Dynamic Costs and Market Power: The Rooftop Solar Transition in Western Australia

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Abstract

Solar panels are subsidized because they displace production from polluting thermal (fossil-fuel-fired) generators. We demonstrate that solar/thermal substitution in daylight hours impacts market outcomes in other hours. This is because thermal generators must incur substantial costs to start up or ramp up production. Using estimates of dynamic cost functions for the thermal fleet in Western Australia, we estimate total fuel expenditures fell 10% over a period of rapid rooftop solar growth (2015-2018). However, revenues increased 3% from 2015-2018. Generators displaced by solar output face cost barriers to start up and compete at sunset, increasing the ability for operating generators to exercise market power.

JEL Codes: L5, L94, Q41, Q42

Keywords: Wholesale Electricity Markets, Start-up, Ramping, Dynamic Production Function, Adjustment Costs, Rooftop Solar, Intermittency

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1 Introduction

As governments around the world continue to grapple with climate change and the global and domestic politics it entails, more examples are emerging of jurisdictions promoting direct renewable energy support as their primary climate policy.[1] However, greater renewable energy penetration has been linked to higher retail electricity prices in many jurisdictions. This is because higher retail prices are often used to recover installation subsidies and feed-in-tariffs (Australian Competition and Consumer Commission, 2018, pp. 212-215); distribution network upgrades associated with the addition of rooftop solar (Wolak, 2018); and renewable energy certificates acquired by retailers to meet mandated renewable energy targets (Greenstone et al., 2019). In a static world, it would be natural to assume that *wholesale* electricity prices would decrease in response to increases in the share of electricity produced from rooftop solar panels. Specifically, rooftop solar should displace demand for electricity from the grid, which in turn would reduce production from higher marginal cost generating units and ultimately result in lower wholesale electricity prices. However, solar penetration has been observed to *increase* prices in sunset periods (Bushnell and Novan, 2018), where it is hypothesised that the lower daytime electricity demand require generators to incur greater start-up and ramping costs to service the sunset peak. This paper explores how mass-solar adoption impacts the within-day dynamics of costs and competition in Western Australia's wholesale electricity market, a region at the global frontier of rooftop solar penetration.

Policy support for solar panel installations is predicated on the environmental benefits from the energy generated by these panels displacing generation by fossil-fuel fired generating sources.[2] These thermal electricity generators require large amounts of energy to start up, and their heat rate (the ratio of fuel input to electrical output) can vary with whether output is increasing or decreasing from its current level. Consequently, both marginal costs and production efficiency are sensitive to the level of output entering and during a given time window. Therefore, the displacement of some thermal generation in the daytime could change the requirements for plants to ramp up at

[1] Examples of RECs, rooftop solar programs etc.

[2] See Borenstein (2012) for a discussion on renewable energy policy. Displacement of electricity generation is also a key component of measuring the environmental impact of electric vehicle adoption (Holland et al., 2016) and other "behind-the-meter" technology and consumption/generation changes.

sunset. As a result, the introduction of rooftop solar can have dynamic impacts on the efficiency of the thermal fleet. Although we expect daytime prices to fall in step with rooftop solar penetration, we can envisage two sources of upward pressure to wholesale electricity prices due to rooftop solar adoption: a) a decrease in the thermal efficiency of the generators that operate; and b) a decrease in effective competition if thermal generators are less frequently running and therefore must incur large start-up costs to produce and compete.

To decompose generator revenues into generating costs and gross margins, we extend the static approach of Borenstein et al. (2002) to address the Mansur (2008) critique that ignoring cost dynamics can understate costs and overstate the size of mark-ups. We map observed gas usage for each generator to past and present electrical output to identify the marginal costs of production, including start-up and ramp costs. This approach shares similarities to approaches used in the plant-level mark-up estimation literature (see De Loecker and Warzynski, 2012), however the availability of high-frequency data (30-minute) allows for start-up and ramp cost dynamics to be identified. We find that these costs are economically meaningful and can have substantial impacts on effective competition for a given market interval because they represent barriers to entry for every generator that is not in a current state of production. This direct input/output measurement is an alternate method to identifying dynamic cost functions of electricity generators using bidding behavior and a model of conduct (Wolak, 2007; Reguant, 2014), with the advantage in this context that it is easily applied to all generators in the market and identification is not dependent on a convenient set of market rules.[3]

As a world leader in rooftop solar penetration, the wholesale electricity market in Western Australia presents a textbook case of the "solar duck curve" to study the spillovers from a mass adoption of rooftop solar on the efficiency and competition among thermal generators. Further, is a small zonal market with no interconnections, allowing for a relatively straightforward study of competition.[4] The only obvious change to market conditions is the shape of system demand

[3]Further, the discussion behind Hortaçsu et al. (2019) questions whether smaller scale generator operators maximize their expected profits when deciding on their operating strategy. If this is the case, it presents a barrier to estimating cost-functions for *every* generator in the fleet using the techniques in Wolak (2007) and Reguant (2014).

[4]Conveniently, there were no major entry or exits of thermal or utility-scale renewable sources over the analysis window.

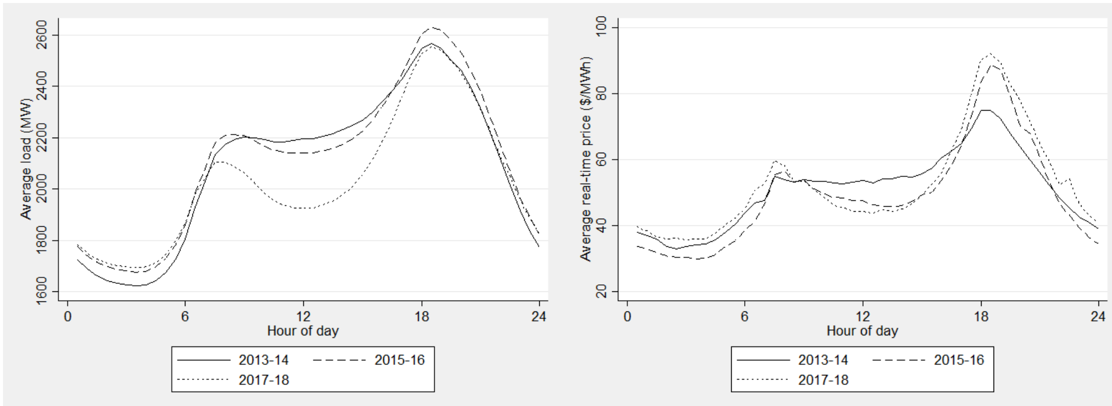
throughout the day (figure 1a). Specifically, the introduction of rooftop solar resulted in less system demand during daylight hours but very similar levels of demand for all other hours of the day. We find that during the 2015-2018 rooftop solar boom in Western Australia, where rooftop solar capacity increased 133% to levels that regularly generate more than 20% of midday load levels, the heat rate of the natural gas generator fleet increased by 1%. Despite the small drop in the production efficiency of the gas fleet, the displacement of thermal generator output by rooftop solar drove a 9% decrease in the total costs of electricity produced by thermal generators in the wholesale market. However, gross margins to thermal generators increased by 19% over that period, resulting in an overall increase in revenues to thermal generators of 3%.

The cause of the overall increase in generator revenue from 2015-2018 is tied to the impact ramping and startup costs have on competition, rather than a passthrough of incurred costs. Alongside the mass-adoption of rooftop solar are lower wholesale prices in daylight hours but higher prices at the sunrise and sunset demand peaks (figure 1b), similar to patterns documented in California (Bushnell and Novan, 2018). Further investigation reveals that for sunset hours, the average number of effective competitors decreased and consequently the slope of the market supply curve steepened over the sample window, with the growth in gross margins earned by thermal generators at sunset more than offsetting the decrease in gross margins during daylight hours. These competition features are shown to have always existed (pre-solar penetration) for days where the difference between the sunset demand peak and daytime demand trough was large, but the introduction of rooftop solar has increased the frequency of days that with a steep sunset ramp in system demand.

Our findings indicate that the technologies that can more flexibly adjust their level of output become more profitable with the mass adoption of rooftop solar. This is because there are more opportunities to exercise market power in sunset periods, and more flexible sources incur smaller start-up costs to compete during these periods. However, the overall increase in wholesale electricity prices observed in Western Australia during their rapid growth in solar adoption emphasizes some of the challenges policymakers are experiencing in the transition to a higher-renewable share of electricity generation.

First, solar adoption can impact both the costs of delivering the remaining system demand

Figure 1: Hour-of-day dynamics in the Western Australian wholesale electricity market: 2014-2018



(a) Average net load by hour-of-day

(b) Average real-time price by hour-of-day

and the competition between existing thermal fleets, potentially resulting in increases in wholesale costs. Electricity customers that do not install solar panels would pay more for their energy as a result. This price increase is in addition to the cost-recovery of any associated subsidy programs and network upgrades due to solar that are funded through increases in the retail price. With Western Australian retail prices regulated at a fixed price per kWh, customers cannot manage the timing of their consumption to insulate themselves (or benefit) from the new wholesale pricing dynamics that are emerging from the solar energy boom.

Second, our results highlight the importance of incorporating dynamics into the design of wholesale electricity markets.

