The Impact of Generation Mix on Australian Wholesale Electricity Prices

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Abstract *This paper examines the impact of generation mix, encompassing fossil fuels (black and brown coal and natural gas) and renewables (hydropower and wind power) on daily spot electricity prices across the five regional electricity markets in the Australian National Electricity Market from January 2006 to June 2012. The objective is to gain insights into the emergent effect of government policy and industry developments regarding the choice of generation on wholesale electricity prices. Using least squares and quantile regressions, we find that the changing generation mix used for producing electricity exerts a strong influence on wholesale prices. This is especially the case with prices expected to increase markedly with the increasing utilization of gas-fired generation used to support the intermittent and variable production from renewables and from the policy driven use of renewables wind power associated with the current renewable energy target and carbon taxation in Australia.*

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Keywords: electricity supply, generation mix, greenhouse gas emissions, carbon taxes, renewable energy target

1. Introduction

Endowed with substantial reserves of black and brown coal, the Australian electricity industry has historically, and almost completely, drawn on solid fossil fuels to provide its electricity. However, recent growth in gas-fired electricity generation has surged alongside the discovery of new and larger gas reserves. Elsewhere, renewables have been largely restricted to hydropower. However, as there are no plans for new large hydroelectric projects in Australia, wind energy production has emerged as a primary and growing source of renewable energy.

It is generally accepted that greenhouse gas emissions policy in Australia will drive the long-term development of low-emission generation capacity (currently hydropower and wind power) with a movement away from high-emission generation (black and brown coal and, to a lesser extent, natural gas). However, there is substantial uncertainty over the timing and technical feasibility of these changes with it being likely that coal will remain the most important base load fuel for some time with gas called upon to complement the variable and intermittent output from wind. It is also clear that wholesale prices will increasingly respond to the varying cost structures of these technologies and the fuels used in generation.

The purpose of this paper is to gain insights into the effect of these very long-term changes in generation mix on wholesale electricity prices. Fortunately, the Australian market comprises distinct regional markets, each characterized by its own peculiar generation mix. Using panel data techniques and high-frequency data, we provide meaningful estimates of the effects of generation mix using both the substantial cross-sectional variation in these regional generation mixes and the time-series variation in their development. The structure of the

remainder of the paper is as follows. Section 2 describes the data and method used. Section 4 contains the results. Section 5 concludes.

2. Method

We use two sets of data in this analysis. The first consists of daily spot electricity prices (in \$/MWh) and demand (in tens of thousands of MWh) from 1 January 2006 to 6 September 2012 for each of the five regional markets, comprising New South Wales (NSW), Queensland (QLD), South Australia (SA), Tasmania (TAS), and Victoria (VIC), in the National Electricity Market (NEM). These data are from the Australian Energy Market Operator (AEMO, 2015). The second set is daily generation by generation type, the available capacity for each generator and the inter-regional flow, all from Global Roam (2015). Daily generation for each regional electricity market comprises black and brown coal, gas, and hydropower and wind power generators (all in MWh). Table 1 presents descriptive statistics of all variables by region and as a whole for the NEM.

<INSERT TABLE 1 HERE>

The dependent variable in our model is daily wholesale spot electricity prices (*PCE*) for each region. The first two independent variables specified are the lagged price and contemporaneous volume of demand (*DMD*). We hypothesize a positive sign when contemporaneous volume of demand is regressed against price, that is, price will increase with the level of demand. The next group of independent variables reflects the alternative technologies used for electricity generation and their impact on price. We aggregate daily generation in each region into five types comprising black coal (*BKCL*), brown coal (*BNCL*), combined-cycle gas turbines (*CCGT*), open-cycle gas turbines (*OCGT*), hydropower (*HYDR*) and wind power (*WIND*) expressed as a proportion of total regional generation.

The impact of these various technologies on spot prices will vary according to their capital costs and the marginal costs of production. As a rule, capital costs (including waste disposal) tend to be low for fossil fuels and high for wind power and hydropower, while fuel costs as the main component of marginal costs tend to be high for fossil fuels and near-zero for most renewables. On this basis, we expect that the increased use of coal will be associated on average with lower spot prices, moderate to high spot prices for CCGT, hydro and wind, and high to very high prices for OCGT.

The next group of variables are included to proxy other demand and supply impacts on spot prices. The first is the daily interregional energy flow (*FLOW*) in 100 MW for each region, which is positive (negative) if the region is exporting (importing) energy. In general, regions will export electricity when regional demand is being met and the price of electricity in the exporting region is sufficiently low to displace production in the importing region. Correspondingly, they will import electricity when regional demand is not being met and the price is sufficiently high for exporting regions to displace production in the importing region. A negative coefficient is hypothesized when spot prices are regressed against *FLOW*, though this effect will vary by region as some have more and larger regional interconnectors than others.

