ln av. GDP growth	15.26***	11.52***	-0.405	2.436	1.516	1.205	-1.648	-4.205**	3.589
	(3.774)	(3.541)	(1.152)	(3.534)	(3.494)	(1.032)	(2.180)	(1.984)	(2.722)
Lagged ln av. capacity added	-0.193***	-0.0672	0.0240	0.110**	0.149***	-0.0130	-0.00227	0.0112	0.0374
	(0.0522)	(0.0517)	(0.0184)	(0.0471)	(0.0452)	(0.0193)	(0.0223)	(0.0212)	(0.0433)
Lagged ln capacity retired	-0.103	-0.200**	-0.0290	0.0958**	0.0227	0.0202	-0.00392	0.0976**	0.127
	(0.0768)	(0.0925)	(0.0274)	(0.0430)	(0.0439)	(0.0259)	(0.0329)	(0.0377)	(0.0787)
Time trend	0.0865***	0.0718***	0.00236	-0.104***	-0.0903***	-0.0222**	-0.0446***	0.0230***	0.0460***
	(0.0138)	(0.0135)	(0.00320)	(0.0166)	(0.0144)	(0.00855)	(0.0132)	(0.00613)	(0.0126)
Constant	-169.6***	-140.4***	-4.983	209.7***	180.8***	44.78**	89.28***	-45.72***	-91.62***
	(27.49)	(26.95)	(6.427)	(33.09)	(28.73)	(17.26)	(26.33)	(12.18)	(25.13)
Planning and lead times/(Lag length)	4	3	5	5	5	5	7	3	4
N	1245	1284	1195	1195	1195	1195	1121	1284	1245
adj. R-sq	0.117	0.116	0.021	0.207	0.186	0.044	0.060	0.314	0.372
Standard errors in parentheses	="* p<0.10	** p<0.05	*** p<0.01"						

Table 1b: Drivers of log capacity additions, EIA lead times.: Standard errors in parentheses

	(1) f_ngfcc	(2) f_ngfct	(3) f_csc_fb	(4) f_csc_pc	(5) f_csc_sub	(6) f_csc_sup	(7) f_nuc	(8) f_spv	(9) f_owt
Partly liberalized markets	0.0201*	0.00294	-0.000257	-0.0320***	-0.0274***	-0.00512***	-0.000856	0.000210	-0.00953**
	(0.0113)	(0.00428)	(0.000790)	(0.00495)	(0.00476)	(0.00188)	(0.00408)	(0.000721)	(0.00451)
Fully liberalized markets	-0.000688	0.00375	-0.000645	0.00298*	0.00364**	-0.00130	-0.00181	-0.000757**	-0.00148
	(0.00343)	(0.00253)	(0.000406)	(0.00166)	(0.00161)	(0.000983)	(0.00215)	(0.000363)	(0.00132)
Lagged ln av. coal price	0.00869	-0.00125	-0.0000764	-0.0100	-0.00616	-0.00427**	-0.00188	0.000780***	0.00203
	(0.00666)	(0.00234)	(0.000231)	(0.00822)	(0.00797)	(0.00179)	(0.00449)	(0.000277)	(0.00124)
Lagged ln av. gas price	-0.00312	-0.00366**	0.0000968	-0.00591	-0.00653	0.000752	-0.000155	-0.000606***	-0.000947
	(0.00412)	(0.00152)	(0.000123)	(0.00427)	(0.00424)	(0.000711)	(0.00373)	(0.000215)	(0.000829)
L.a. coal price*PLIB	-0.00761	0.000201	0.000195	0.0243**	0.0234**	0.00153	-0.00770*	0.00113*	-0.0107***
	(0.00828)	(0.00284)	(0.000669)	(0.0117)	(0.0116)	(0.00194)	(0.00429)	(0.000596)	(0.00342)
L.a. nat.gas price*PLIB	-0.0161**	-0.00636**	0.000157	0.0160***	0.0133**	0.00283**	0.00419	-0.000271	0.0107***
	(0.00668)	(0.00246)	(0.000427)	(0.00583)	(0.00588)	(0.00116)	(0.00302)	(0.000361)	(0.00370)
Lagged ln av. GDP growth	0.156***	0.0731***	0.00238	0.0370	0.0477	-0.00678	-0.0522	-0.00788*	0.00185
	(0.0484)	(0.0140)	(0.00289)	(0.0414)	(0.0421)	(0.00658)	(0.0448)	(0.00398)	(0.00877)
Lagged av. capacity added/lagged av. cumulative capacity	0.320**	-0.00881	-0.00126	0.0518	0.0506	0.000482	-0.000238	0.000368	0.00446
	(0.151)	(0.00643)	(0.00113)	(0.0348)	(0.0341)	(0.00135)	(0.000485)	(0.000721)	(0.00488)
Lagged average capacity retired/ lagged average cumulative capacity	-0.855**	-0.110	-0.00577	0.260*	0.266*	-0.00920	-0.0251	0.0444	-0.0893*
	(0.409)	(0.0987)	(0.0117)	(0.150)	(0.134)	(0.0410)	(0.0801)	(0.0469)	(0.0513)
Time trend	0.00152***	0.000420***	0.00000724	-0.00111***	-0.00101***	-0.000101**	- 0.000386***	0.0000273**	0.000222***
	(0.000433)	(0.0000791)	(0.00000814)	(0.000222)	(0.000213)	(0.0000416)	(0.000131)	(0.0000103)	(0.0000522)
Constant	-3.040***	-0.828***	-0.0142	2.224***	2.025***	0.205**	0.777***	-0.0538**	-0.442***
	(0.873)	(0.157)	(0.0162)	(0.445)	(0.428)	(0.0838)	(0.261)	(0.0204)	(0.104)
Liberalized Market Coefficients									
Lagged ln av. gas price	- .0192661***	- 0.0100165***	0.0002535	0.0100921***	0.0068076*	0.0035822***	0.0040349**	-0.000877	0.0097645***
Lagged ln av. coal price	0.0010755	-0.0010527	0.000119	.0142938**	0.0172755**	-0.0027438*	-0.0095774*	0.0019115***	- 0.0086513***
Planning and lead times	4	4	4	4	4	4	9	2	2
N	1245	1245	1245	1245	1245	1245	1056	1324	1324
adj. R-sq	0.287	0.111	-0.002	0.205	0.196	0.025	0.011	0.135	0.168
Standard errors in parentheses	="* p<0.10	** p<0.05	*** p<0.01"						