The rest of the paper provides an overview for how rooftop solar penetration could impact cost, competition and price dynamics and why Western Australia is an ideal setting to study these dynamics. The data, method for estimating generator costs, and the empirical strategy for identifying cost and competition changes are presented before the results are presented and discussed. The implications of the results for flexible demand and supply technologies, along with considerations for designing electricity markets are considered before the paper concludes.

2 Conceptual framework: Impacts from rooftop solar penetration are not confined to daylight hours

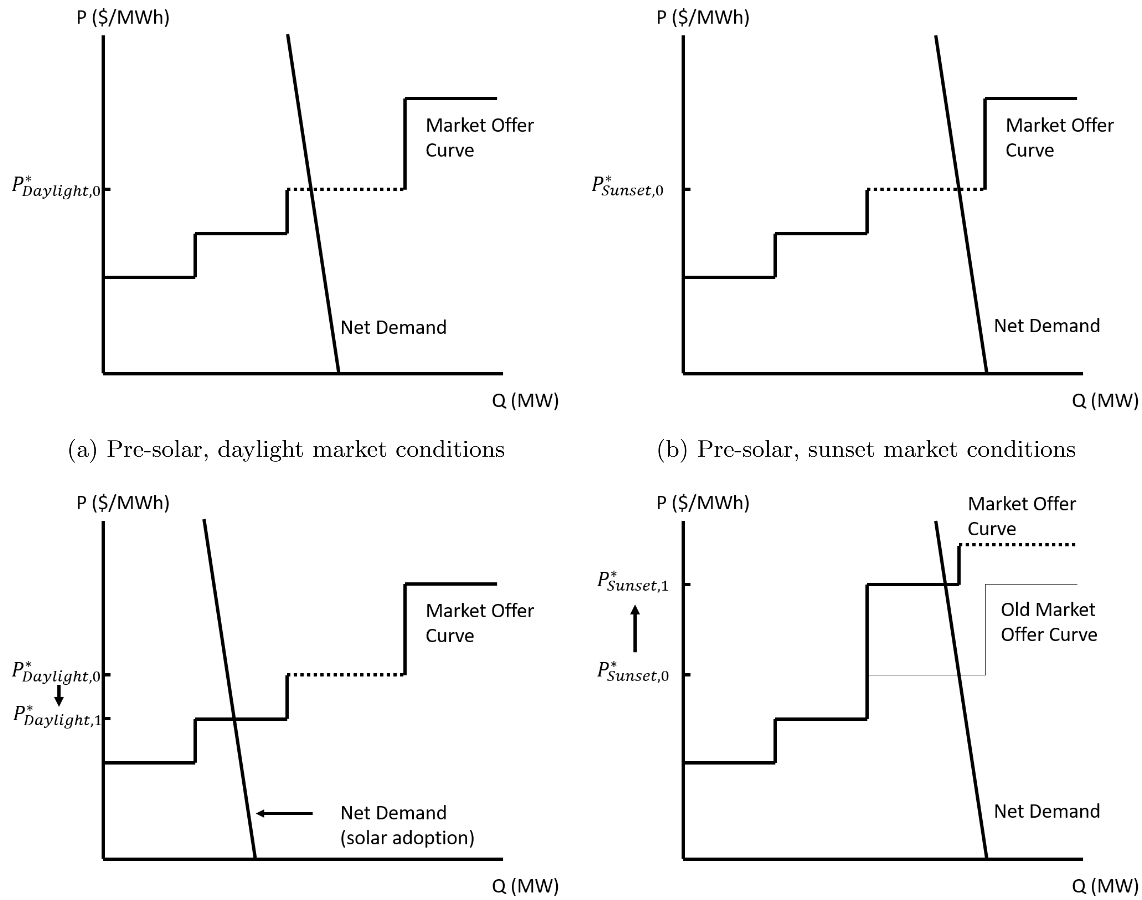
One approach to study changes in demand for electricity is to focus on merit-order effects and the marginal generating unit.[5] The rationale is that a small change in demand for energy at a given point in time will alter the costs and carbon emissions from electricity production by amounts determined by the characteristics of the marginal generator at that time. However, the speed and scale of rooftop solar adoption observed in Australia and many parts of the world can have impacts that extend beyond a static movement along the merit order.

Consider figure 2. Here we see that for a daylight hour, demand intersects with the third cheapest generator offer (figure 2a), and assuming that generator offers are unchanged for the sunset hour, demand still intersects with the third cheapest generator offer (figure 2b). However, consider the case where the third generator offer is dependent on its operating status: it will bid more competitively only if it is already running when entering a new market interval. This could be because the plant has significant start-up costs that make it profitable to start up only if the plant can recover these costs by producing across multiple hours of the day. The introduction of rooftop solar acts as a negative shift on demand in daylight hours; this results in less production of electricity, the non-dispatch of the third generator, and a lower price in the daylight hours (see Figure 2c). The third generator offers to generate at higher prices in the sunset period because it needs greater revenues to cover any potential start-up costs, and subsequently the clearing price at sunset is now higher (see Figure 2d). Therefore, performing a static marginal analysis of how market outcomes are impacted by the large and quick growth in rooftop solar might not capture important impacts across hours of the day.

The start-up and ramping costs that are required to rationalize the stylized theory in figure 2 have been shown to be significant and enter the bidding strategies of generation unit owners in other settings (Wolak (2007); Mansur (2008); Reguant (2014)). Because operating costs are dependent on previous output levels, this can also feed into the effective levels of competition throughout the

[5]See for example Holland et al. (2016), that applies marginal emission rates for locations around the U.S. to understand the environmental impacts from the growth in electric vehicles.

Figure 2: Impact of demand shift from rooftop solar on bids and outcomes during daylight and sunset



(a) Pre-solar, daylight market conditions

(b) Pre-solar, sunset market conditions

(c) Post-solar, daylight market conditions

(d) Post-solar, sunset market conditions

The third generator (dotted bid) is assumed to bid more competitively if it expects to run during both periods and can therefore recover its start-up costs. After the adoption of rooftop solar, if it does not run in the daylight hours it becomes less competitive in its bidding at sunset. Prices fall in the daylight but rise at sunset.

day. Competition at sunset hours could fall with the penetration of rooftop solar if some generators are incapable of quickly adjusting their output and the new market conditions requires a larger ramp in sunset hours. Therefore, fewer generating units operating in a given hour could mean greater market power for these units in the following hour because there are fewer plants capable of ramping up, and other plants must incur start-up costs to compete. Therefore, our analysis will explore changes in the competitive environment from the penetration of rooftop solar, in addition to the impact on generating costs.

3 Setting and Data

We study the Wholesale Electricity Market (WEM) of the South West Interconnected System of Western Australia (SWIS). This covers Perth and its surrounding cities. An attractive feature of this market for study is that it has seen large growth in rooftop solar with very little change in other market conditions since 2015 – demand growth was negligible, the existing fleet of generating facilities was stable and there are no interconnections with other markets. Further, the small scale of the market is convenient for analysis because the sizable increase in solar growth relative to system demand provides insight into how larger markets will deal with larger percentages of renewable production moving forward.

The WEM is a bid-based, multi-settlement market. Electricity generator owners submit their willingness to supply energy to the day-ahead wholesale market. The market operator collects these bids and sets the lowest price such that total market generation is equal to forecast demand.[6] Then, generators submit their willingness to supply into the balancing market. When realized demand differs from the demand forecast or generators wish to adjust their position from the day-ahead market, a subsequent balancing market determines which plants increase or decrease their planned production to ensure that demand equals supply in real-time.

About half the generating capacity in the market is owned by Synergy, a vertically integrated firm that is the monopolist retailer regulated to charge a fixed, flat price to retail customers (See table xx for a list of generating units, their characteristics and owners, and Leslie (2018) for a detailed overview). This vertical arrangement began on January 1 2014, however the primary study window is 2015-2018 to cover a window where input prices stabilized (described in section 3.2). Vertically integrated utilities with a fixed, regulated retail price are not incentivized to exercise market power to raise wholesale prices if they are a net buyer of energy because they cannot

[6]In practice, firms submit bid quantities that are adjustments their contracted position. Therefore, generators may place demand bids if they are willing to be paid to reduce output relative to their contracted quantity.

immediately pass through higher wholesale prices to their retail customers (Bushnell et al., 2008; Mansur, 2007; Leslie, 2018). For this reason, the competition analysis in section 6 will focus on both the *ability* and *incentive* for firms to exercise market power as in McRae and Wolak (2014).

3.1 Data Sources

The analysis uses data on gas usage by gas-fired electricity generators, wholesale electricity market outcomes, generator characteristics, fuel prices, and rooftop solar installations.

Actual gas usage by gas-fired generators from 1 August 2013 through to 31 December 2018 were obtained from the Gas Bulletin Board at the Australian Energy Market Operator (AEMO).[7] The usage data contains daily gas consumption by large users for a given precinct. These gas meters are matched to the generating units in the electricity market data to estimate the production technology of each generating unit (that allows for start-up and ramping costs).