The second of these additional variables is the difference between the daily available generation capacity and actual generation. This produces the daily slack (*SLK* in 100 MW) available for generators. We expect that larger levels of slack are associated with lower prices given the willingness of generators to attempt to undercut other generators in order to include production in the dispatch schedule. The final group of explanatory variables represents weekly demand and seasonal factors, comprising dummy variables indicating the day-of-the-week and month-of-the-year. Given we are primarily concerned with the impact of generation mix on prices, notwithstanding the abundant evidence already of day-of-the-week and month-

of-the-year effects in Australian wholesale prices in Higgs and Worthington (2005), we provide no detailed discussion of the hypothesized signs for these many variables, which we mainly include as controls.

A number of ways are possible to incorporate the structure of pooled data in estimating supply equations for the wholesale electricity markets. In this study, we incorporate the regional effects in a fixed effects model by incorporating regional interaction terms with all explanatory variables and estimate a pooled interaction regression model and a quantile pooled interaction regression model

3. Results

The results in Table 2 provide the estimated coefficients, standard errors and p-values of the null hypothesis that the parameters individually are equal to zero. Columns 3 to 5 present the estimated results of the pooled interaction model while columns 6 to 8, 9 to 11, 12 to 14, 15 to 17, and 18 to 20 present the results for the quantile regression model for values of $\tau = 0.05, 0.25, 0.50$ (median), 0.75 and 0.95 . Also included in Table 2 are statistics for the R^2 (OLS) and pseudo R^2 (quantile).

<INSERT TABLE 2 HERE>

The model first discussed is the pooled interaction regression. Sixty percent of the estimated coefficients are significant at least at the 10 percent level of significance. Using the F-statistic (31.1080) and p-value (<0.0010), the null hypothesis that all slope coefficients are jointly zero is rejected at the 1 percent level. The short-run price elasticities of supply/demand at the means for NSW, QLD, SA, TAS and VIC are respectively 0.195, 0.253, 0.120, 0.911 and 0.153 (inelastic) indicating, for example, that in NSW a 10 percent

increase in the wholesale spot price of electricity is associated with a 1.95 percent increase in the quantity of electricity supplied in the short-run.

The long-run price elasticities at the means for NSW, QLD, SA, TAS and VIC are respectively 0.265, 0.409, 0.131, 1.595 and 0.166. The long-run price elasticity of 0.265 indicates a ten per cent increase in wholesale price is associated with a 2.65 percent increase in quantity supplied in NSW suggesting that the supply elasticity is significantly more elastic in the long run. Similar elasticities are obtained for the other regional markets with the exception of TAS. In general, supply is usually more elastic in the long run than the short run as it is generally assumed that in the long-run more factors of production, such as additional/new plants, can be utilized to increase supply. In TAS, the short-run price elasticity of supply of 0.911 (inelastic) and the long-run price of 1.595 (elastic) are more pronounced than in the other regional markets. This is because TAS has predominantly hydroelectricity generation where additional water can be released to easily increase supply.

The positive FLOW coefficient (0.112) for SA suggests that on average the spot price increases by \$11.20/MWh with the increase of electricity flow into SA. The negative FLOW coefficients for NSW (−0.074), QLD (−0.001), TAS (−0.075) and VIC (−0.017) suggest that the interconnector across the NEM, spot prices will fall by \$7.40/MWh for NSW, 10 cents/MWh for QLD, \$7.50/MWh for TAS and \$1.70/MWh for VIC. The SLK variable represents the difference between the daily available generation capacity generation and daily actual generation. All estimated SLK coefficients are negative which indicate that as the daily available capacity increases the spot price will decrease. The SLK variable has the largest impact on SA with a MW increase in SLK, the spot price will decrease by \$24.40 and the smallest impact is on TAS with an increase in SLK will reduce the spot price by \$1.50.

In terms of the day-of-the-week and month-of-the-year effects (results not shown), relative to Sunday, electricity prices are lower from Monday to Friday across all regions

(excluding TAS) and electricity prices are dearest on Saturday. For TAS, electricity prices are dearest from Monday to Friday and cheapest on Saturday as compared to Sunday. The spot price is lowest on Tuesday in NSW and QLD, on Friday in SA, Wednesday in VIC and on Saturday in TAS. Generally (and relative to January), spot prices are higher in the February, March and April and lower in September, October and November.

As a comparison, Solibakke (2002), for example, found that price volatility in the Nordic spot electricity market increased strongly on Mondays and Saturdays and was especially strong during May, June and July. Herbert (2002: 34) also presented evidence that "...there is seasonality in (electricity) price risk. Not surprisingly, price risk increases in the summer...power prices also increase in the winter". And Hadsell et al. (2004) found that volatility behaviour differed by month across five US electricity markets. Higgs and Worthington (2005) found that volatility in Queensland and South Australia was highest on Monday, falling progressively through the week. In NSW, however, volatility increased during the week and fell over the weekend. Volatility was lowest on Wednesday in SA, on Friday in QLD and VIC and on Saturday in NSW.