Table 2a: Drivers of the fraction of a specific technology's addition to the grid in state "i", time period "t" to the cumulative total installed capacity. Standard errors in parentheses

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	f_ngfcc	f_ngfct	f_csc_fb	f_csc_pc	f_csc_sub	f_csc_sup	f_nuc	f_spv	f_owt
Partly liberalized markets	0.0201*	0.00363	-0.0000541	-0.0287***	-0.0244***	-0.00419**	-0.000245	-0.000808	-0.00809**
	(0.0113)	(0.00476)	(0.000808)	(0.00495)	(0.00484)	(0.00203)	(0.00413)	(0.000510)	(0.00331)
Fully liberalized markets	-0.000688	0.00499*	-0.000543	0.00155	0.00185	-0.000855	0.000778	-0.000698*	-0.00160
	(0.00343)	(0.00271)	(0.000430)	(0.00223)	(0.00215)	(0.000959)	(0.00165)	(0.000398)	(0.00165)
Lagged ln av. coal price	0.00869	-0.00513**	0.000246	-0.0110	-0.00622	-0.00416**	-0.00369	0.000771***	-0.00114
	(0.00666)	(0.00235)	(0.000284)	(0.00869)	(0.00834)	(0.00173)	(0.00429)	(0.000280)	(0.00135)
Lagged ln av. gas price	-0.00312	-0.00154	0.000154	-0.00495	-0.00584	0.000882	0.00387	-0.000615**	0.000153
	(0.00412)	(0.00152)	(0.000225)	(0.00543)	(0.00532)	(0.000661)	(0.00351)	(0.000231)	(0.000829)
L.a. coal price*PLIB	-0.00761	0.000482	0.000316	0.0218*	0.0209*	0.000997	-0.00598	0.00146**	-0.0102**
	(0.00828)	(0.00287)	(0.000770)	(0.0118)	(0.0118)	(0.00201)	(0.00421)	(0.000663)	(0.00436)
L.a. nat.gas price*PLIB	-0.0161**	-0.00709**	-0.0000401	0.0151**	0.0126**	0.00253**	0.00329	0.000289	0.00970***
	(0.00668)	(0.00287)	(0.000427)	(0.00622)	(0.00616)	(0.00110)	(0.00252)	(0.000244)	(0.00277)
Lagged ln av. GDP growth	0.156***	0.0650***	0.000528	0.0584	0.0516	0.00937	-0.000971	-0.0100*	0.0113
	(0.0484)	(0.0158)	(0.00371)	(0.0404)	(0.0414)	(0.00634)	(0.0409)	(0.00507)	(0.0129)
Lagged av. capacity added/lagged av. cumulative capacity	0.320**	-0.000208	-0.0000638	0.00252	0.00247	-0.0000382	-0.000656	0.0000594	0.00375
	(0.151)	(0.000458)	(0.0000604)	(0.00240)	(0.00237)	(0.0000980)	(0.000867)	(0.0000433)	(0.00493)
Lagged average capacity retired/ lagged average cumulative capacity	-0.855**	-0.215**	-0.00561	0.432**	0.413***	0.0181	0.0509	-0.00539	-0.0979
	(0.409)	(0.0845)	(0.0108)	(0.166)	(0.140)	(0.0512)	(0.0831)	(0.0184)	(0.0669)
				-	-	-	-		
Time trend	0.00152***	0.000343***	0.00000944	0.00124***	0.00112***	0.000113**	0.000550***	0.0000317***	0.000178***
	(0.000433)	(0.0000697)	(0.0000106)	(0.000220)	(0.000211)	(0.0000462)	(0.000160)	(0.0000111)	(0.0000606)
Constant	-3.040***	-0.674***	-0.0189	2.494***	2.259***	0.228**	1.098***	-0.0624***	-0.354***
	(0.873)	(0.138)	(0.0209)	(0.438)	(0.421)	(0.0927)	(0.317)	(0.0218)	(0.121)
Planning and lead times/(Lag length)	4	3	5	5	5	5	7	3	4
N	1245	1284	1195	1195	1195	1195	1121	1284	1245
adj. R-sq	0.287	0.104	-0.003	0.164	0.152	0.029	0.014	0.123	0.166

="*

Standard errors in parentheses p<0.10 ** p<0.05 *** p<0.01"

Table 2b**:** Drivers of the fraction of a specific technology's addition to the grid in state "i", time period "t" to the cumulative total installed capacity, EIA lead times. SE in parentheses.