Wholesale electricity market data were obtained from AEMO.[8] These data are available for each 30 minute market interval, with information available for prices (day-ahead and real-time), load (considered as inelastic demand for the remainder of the paper), and output by each generating unit. Further, generator-owner bids are available, which are either at a portfolio or generating unit level, alongside the forward contract position for the generating unit / portfolio entering the half-hour market interval. Generator characteristics were collected from annual reports compiled for the WEM market operator. These reports (Sinclair Knight Merz MMA (2014) and various issues) include estimates of generator heat rates (but not start-up and ramp costs), which we will later compare to our heat rate estimates that are recovered as part of estimating the dynamic cost function for the natural gas plants. Estimates of fuel costs for the thermal plants are constructed using these heat rates (coal) and our estimates of the production technology and subsequent fuel use (natural gas) and multiplying them by the quarterly fuel prices reported in Western Australian Department of Mines and Petroleum (2018).[9]

[7]These data can be accessed at https://gbbwa.aemo.com.au/#reports/largeUserConsumption

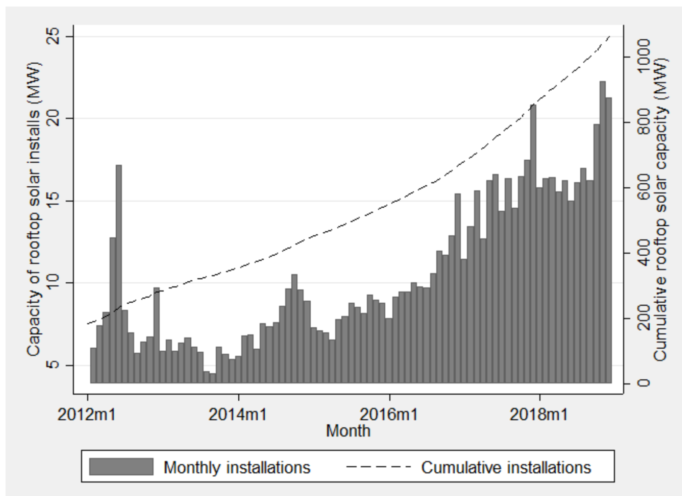
[8]These data can be accessed at http://data.wa.aemo.com.au/

[9]The fuel prices are the prices paid to the primary producers, transportation prices are not observed.

3.2 Rooftop solar penetration and wholesale market trends

Figure 3 displays the growth of rooftop solar capacity in Western Australia since 2012. There has been a 5.5 fold increase in rooftop solar capacity in 7 years. The capacity added each year has increased over the main analysis window for this paper (2015-2018).[10] Between 2015 and 2018, output from rooftop solar doubled, accounting for approximately 6.5% of all energy generated in the SWIS, and approximately 20% of all energy generated at 1pm.[11]

Figure 3: Capacity of rooftop solar installations in Western Australia



Figures 4a-4d show how electricity prices, observed heat rates for gas-fired generating units, and fuel prices moved during 2015-2018, the period of large rooftop solar penetration. To the eye, each series is relatively flat, with slight upward trends for electricity prices, heat rates and coal prices, with gas prices relatively stable with the exception of a 15% downward adjustment in 2017.

[10]This sample window was chosen to begin on 1/1/2015 because a \$24.15/t carbon tax was withdrawn in July of 2014. The impact of this event on the SWIS is documented in Leslie (2018). There was a brief adjustment period where coal prices rose following the tax increase, with fuel prices relatively stable over the 2015-2018 window.

[11]This varies across seasons, with rooftop solar accounting for 13% and 26% of all energy generated at 1pm in June and December. http://pv-map.apvi.org.au/live displays live estimates of rooftop solar output in Western Australia, using a combination of installed capacity, observed capacity factors for a subsample of systems and weather data. We calculate these statistics using this data, available via a license with APVI, merged with publicly available wholesale market data.

Approximately 50% of wholesale electricity generation is from coal plants and 40% from gas plants. With the marginal costs of gas plants reported to be higher than coal plants, they are usually the marginal unit for a given half hour, so there is an expectation that wholesale prices will be more sensitive to gas prices than coal prices. In summary, between 2015-2018:

- Wholesale electricity prices $\Uparrow$ 15% (day-ahead) and 6% (real-time)[12]
- Aggregate gas-fired generating fleet heat rate $\Uparrow$ 1%[13]
- Natural Gas prices $\Downarrow$ 17%
- Coal prices $\Uparrow$ 5%
- Rooftop solar generating capacity $\Uparrow$ 133%

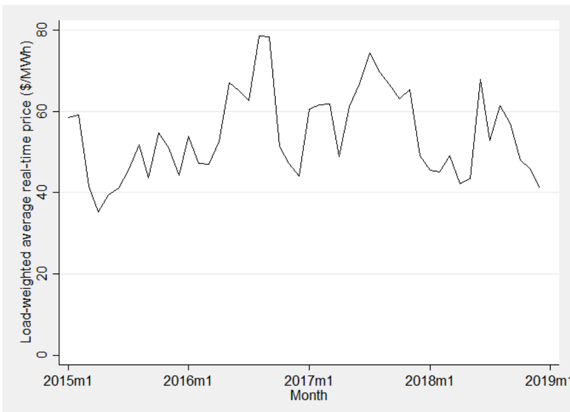
The so-called "duck curve" of system demand was observed in figure 1a, where daylight demand for energy from the wholesale market decreased in step with the inflow of rooftop solar. Figures 5a and 5b describe how output changes by coal and combined cycle gas turbines (CCGT) technologies compared to output changes from open cycle gas turbines (OCGT). Coal and CCGT plants are considered base load technologies, where they have high start-up costs but low marginal costs, whereas OCGT plants tend to have lower start-up costs but higher marginal costs. We see that the changing average load patterns are mostly absorbed by the base load technologies, however, the amount of production by these plants in the sunset hours have slightly diminished in amounts that appear directly substituted by OCGT plants.

The remainder of the paper will examine why wholesale prices in Western Australia failed to decrease between 2015 and 2018 despite the growth in rooftop solar, the decrease in fuel prices for the marginal gas-fired generating units, and otherwise similar demand conditions in non-daylight hours (figure 1a). We proceed by estimating the dynamic production technologies for the gas-fired generating units, to allow for more accurate cost estimates for the gas fleet that has been required to change their starting and ramping patterns due to the penetration of rooftop solar.

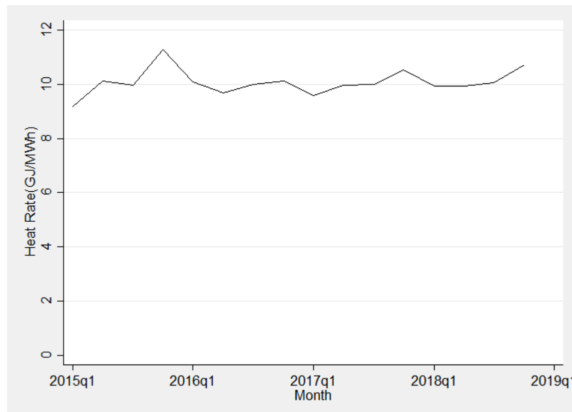
[12] Day-ahead: \$43.2 to \$49.8. Real time: \$47.4/MWh to \$50.2/MWh (load-weighted annual average over 2015 versus 2018)

[13] Compares heat rates over calendar years 2015 and 2018. Despite the upward trend in heat rates, the spike in the final quarter of 2015 heat rates dampens this growth estimate.

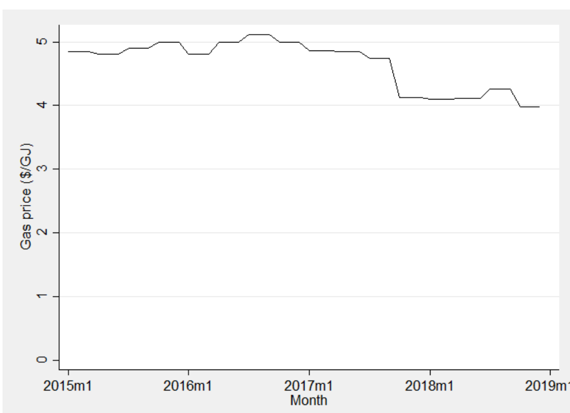
Figure 4: Electricity prices, fuel prices and rooftop solar capacity, 2015-2018



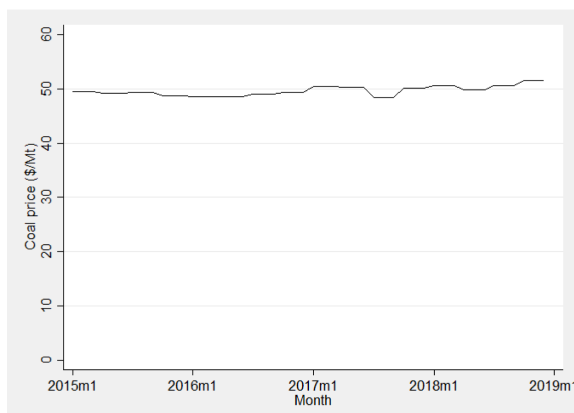
(a) Load-weighted average of real-time electricity price ($/MWh)



(b) Aggregated gas-fired generating fleet heat rate (GJ/MWh)