In relation to generation mix, the cheapest electricity is produced by BNCL, BKCL and CCGT while the most expensive is OCGT, HYDR and WIND. For BNCL, a one percent increase in generation will reduce the spot price by \$2.64 for SA and \$1.71 for VIC. A one percent increase in BKCL generation will reduce the spot price by \$1.50 for NSW and \$1.15 for QLD. Electricity generated by CCGT has the greatest impact on NSW, SA and VIC with the reduction in spot price of \$3.82, \$2.73 and \$1.89 respectively. Generation by OCGT will increase spot prices by \$20.05 for NSW, \$8.18 for VIC, \$5.66 for TAS, \$5.02 for SA and \$3.42 for QLD. It would then be more effective (in terms of minimizing the change to the wholesale price) to use CCGT rather than OCGT as peaking plants. The renewable generation HYDR is cheapest for TAS and its connected regional market, VIC, with a one

percent increase in its generation reduces electricity prices by 19 cents and 18 cents respectively. A one percent increase in HYDR generation, electricity prices will increase spot prices by \$12.35 in QLD and \$3.83 in NSW. As for NSW, it is more cost effective to use HYDR than OCGT. A one percent increase in WIND generators tend to reduce the spot prices by \$1.48 for SA and \$1.14 for TAS but increase the spot prices by \$2.88 for NSW and \$0.52 for VIC.

The final part of the empirical results examines the impact of quantile regressions on the estimated coefficients. The results of the quantile regression at the 5th, 25th, 50th 75th and 95th are shown in Table 2. According to goodness of fit, the adjusted R^2 s for the 50th, 75th and 95th quantile regressions are larger than the pooled interaction regression model. As for the quantile regression coefficients, casual inspection suggests a pattern roughly in line with the whole sample result, with the possible emergence of stable estimates for the lagged price, contemporaneous demand, slack, flow, day-of-week and month-of-year dummies.

The disparity between spot electricity price and generation mix is more evident, particularly at the right tail of the distribution. Brown coal is generally the cheapest generation mix. The pooled interaction regression model suggests that a one percent increase in BNCL generation in SA and VIC is associated with a reduction in spot price (per MWh) respectively of \$2.64 and \$1.71. Results for the 75th and 95th percentile regressions suggest a one percent increase in BNCL leads to a reduction in the spot price of 18 cents and \$1.01 for SA and 10 cents and 47 cents for VIC respectively. As for the lower quantiles of 5th and 25th the spot prices increase by 11 cents and 5 cents for SA and 2 cents and 16 cents for VIC respectively. This indicates that the pooled interaction model overestimates the negative impact of BNCL as compared to the quantile regressions. Similar results are obtained for BKCL generation in NSW and QLD.

The most expensive generation mix is OCGT where a one-percent increase in generation produces increases in spot price of \$20.05 for NSW, \$8.18 for VIC, \$5.66 for TAS, \$5.02 for SA and \$3.42 for QLD according to the pooled interaction model. For NSW, increases in spot price for a one-percent increase in OCGT production range from 45 cents (5th quantile) to \$1.67 (75th quantile). These are much lower than the pooled interaction model of \$20.05, while the top 95th percentile regression produces a larger increase of \$19.08 in spot price. Similar results are obtained for QLD. In TAS, the quantile regression suggests spot price increases for a one-percent increase in OCGT production range from 57 cents (25th quantile) to \$1.72 (75th quantile) which are lower than \$5.66 for the interaction model but the spot price spikes to \$29.82 in the 95th quantile. Similar results are obtained for VIC where the spot price increases to \$21.59 in the 95th quantile as compare to the \$8.18 in the pooled regression model. These results suggest that the spot prices can be more volatile in the higher quantiles. As for SA, one percent generation in OCGT reduces the spot price at the 5th by 8 cents while at the 25th, 50th, 75th and 95th quantiles increase the spot price by 1 cent, 24 cents, 91 cents and \$8.31 respectively. The pooled interaction estimates for CCGT suggest reductions in spot price for a one percent increase in generation for each region. This is contrary to the quantile regression estimates with increases in spot price in the 5th, 25th and 50th quantiles. The savings are only realised in the 95th quantile in all regions with the exception of TAS.