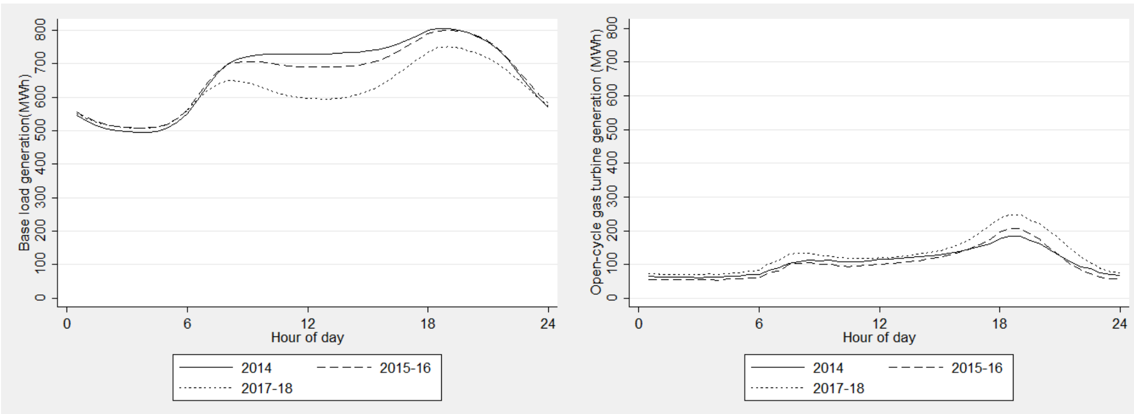


(c) Natural Gas price ($/GJ)



(d) Coal price ($/MT)

Figure 5: Hour-of-day production dynamics in the Western Australian wholesale electricity market by generation technology: 2014-2018



(a) Average production by coal and CCGT generators (b) Average production by OCGT generators

4 Estimating gas-fired generator production technologies

For each gas-fired generator hub, we observe their daily natural gas consumption. For each generating unit, we observe their half-hourly electrical output. Using these data, we can estimate the production technology converting natural gas to electricity for each plant, including their fuel use from starting up and ramping.

We begin by describing cases where there is one generating unit per gas feeder. Index each generating unit by i, half hour by t, and day by d. The raw variables are MWh of electrical output ($E_{i,t}$) and GJ of gas input ($G_{i,d} = \sum_{t=1}^{48} G_{i,t}$). We then construct three variables from the half-hourly output measures to capture the dynamics of production:

- Start-up $S_{i,t} = \mathbb{1}(E_{i,t} > 0, E_{i,t-1} = 0)$
- Ramp-up $R^{+}_{i,t} = \max(0, E_{i,t} - E_{i,t-1})$
- Ramp-down $R^{-}_{i,t} = -\min(E_{i,t} - E_{i,t-1}, 0)$

We model the production technology for a given half-hour as:

$$G_{i,t} = \alpha_i E_{i,t} + \gamma_i S_{i,t} + \beta_{i,p} R^{+}_{i,t} + \beta_{i,n} R^{-}_{i,t} + \epsilon_{i,t} \tag{1}$$

The functional form chosen is similar to that used in Wolak (2007) and Reguant (2014).[14] α_i represents the heat rate of the unit if it were to be operated at the same level of output to the previous half-hour. $\beta_{i,p}$ represents the gas usage from ramping-up production, which is additional to the gas use captured by α_i. So for an operating generator to increase their output by 1MWh from the previous half-hour, there would be an additional gas use of $\alpha_i + \beta_{i,p}$. $\beta_{i,n}$ is the analogous ramp-down parameter – for an operating generator to decrease their output by 1MWh from the previous half-hour, there would be a decrease in gas use of $\alpha_i - \beta_{i,n}$.[15] Finally, the gas usage from starting the generator is γ_i, however the total gas use from that initial half hour of operation will incur the energy and ramp up cost and equal $(\alpha_i + \beta_{i,p})E_{i,t} + \gamma_i S_{i,t}$.

To align our model of production technology with the form of the daily gas data, we sum (1) over the 48 intervals in the day:

$$\begin{aligned}\sum_{t=1}^{48} G_{i,t} =& \sum_{t=1}^{48} \left[\alpha_i E_{i,t} + \gamma_i S_{i,t} + \beta_{i,p} R^{+}_{i,t} + \beta_{i,n} R^{-}_{i,t} + \epsilon_{i,t}\right] \\ \Rightarrow G_{i,d} =& \alpha_i \sum_{t=1}^{48} E_{i,t} + \gamma_i \sum_{t=1}^{48} S_{i,t} + \beta_{i,p} \sum_{t=1}^{48} R^{+}_{i,t} + \beta_{i,n} \sum_{t=1}^{48} R^{-}_{i,t} + \epsilon_{i,d}\end{aligned} \tag{2}$$

Other physical characteristics/limitations of generators are modelled in the form of parameter restrictions:

- $\gamma_i \geq 0$: Start-ups cannot save energy
- $\beta_{i,p} \geq 0, \beta_{i,n} \leq 0$: Ramp-ups cannot save energy, ramp-downs cannot use additional energy

[14] Reguant (2014) specifies the start-up cost the same way, but along with Wolak (2007), ramp-up and ramp-down costs are symmetric, whereas we allow ramp-downs to save fuel. Both papers estimate higher order polynomials for the output terms, however for our setting we find that our linear specification is comparable to the engineering estimates we have (discussed later in the section), and that the polynomial specifications tended to be unreasonable (implying very low or negative fuel costs at reasonable levels of output).

[15] Note that $R^{-}_{i,t} \geq 0$. Therefore, the difference in gas usage when decreasing output by 1MWh is $\alpha_i E_{i,t} - (\alpha_i(E_{i,t} - 1) + \beta_{i,n}) = \alpha_i - \beta_{i,n}$.

- $\beta_{i,p}+\beta_{i,n} \geq 0$: Cannot improve production efficiency by oscillating output levels. For example, a generator operating at XMWh for two periods could not have saved energy by instead operating at $X-\delta$MWh and $X+\delta$MWh

We estimate equation (2) with the parameter restrictions by applying the appropriate exponential transformation to the parameters, estimating these transformed parameters using non-linear least squares, and using the delta method to recover the model parameters.[16] In cases where multiple generating units of the same technology are attached to a gas feeder, the model is estimated imposing a common technology so only one set of parameters are estimated. That is, equation (2) sums over equation (1) for each plant attached to the feeder. In the single case of two generating units of different technologies belonging to the same gas feeder, we estimate two sets of parameters.[17]

Table 1 reports the estimates of equation 2 for the gas-fired generating units in the market.[18] We see that estimates of generator heat rates when operating at a stable level of output (α_i) are precisely estimated, and that each plant has an additional non-zero start-up and/or ramp-up gas cost. Ramp down gas savings are found to be bounded by zero or not precisely estimated. Alongside the estimates are the assumed heat rates from a public report (Sinclair Knight Merz MMA, 2014). We see that our heat rate estimates are comparable to these estimates (which are listed as average heat rates when operating at the rated minimum or maximum). However, our econometric estimates are richer because they contain measures of start-up and ramping costs, allowing us to push the static methods used in Borenstein et al. (2002) to estimate variable fuel costs to include dynamic fuel costs from starting and ramping. Mansur (2008) demonstrates that ignoring these dynamic costs can understate costs and overestimate the rents attributable to market power.

Estimates for half-hourly gas usage for each generating unit are calculated using the point

[16] To impose the restrictions, we define $\gamma_i = exp(\theta_1)$. $\beta_{i,n} = exp(\theta_2)$ and $\beta_{i,p} = exp(\theta_2) + exp(\theta_3)$.

[17] For the Pinjar feeder, each daily gas reading is equal to the sum of the production technologies for two types of plants. $G_{i,d} = (\alpha_1 \sum_{t=1}^{48} E_{1,t} + \gamma_1 \sum_{t=1}^{48} S_{1,t} + \beta_{1,p} \sum_{t=1}^{48} R^+_{1,t} + \beta_{1,n} \sum_{t=1}^{48} R^-_{1,t} + \epsilon_{1,d}) + (\alpha_2 \sum_{t=1}^{48} E_{2,t} + \gamma_2 \sum_{t=1}^{48} S_{2,t} + \beta_{2,p} \sum_{t=1}^{48} R^+_{2,t} + \beta_{2,n} \sum_{t=1}^{48} R^-_{2,t} + \epsilon_{2,d})$. In addition, there are multiple generating units for each technology type, so $E_{1,t}$ is the sum of $E_{i,t}$ for all generating units of the first type, and $E_{2,t}$ is the sum of $E_{i,t}$ for all generating units of the second type.

[18] Gas cogeneration units are not included given that their purpose is not solely to produce electricity. Their output will be treated as exogenous throughout the later analysis.

Table 1: Engineering and econometric estimates of gas-fired generator production functions

Facility	Capacity (MW)	Engineering Est.[a] HR@min ($\frac{GJ}{MWh}$)	HR@max ($\frac{GJ}{MWh}$)	Econometric Estimates[b] HR ($\frac{GJ}{MWh}$)	Start-up (GJ)	Ramp up ($\frac{GJ}{MWh}$)	Ramp dn ($\frac{GJ}{MWh}$)
CCGT units							
COCKBURN	237 × 1	9.4	9	7.7	514.4	4.2	-0.3
				(0.014)	(87.4)	(0.98)	(0.42)
N'GEN_K'ANA	324 × 1	.	.	7.9	2873.1	1.7	-1.7
				(0.005)	(577.1)	(3.9)	(3.9)
OCGT units							
ALINTA_WGP	190 × 2	16.2	11.5	11.2	63.2	6.6	0
				(0.035)	(101.1)	(1.32)	(.)
KEMERTON	154 × 2	13.3	12.2	12.8	237.9	0	0
				(0.1)	(34.4)	(.)	(.)
KWINANA	100 × 2	15.2	9.4	9.9	0	5.6	0
				(0.035)	(.)	(0.32)	(.)
MUNGARRA	37 × 3	21.9	13.5	15.8	147	0	0
				(0.29)	(39.8)	(.)	(.)
N'GEN_N'BUP	342 × 1	.	.	11.1	452.1	0	0
				(0.226)	(351.4)	(.)	(.)
PINJAR1-7	38 × 6	22.5	13.2	13.8	168.3	0	0
				(0.373)	(31.9)	(.)	(.)
PINJAR9-11	116 × 3	19.3	12.1	15.1	577.5	0	0
				(0.033)	(18.9)	(.)	(.)

[a]: Sinclair Knight Merz MMA (2014): Engineering estimates are assumptions on the average ratio of GJ/MWh when running at the operating minimum or maximum. Engineering estimates for N'GEN_K'ANA and N'GEN_N'BUP are not available.
[b]: Estimation method described in text. Estimation sample ranges from 1 August 2013 (where gas data begins) through to 31 December 2018, and only days where gas use is observed are included in each model, therefore standard errors tend to be smaller for plants with lower heat rates because they are more frequently observed to be operating. Standard errors are calculated using the sandwich formula for the covariance matrix.

estimates reported in table 1. To place these estimates in context, table 2 reports the total observed electricity production, estimated gas usage and the amount of gas usage attributable to starts and ramps by three categories of gas generators (base load, intermediate and peaker). Start-ups and ramps are a small but significant component of incurred gas costs, representing 1%, 5% and 5% of total gas costs for each category. These incurred start-up costs perhaps understate the economic significance of these effective entry costs for non-producing generators to start-up and compete. The number of hours running per start is 93, 37 and 12 for base load, intermediate and peaker categories, in line with the incentive to operate for long sequences in time, avoiding repeat starts. Using the econometric estimates for NewGen Kwinana (base load), Kwinana (intermediate) and Mungarra (peaker), the percentage of total energy costs attributable to starting up if they were to start up and produce at their maximum capacity for a half-hour before shutting down again would be 69%, 36% and 33%.[19] Therefore, knowing the fixed characteristics of the existing fleet is not sufficient to summarize costs and competition in the market – the operating status of each generator in the fleet needs to be known. Operating generators possess a form of incumbency advantage over non-operating generators, where their competitors must incur large costs to compete in a solitary market interval. This advantage is real in practice, because thermal electricity generators can be damaged if running below their minimum operating capacity (often this is approximately 50% of their maximum capacity), so consistently generating a tiny amount of power to avoid incurring start-up costs is infeasible.

Table 2: Gas usage, electrical output and starts by technology type

	Base load (CCGT)	Intermediate (OCGT)	Peaker (OCGT)
Output (GWh)	15,061	6,552	3,962
Gas use (TJ)	119,820	71,442	61,907
Start + ramp gas use (TJ)	1,530	3,694	3,124
% Gas used on starts + ramps	1%	5%	5%
Hours running per start	93	37	12

ALINTA_WGP, KWINANA and N'GEN_N'BUP are classified as intermediate generators, having heat rates between the CCGT base load plants and the remaining OCGT generators that tend to be run less frequency and have lower maximum capacity. Figures reported are totals, ratios or percentages from years 2013 through 2018.

[19] This operating pattern is strictly illustrative, as it might take a unit additional periods to reach their rated capacity. Ratio calculated is $\frac{\widehat{\gamma_i}+\widehat{\beta}_{i,p}CAP_i}{\widehat{\gamma_i}+(\widehat{\beta}_{i,p}+\widehat{\alpha}_i CAP_i})$, where CAP is the maximum capacity in MW divided by two to represent the energy generated in a half-hour.

5 Fuel costs and gross margins

Decomposing changes in wholesale market revenues earned by generators into fuel costs, competitive rents and market power rents to study market performance was introduced in Borenstein et al. (2002). The standard approach to estimating fuel costs assumes a static production technology, where engineering estimates of generator heat rates are multiplied by the spot price of coal or gas. In this section we extend this method by applying our dynamic fuel cost estimates for natural gas plants to each observed half-hour interval to better understand the daily patterns for how fuel usage has changed alongside the increased rooftop solar penetration.

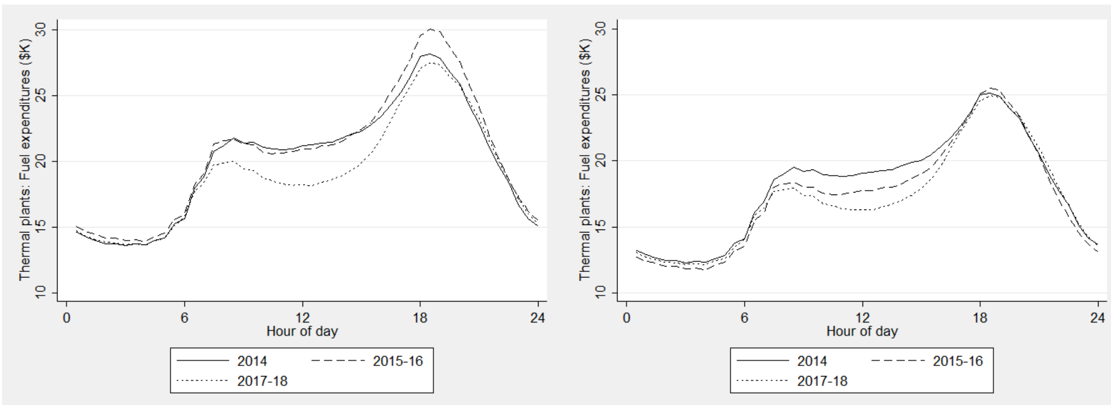
For the analysis that follows, we restrict our analysis to the strategically-operated generating units that make up 73% of energy generated in the WEM over 2015-2018. This includes coal units (where by necessity we use static heat rate estimates from Sinclair Knight Merz MMA (2014) to calculate their fuel usage) and the gas units listed in table 1.[20] Given that gas units have significantly higher marginal costs than coal units, changes to within-day dynamics are expected to impact the gas-fired fleet because these units are most often marginal.

We note two caveats. First, like Wolfram (1999) and Borenstein et al. (2002), we do not directly observe other operating and maintenance costs associated with electricity generation. We do not model these costs in the analysis. Further, fuel costs do not include transportation components and fuel contracts are not observed. Consequently, the gross margins we calculate will be estimates of revenues less fuel expenditures, which is not equivalent to operating profits. However, changes in gross margins are likely to correlate strongly with changes in operating profits if the omitted costs are stable across time. Second, to calculate competitive rents, we need a notion of the marginal generating unit for each interval and their marginal cost. Given the dynamic focus of the analysis, where a generating unit that increases their output in the current market interval can impact their costs in the next interval, we separate revenues into fuel costs and gross margins and refrain from separating gross margins into competitive and market power rents. Instead, to examine market power changes over the study window, we will focus on the offer curves submitted into the market,

[20]The excluded output is from utility scale solar, wind, biomass and gas cogeneration units, essentially treating their output as negative demand.

outlined in the next section.

Figure 6: Hour-of-day cost dynamics in the Western Australian wholesale electricity market: 2014-2018



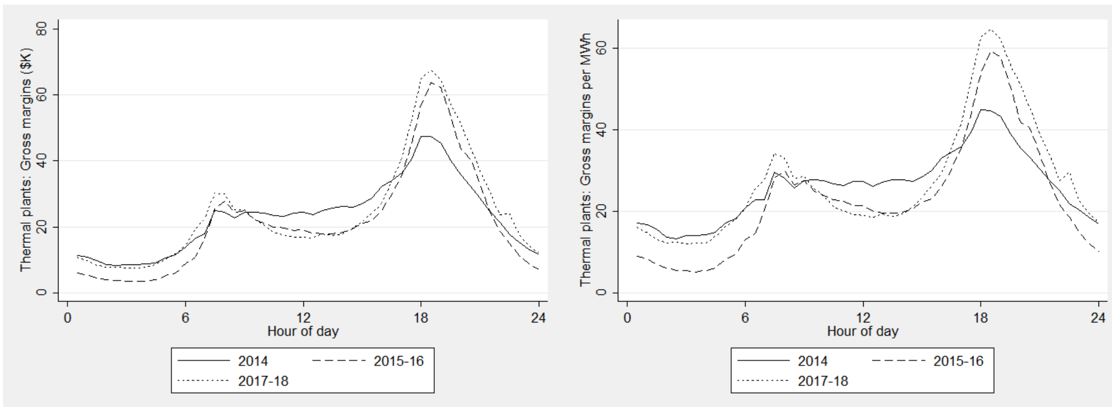
(a) Average fuel expenditures for thermal fleet

(b) Average fuel expenditures for thermal fleet, fixing fuel prices to 2013 levels

We see in figure 6a that the average costs of generation have actually fallen between 2015-2018 throughout most hours of the day. To obtain a more complete picture, figure 6b displays average fuel costs across the day, holding fuel prices at 2013 levels, revealing that fuel use has been dropping during the middle of the day (as more rooftop solar displaces the need for energy from thermal sources), but average fuel use for the fleet is unchanged at the sunset peak. Given that we saw earlier in figure 1 that average demand at the sunset peak has not been changing but prices have been increasing, this can only mean that generator gross margins increased at sunset over our study window. Subtracting the estimated fuel costs from the total payouts thermal generators would receive if they were paid spot prices (output multiplied by the real time price) gives us a measure of gross margins earned by the thermal fleet. Figure 7a confirms this assertion that gross margins have increased at sunset, with figure 7b highlighting that the increase in gross margins has occurred on a per MWh basis.[21]

[21]Given that the thermal plants we included in this analysis represents 73% of total wholesale production, the per MWh chart demonstrates that the driver behind gross margin growth is prices, not a change in the composition of included and excluded plants output throughout the day.