According to the pooled interaction model, a one-percent increase in HYDR generation leads to increases in spot prices for NSW (\$3.83) and QLD (\$12.35) but decreases for TAS (20 cents) and VIC (18 cents). The spot price for HYDR generation in NSW is lower for all quantiles with the exception of the 95th quantile ranging from a reduction of 4 cents (5th quantile) to an increase of spot price to 95 cents (50th quantile) and with a higher increase in spot price of \$2.74 in the 95th quantile. As for QLD, a one-percent increase in HYDR is

associated with similar spot price increases across all quantiles ranging from \$1.58 (75th quantile) to \$5.27 (95th quantile). This is much lower than \$12.35 for the pooled interaction model.

In TAS with the highest HYDR generation, it is expected the spot price will decrease as generation increases. The quantile regression results show that in the lower quantiles the spot prices increase. As for the 5th, 25th and median quantiles regressions, a one percentage increase in HYDR generation leads to an increase in the spot price of 20 cents, 14 cents and one cent respectively, while the 75th and 95th quantile HYDR generation reduces the spot price by 5 cents and one cent respectively. The pooled model suggests that as generation in HYDR increase in VIC the spot price falls by 18 cents. The contrary is evident across all quantile regressions with spot prices increasing from 15 cents (5th quantile) to 41 cents (25th quantile).

Generation by WIND indicates that the spot price increases for NSW (\$2.88) and VIC (52 cents) and decreases for SA (\$1.48) and TAS (\$1.14) from the pooled interaction results. For WIND generation, the NSW spot prices increase across all quantiles ranging from 13 cents (75th quantile) to \$1.63 (95th quantile). The VIC spot price increase from WIND generation according to the pooled regression is not evident across the quantiles. The VIC spot prices decrease from \$0.19 in the 95th quantile to \$0.81 in the 5th quantile. As for SA, WIND generation reduces spot prices in all quantiles ranging from \$0.01 in the 25th and 50th percentile to \$0.58 in the 95th quantile. The TAS spot prices decrease with WIND generation by about \$0.25 across all quantiles and with a higher fall in spot price of \$0.42 in the 95th quantile.

The quantile regressions demonstrate that the increases/decreases in spot prices are not as pronounced in the lower quantiles but in the 95th quantile or the spike/abnormal spot prices some of these changes are amplified. Overall the pooled interaction model tends to

overestimate the estimated coefficients for generation mix as compared to the quantile regressions. And in general, it is cheapest (in terms of minimizing the change to the wholesale price) to use BNCL and BKCL, then OCGT WIND, and HYDR and finally CCGT across all OLS and quantile regressions and all regional markets.

4. Conclusion

As expected generation mix exerts a strong influence on electricity prices, with prices being generally lower with the use of brown and black coal and higher with the use of gas and renewable technologies, all of which have lower GHG emissions. This suggests the likelihood of higher wholesale prices as the electricity industry moves toward renewable energy targets in developing low-emission technologies such as gas and wind power. There are also indications that the price effects of increasing the share of renewables is ‘cheaper’ in some regions than others, with wind capacity suggestively best developed in SA and TAS and hydro in VIC and TAS. In other results, flow across the regional interconnectors generally reduces regional prices as does slack generation capacity.

Of course, this analysis ignores any allowance for the recently introduced system of carbon taxation intended to reflect the contribution of both black and brown coal to GHG emissions. The expectation is that this will ultimately add to wholesale prices derived from these sources of generation, with estimates of a 10 percent increase in wholesale prices overall. Likewise, there is no allowance for the longer-term changes in generation technology. For example, there is the argument that with the widespread shift to CCGT because of its relatively lower GHG emissions, there will be a significant reduction in the cost per kilowatt of generation, for example, through ‘learning by doing’ and the exploitation of scale economies (Naughton 2000). Finally, natural gas production in Australia is currently centered on conventional sources, and gas is largely produced from the offshore Carnarvon

Basin in WA, the Cooper/Eromanga basin in SA and QLD, and VIC, together accounting for 96 percent of Australia's conventional natural gas production. This is well-reflected in the share of gas in electricity generation in South Australia (WA is not part of the NEM and therefore not included in this analysis).

However, very recently, coal seam gas (CSG) production has increased rapidly, with Australia's annual CSG production increasing from just 1 petajoule (PJ) in 1996 to 240 PJ in 2010–11, now accounting for about 10 per cent of Australia's total gas production. Of this, Queensland and New South Wales are the main sources, with Queensland producing 234 PJ (or 97 per cent) from the Bowen (121 PJ) and Surat (113 PJ) basins and CSG accounting for about 17 percent of natural gas-based electricity generation. In New South Wales, about 6 PJ was produced from the Sydney Basin. Nonetheless, exploration in Queensland continues apace in the Bowen, Galilee and Surat basins while in New South Wales exploration continues in the Sydney, Gunnedah, Gloucester and Clarence–Moreton basins. One result should be a dramatic increase in the share of generation by natural gas (including CSG), particularly in regions like QLD and NSW where it has been conventionally less important, and this likewise has the potential to affect the longer-term applicability of our results.

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