Figure 7: Hour-of-day gross margin dynamics in the Western Australian wholesale electricity market: 2014-2018



(a) Average gross margins for thermal fleet

(b) Average gross margins per MWh for thermal fleet

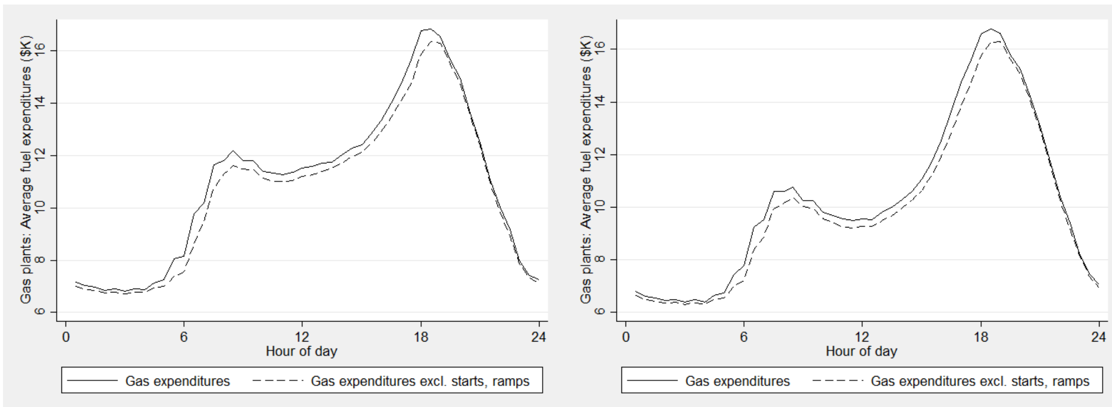
The conceptual framework and the econometric estimates of gas-fired generator fuel consumption concluded that a decrease in middle-of-day generation but a consistent level of sunset generation could result in a greater amount of incurred start-ups. Figures 6a and 6b displayed fuel expenditures, where all incurred start-up and ramp costs were reported in the period they were incurred (no smoothed over all operating hours). In line with table 2, we see that starts and ramps contribute a small amount to incurred fuel expenditures for gas-fired generators in figures 8a and 8b. The average amount of start-up and ramping costs has not noticeably changed for any hour of the day between 2014 to 2018, however, these costs are larger as a proportion of all fuel costs for the middle-of-day hours. These figures motivate a deeper competition analysis that relates the start-up and ramping costs to entry barriers, because it is not clear that the observed price dynamics are caused by a direct passthrough of higher incurred start-up and ramping costs.[22]

To summarize the changes in fuel expenditures and gross margins from 2015-2018, aggregating over all hours between the calendar years of 2015 and 2018, we find that:

- Total payments to thermal generators increased $21m (3%)

[22]We note our earlier caveat that our gross margins measure does capture operating and maintenance expenditures, which we assume are small and consistent over time.

Figure 8: Hour-of-day fuel expenditures with and without start-up and ramping costs for the gas-fired fleet (2013 prices)



(a) Average fuel expenditures for gas-fired fleet, 2014 (b) Average fuel expenditures for gas-fired fleet, 2018

- Total fuel costs incurred by thermal generators decreased \$34m (-10%)
- Total gross margins to thermal generators increased \$55m (19%)
  - Gross margins to coal increased \$9m (3%)
  - Gross margins to CCGT gas increased \$17m (77%)
  - Gross margins to OCGT gas increased \$29m (>1000%)

Despite the changing system demand curves and falling gas prices leading an apparent reduction in production costs for thermal generators from 2015-2018, their revenues and consequently margins increased. The decrease in gross margins during daylight hours were more than offset by the increase in the sunset hours. Not surprisingly, the OCGT generators that were observed to increase their average output at peak times have benefited the most from the changing market conditions, but the smaller increases in profitability for the base load technologies is somewhat more surprising given their output reductions.[23] The inframarginal plants that continued to operate over the years have

[23] The percentage increase for CCGT plants is because they had much tighter gross margins in 2015 than the coal plants

seen improved profitability as they also collect a share of the producer surplus at peak hours that offsets the loss of revenue during the daylight hours.

6 Competitive responses to daytime demand troughs

Incurred fuel costs at sunset have not substantially changed with the penetration of rooftop solar in Western Australia, but wholesale prices and gross margins have increased. This points a change in the nature of competition. We use a similar framework to McRae and Wolak (2014) to study changes in the ability and incentive for generators in the wholesale market to exercise market power. Electricity generators are considered to submit their bids into wholesale markets to maximize the following objective function:

$$\max\ P(q_i).(q_i - q_i^f) + P^f.q_i^f - C(q_i)$$

Here, q_i is their realized generation with cost function $C(q_i)$, q_i^f is their forward position supplied at a price P^f that is fixed entering the spot market, an $P(q_i)$ is the wholesale market price, to which the generator may have the ability to impact.

Define the inverse semi-elasticity of residual demand facing the firm as $\eta_i = -\frac{1}{100}P^*\frac{\partial P^*}{P^*}/\frac{\partial q_i^*}{q_i^*}$. Insofar as the firm's bidding strategy determines its equilibrium output and $P(q_i)$ is known, the profit maximizing condition for the firm is:

$$P - C' = 100\eta_i^C$$

$$\text{where } \eta_i^C = \eta_i\frac{q_i^* - q_i^f}{q_i^*}$$

In the terminology of McRae and Wolak (2014), η_i captures the *ability* for a firm to exercise market power, representing the \$/MWh increase in the spot price from a 1% reduction in the firm's output. η_i^C is interpreted as being related to the *incentive* for a firm to exercise market power, representing the increase in the spot price from a 1% reduction in the net-of-contracts position of the generator.

The incentive for the firm to raise prices decreases with the size of the firm's forward position.

Empirically, these objects are easily constructed using data containing the bids generators submit to either the day-ahead or real-time market, with the derivatives numerically estimated.[24] Further, a feature of the WEM market data is that contract positions are submitted to the market operator before the day-ahead market is held, allowing q_i^f to be observed.

To give market aggregates of these ability and incentive measures to exercise market power, we analyse for the day-ahead market (with real-time analogues revealing similar insights):

- N: The number of generating units that output energy in the market interval
  - A measure of the effective competition in the market, as generating units not running must incur start up and ramping costs to compete in the next market interval
- η: The inverse semi-elasticity of supply $(-\frac{1}{100}P^*\frac{\partial P^*}{P^*}/\frac{\partial Q_S^*}{Q_S^*})$
  - Captures the ability for any firm to increase prices
- $q_M^* - q_M^f$: Output exceeding the forward contract quantity for the merchant generators
  - This excludes the vertically-integrated Synergy, that owns approximately 50% of generating capacity in the market. Synergy charges retail customers a regulated fixed-price for energy, and effectively buys all energy generated on the wholesale market.[25]
- η_M^C: The inverse semi-elasticity of net-of-contracts residual demand for the merchant generators
  - Although the incentive for each individual merchant generator will differ, this aggregate measure reveals whether the merchant generators are long or short on their forward positions and the slope of the residual demand they face from Synergy's bids.

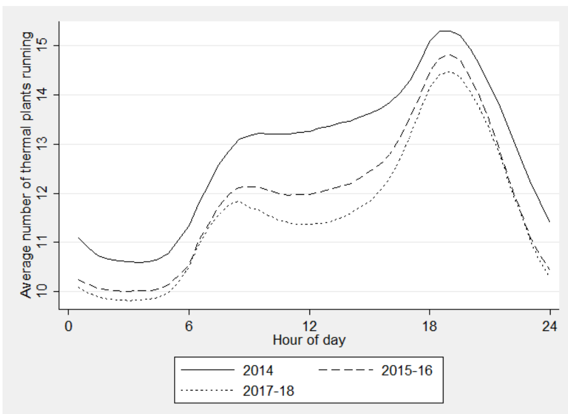
Levels of effective competition have fallen since 2014, with less thermal generators entering sunset peaks in an operating status (figure 9a), while the average ability to raise prices has increased

[24] We follow McRae and Wolak (2014) and Leslie (2018) and take prices at $0.9q_i^*$ and $1.1q_i^*$ to estimate the derivative.

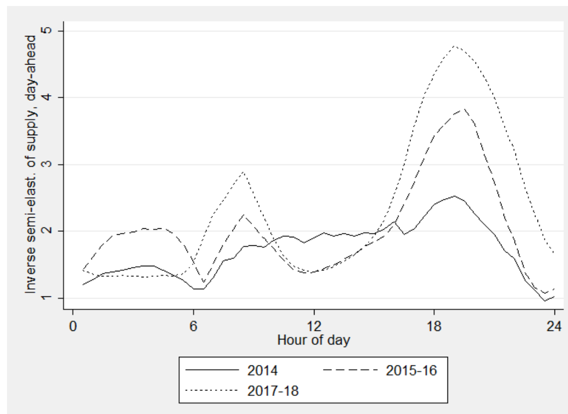
[25] Synergy effectively buys all generation from the wholesale market, Q^*, so its objective function is max $P(q_i).(q_i - Q^*) + P^R.Q^* - C(q_i)$

substantially at sunset, reflecting a steeper supply function that has doubled the impact a reduction in output has on prices from 2014 to 2018 (figure 9b). Although the ability to raise prices has increased at both sunrise and sunset, we see that the incentive for merchant generators to do so is on average confined to sunset, with merchant firms increasing their average level of output exceeding their contracted positions (figure 9c) and their inverse net-of-contracts semi-elasticity of residual demand (figure 9d).

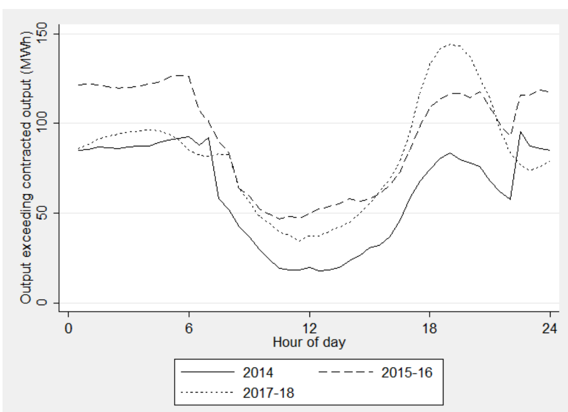
Figure 9: Measures of ability and incentive to exercise market power, 2014-2018



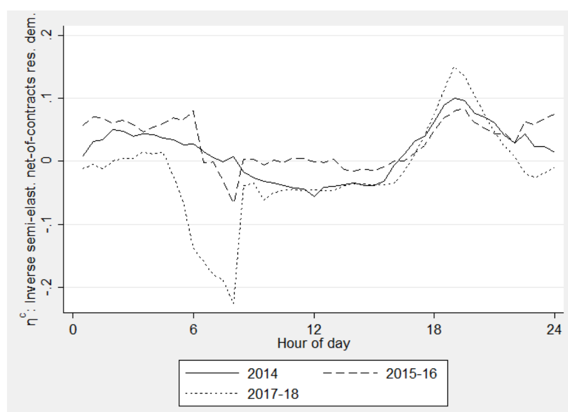
(a) N: Number of generators that output energy in the market interval



(b) η: The inverse semi-elasticity of supply



(c) $q_M^* - q_M^f$: Merchant generator output exceeding forward contracts



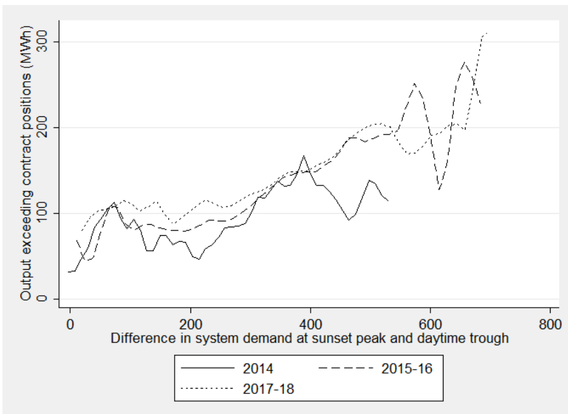
(d) η_M^C: Merchant generator inverse semi-elasticity of net-of-contracts residual demand

The large growth in gross margins at sunset over the recent rooftop solar boom are accompanied by increases in both the ability and incentive for merchant generators to exercise market power. If there is a link between rooftop solar adoption and the levels of effective competition at sunset, it must be related to the size of the system ramp from the daytime trough to the sunset peak. As indicated in our stylized theory, a deeper daytime trough will mean that less generators are running in the day, requiring offline generators to incur large start-up and ramp costs to compete at sunset, giving the incumbents more market power than if system demand were to be constant throughout the day.

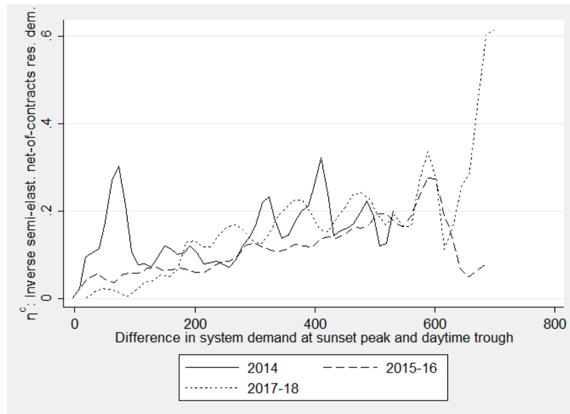
In figure 10, we display the relationship between the market power measures at sunset and the size of the daily ramp (the difference in system daytime trough to sunset peak). Two features stand out. First, gross margins to thermal generators, alongside merchant generator net-of-contracts output and inverse net-of-contracts semi-elasticity of residual demand are increasing in the size of the system ramp (figures 10a-10c). Therefore, the incentive for firms to exercise market power at sunset, and the amount of rents they can capture, is driven by the size of the system ramp, something that increased solar penetration can exacerbate. Second, these relationships have not meaningfully changed from 2014 through to 2018. Therefore, the impact of rooftop solar penetration is not on fundamentally changing the conduct of firms to system ramps, rather it has simply changed the distribution of the daily system ramps (figure 10d). Some previously low ramp days are now moderate ramp days, moderate ramp days are now high ramp days and some high ramp days are now at magnitudes that were never previously observed before the introduction of rooftop solar.

The link between market power at sunset and the size of the daily ramp provides insight into the conditions where solar penetration will result in higher or lower wholesale prices. If solar generation exacerbates the system ramp, we can expect prices to fall in the daytime, but for prices to rise in sunset. However, if the system ramp is shaved by solar penetration, prices would be expected to fall throughout the whole day. The introduction of rooftop solar in Western Australia has led to much different load shapes in Summer and Spring (figures 11a and 11c). In Spring (also in Autumn and Winter), the so-called duck curve is more pronounced, with steeper declines in system demand from the morning peak and steeper inclines to the evening peak. This pattern has been

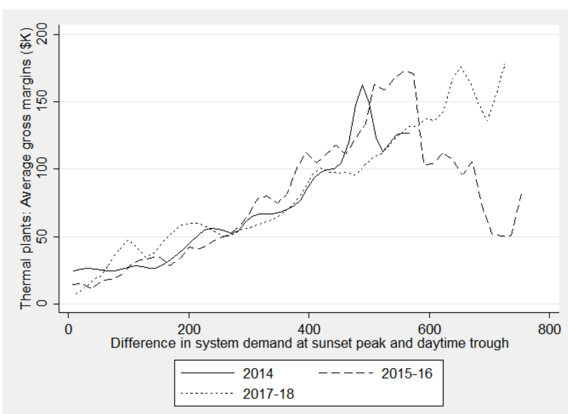
Figure 10: Means of market power measures at sunset peak, conditioned on daylight to sunset system ramp, 2014-2018



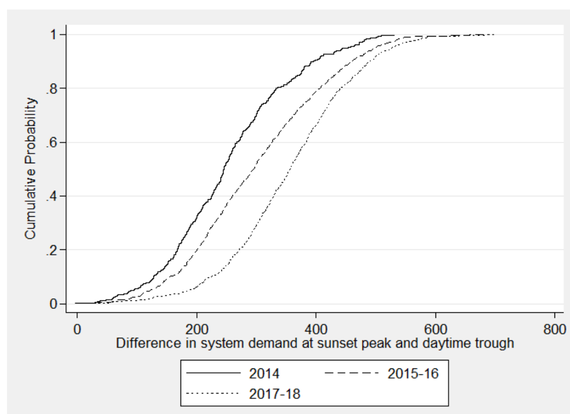
(a) N: Merchant generator output exceeding forward contracts



(b) η_M^C: Merchant generator inverse semi-elasticity of net-of-contracts residual demand



(c) Gross margins for thermal fleet



(d) Histogram of system demand ramp (MW)

Non-parametric conditional mean function (Gaussian kernel) plotted. The ramp variable is constructed as the difference between the highest system demand (defined as the MWh of thermal output in a half-hour) in the evening and the lowest system demand in the daytime.

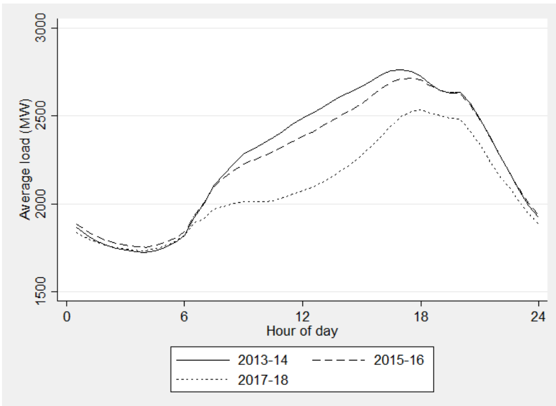
the focus of the paper and subsequent discussion and interpretation. However, these patterns mask the impact in Summer, where system demand steadily increases from morning until the evening peak. The growth in solar capacity has dramatically shaved the morning peak and ramp, while shaving the evening peak, attenuating the differences between the peaks and troughs. Wholesale prices have been decreasing from 2014 for the daylight hours, with only a small increase in sunset prices observed in the final year of data where the slope of the system demand ramp finally started to steepen (figure 11b). It is a different story in Spring, where the impact of solar growth on the daytime trough has exacerbated the trough to peak ramp, and wholesale prices have become much higher at sunset (figure 11d). Despite solar generation undoubtedly being lower in Spring than Summer, the dynamic impacts from solar appear to be greater during Spring as solar amplifies the already large peaks and troughs in system demand.

7 Discussion: Cost dynamics and electricity market design

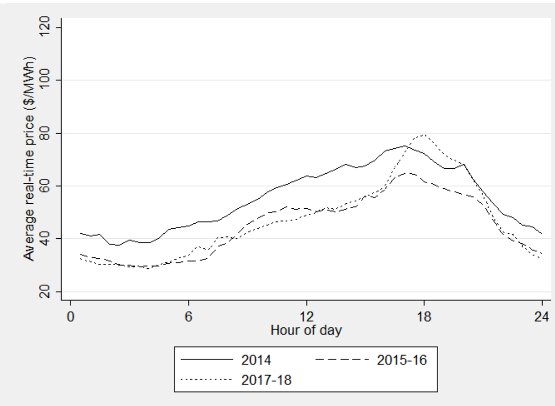
We interpret the results in this paper to suggest two things: 1) the value of flexible demand and supply technologies is only increasing with more solar capacity being added to electricity grids in temperate regions; and 2) consumption or generation actions can impact system costs in other periods, emphasizing the benefits of multi-settlement market designs, whereby the day-ahead market solves to minimize as-bid total system costs for multiple periods at once, instead of each period independently.

For the first point, we know that all else equal, adding more solar will continue to lead to lower daytime prices (and lower revenues for individual solar owners if they are paid wholesale prices). However, the short-term dynamics observed in Western Australia for such a large rooftop solar push has highlighted that prices are increasing at the sunset peak. At present, the incumbents best placed to profit from the new market conditions are OCGT generators as they can more readily ramp up and down to match the changing load patterns. Unfortunately for customers, this has meant in the short-run that they have paid higher wholesale prices (in addition to any subsidy program recover baked in to their retail prices). However, these wholesale price patterns should

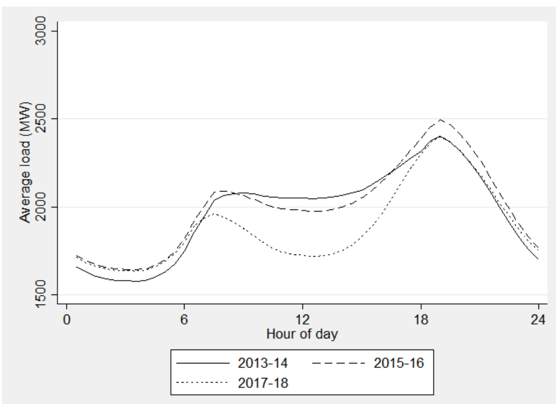
Figure 11: Rooftop solar penetration: Change in market outcomes by season



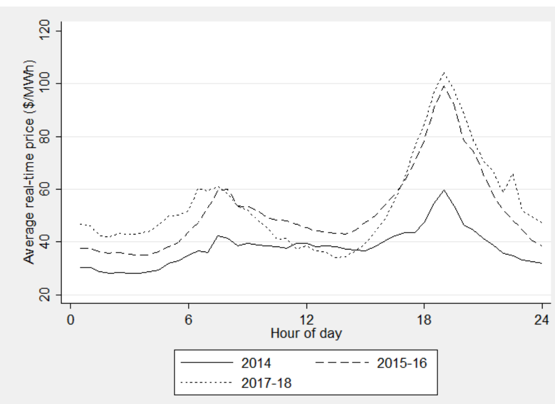
(a) Summer: Average net load by hour-of-day



(b) Summer: Predicted change in wholesale prices per additional MW of rooftop solar capacity



(c) Winter: Average net load by hour-of-day



(d) Winter: Predicted change in wholesale prices per additional MW of rooftop solar capacity

encourage entry from storage owners, that can buy cheaper energy in the day time and sell it for more in the evenings. Further, any consumer that can be flexible in their consumption patterns can greatly benefit from shifting evening consumption to the middle of the day if an arrangement can be made where they face real-time prices. In sum, the results show the need for policy makers and regulators to get ahead of the curve in jurisdictions with renewable power growth to remove barriers participants that can be flexible in their consumption and generation pattern, be it storage owners or end-users. Reforms to allow more active participation in wholesale markets by storage owners and consumers may have a substantial efficiency impact.

The second point adds our findings to the observations in Wolak (2007), Mansur (2008) and Reguant (2014) that thermal electricity generators have non-convex production functions, and the implications this has on market design.

Hogan (2014); Wolak (2017); Cramton (2017) and Federal Energy Regulatory Commission (2002) discuss how efficient pricing in electricity market necessitates that energy prices vary across location and time. The location component is built in to nodal markets. However, if markets are single-settlement, then the optimization problem is solved separately for every half-hour interval, putting the requirements on generator owners to strategically manage the dynamic problem in a series of repeated, static auctions. Multi-settlement markets allow for the market operator to solve for the minimum as-bid total system cost across interdependent periods in the day-ahead market. Therefore, the production schedules for each market interval are simultaneously solved, and the prices reflect the gradient on the objective function, therefore reflecting any dynamic impacts of consumption or production on total system costs.[26] These dynamic impacts can be considered either by eliciting generator ramp rates (a generator hitting its ramp rate in an interval is not marginal and therefore will not be setting the price) or start-up costs, or daily revenue requirements. Most multi-settlement markets (including the SWIS) require generators to include maximum ramp rates in their bids, although it is less common to allow daily revenue requirement bids to be placed (the Iberian electricity market is an exception, see Reguant (2014)). Further analysis on the merits behind the different bid structures that signal dynamic costs may be warranted to ensure that the market design rewards (penalizes) bids that have positive (negative) dynamic impacts on system generating costs, where current period dispatch lowers (raises) future period operating costs.

[26]Introducing virtual bidding by financial participants that can profit from predicting day-ahead and real-time differences can help converge day-ahead outcomes toward real-time outcomes. These better predictions can result in lower-cost scheduling and therefore, efficiency gains (Jha and Wolak, 2019).

8 Conclusion

All else equal, the impact of rooftop solar penetration on average system demand throughout a day is to decrease system demand during the daytime. In temperate climates that exhibits a morning and evening peak at around sunrise and sunset, the distance between the peaks and troughs are increased, requiring a greater system ramp. We found that in Western Australia, this changing load pattern coincided with increased wholesale electricity prices at these peaks, and lower prices in the daytime trough.

The mechanism for these price changes is linked to the characteristics of the thermal generating stock. Flexible generators that can ramp up and down more easily have seen increased use and base load generators have seen slightly less use at peak times. Consequently, the marginal costs of generation have increased at these periods. However, the main driver of the price changes appears linked to competition. The dependence of generating costs on its operational status entering a market interval (starting up from cold is costly), means that the diminished middle-of-day demand has resulted in less plants already running, meaning that there are less generators capable of ramping up and competing.

The wholesale market consequences for Western Australia from their fast and large-scale rooftop solar growth has been beneficial to most existing generator owners but not for consumers in the short run. Despite production costs falling for thermal generators (they produce less during the day), their revenues have increased due to much higher peak prices because of the competition impacts. Therefore, on top of any subsidy and feed-in-tariff cost recovery built in to retail prices, relief has not come from wholesale procurement costs for customers. Policy support for rooftop solar is one of many second-best approaches to climate policy, where the ideal is still to target the externality directly by taxing greenhouse gas emissions. If solar-promoting policies are more politically palatable than carbon pricing, the upward pressure on electricity prices from solar penetration that was observed in our analysis might be making the already challenging campaign for carbon pricing an increasingly difficult sell.

The lessons from Western Australia are two-fold. First, in settings with a morning and evening peak, large-scale solar penetration is likely to depress middle-of-day prices and increase peak prices. This means that flexible participants on either the supply or demand side of the market should see their business cases improve. In such markets, regulators should prioritise removing barriers to entry for these technologies as their entry could improve the efficiency of the market.

Second, electricity market designers should ensure the dynamic impacts of consumption/production are recognized in the market design and are reflected in prices. Changing load shapes can impose costs or benefits to meeting system demand by either inducing more or less ramping and cold starts. The current design of Australia's National Electricity Market (that is much larger than the Western Australian market) pays producers the marginal as-bid system cost of withdrawing energy from their location each period independently. By introducing multi-settlement markets (and perhaps allowing generators to submit daily revenue requirements), there may be better designs that incorporate the dynamic cost impacts of production into the price incentives generators face. Efficient price signals across time and location will only grow in importance as more intermittent sources are added to the grid.

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