# Have Competitive Electricity Markets Rewarded Flexible Gas-powered Generation? Australia's Lessons for ASEAN

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**Abstract**

A competitive electricity market, which allows high prices to reflect generation shortage, is often assumed to be a beneficiary factor for gas-powered generation (GPG). However, the actual impact of a competitive electricity market on gas generation is yet to be examined. Using Australian daily gas and electricity data, this paper investigates whether the country's competitive electricity markets have promoted GPG development. Considering the significant renewable energy penetration and increasing GPG in Australia and its highly transparent competitive electricity market, the Australian case offers future scenarios faced by developing countries. The empirical tests fully support the hypothesis; namely, the GPG is negatively related to generation from variable renewable energies and positively associated with the electricity demand gap and electricity price. The findings suggest that ASEAN should boost gas use and continue electricity market liberalisation and regional electricity market integration.

*JEL Classification Q41; C32*

*Keywords: Electricity market; renewable; gas power; Australia*

## 1 Introduction

A competitive electricity market, which allows high prices to reflect generation shortage, is often a beneficiary factor for gas-powered generation (GPG) (Devlin et al., 2017). However, the actual impact of a competitive electricity market on gas generation is yet to be examined. Natural gas is widely considered a transitional fuel during the energy transition process due to its flexibility in power generation that can mitigate volatility from variable renewable energies (VREs). Due to the relatively high costs of gas to coal, GPG is not competitive with coal-fired generation in a competitive market, except in the United States, where gas prices are low due to the shale gas revolution. However, GPG could be a cost-competitive solution to avoid the high system integration costs of a large share of VREs (Atwa and El-Saadany, 2010). In the case of higher-than-usual demand for electricity or low generation from the VREs, GPG will step in to fill the gap, which earns its reputation as a peak demand generator. For this flexible role, when gird scale storage is not available, the availability of GPG capacity will determine the penetration of VREs. However, due to its intermittent use induced by low generation from the VREs, a gas power generator needs high prices to be economically feasible. A competitive electricity market based on merit-order in dispatch could accelerate the development of VREs in theory. However, the role of the electricity market in facilitating VREs is certain as real-world evidence is mixed. For example, GPG was crowded out of the German generation mix (Hörnlein, 2019).

Understanding the relationship between GPG and VREs is important as the rising VREs' share worldwide prompts the question of who will provide the backup to offset the variability of VREs. While the development of storage technologies is the ultimate solution, GPG is considered an immediate and transitional solution. Much of the literature finds a functional gas market will provide the price signals for GPG. However, the relationship between GPG and VREs is complicated in that VREs could reduce gas generation.

The Australian case provides an interesting example to investigate the role of the electricity market on the development of flexible generation capacity needed to mitigate VREs. The Australian national electricity market (NEM), which commenced operation as a wholesale spot market for electricity in December 1998, is one of the most successful electricity markets in the world. However, while the VREs increased dramatically in capacity and generation, GPG is stable, and the capacity even declined between 2014 and 2020. Furthermore, two more GPG plants were being closed before 2022, and the future of the rest of the GPG plants is uncertain (Australian Energy Regulator, 2021). The Morrison government proposed a gas-fired recovery to boost economic growth during the COVID-19 pandemic (Australian Government, 2020). The policy assumes that Australia has abundant gas reserves, so GPG is affordable and can function as a critical enabler of the economy. However, the first project under this plan has invited many objections to the government investing in new gas *(The Guardian*, 2021). The Australian pioneer experience can inform latecomers in electricity market development, including Southeast Asian nations.

Considering the significant renewable energy penetration and increasing GPG in Australia and its highly transparent competitive electricity market in terms of historical prices and generating plant dispatch, with Australian daily gas and electricity data, this paper investigates (i) whether GPG is negatively related to the generation from VREs, (ii) whether GPG and gas prices are positively related to electricity demand gap and electricity prices, and (iii) whether gas prices have mixed relationships with GPG.

The main contribution of this chapter is threefold. Firstly, this chapter presents empirical studies on the relationship between electricity and natural gas markets in Australian NEM with daily data. Secondly, it presents an econometric analysis of the impact of renewable energy generation on GPG through actual generation instead of generation capacity. Thirdly, this chapter statistically tests the interplay between the gas and the electricity markets from multiple perspectives by using various time-series models and available daily data in different locations of Australia, considering the season effect, region effect, and endogenous effect, which provides convincing evidence to support this chapter's conclusion.

The paper proceeds as follows. After the introduction, section 2 discusses the Australian NEM and the development of VREs and GPG. There researchers' hypotheses are proposed based on NEM and literature review. Section 3 reports the data and methodology. The empirical results are presented in section 4, followed by implications for ASEAN and other latecomers in the electricity market. The last section concludes the paper.

# 2 Background and Research Hypotheses

## 2.1 The Australian national electricity market (NEM) in transition

NEM started operation in December 1998 and spans Australia's eastern and south-eastern coasts, including six interconnected states and territories and five price regions: New South Wales (NSW) (including the Australian Capital Territory), Queensland, Victoria, South Australia, and Tasmania.[1] NEM is one of the world's largest interconnected electricity systems, having around 40,000 kilometres of transmission lines and cables, delivering around 80% of Australia's electricity consumption and supplying 10.2 million customers (DISER, 2021). Around 30 retailers and over 100 generation companies are in the NEM wholesale market. There are also eight frequency control ancillary services spot market prices, with electricity production and frequency control services co-optimised across five imperfectly interconnected states or regions.

**Table 9.1: National Electricity Market, January 2021**

| | |
|---|---|
| Participating jurisdictions | OLD, NSW, VIC, SA, TAS, ACT |
| NEM regions | OLD, NSW, VIC, SA, TAS, |
| NEM installed capacity (including rooftop solar) | 67,046 MW |
| Number of large generating units | 295 |
| Number of customers | 10.2 million |
| NEM turnover 2020 | $10.9 billion |
| Total electricity consumption 2020 | 190.1 TWh |
| National maximum demand 2020 | 35,043 MW |

Source: Australian Energy Regulator (2021) .

NEM is a wholesale market that facilitates exchange between electricity producers and electricity consumers through an electricity pool, a set of procedures that the Australian Energy Market Operator (AEMO) manages according to laws, regulations, and rules rather than a physical location. NEM is made possible by sophisticated information technology systems that balance supply with demand, maintain reserve requirements, determine dispatch and the spot price, and facilitate the financial settlement of the physical market (AEMO, 2010).

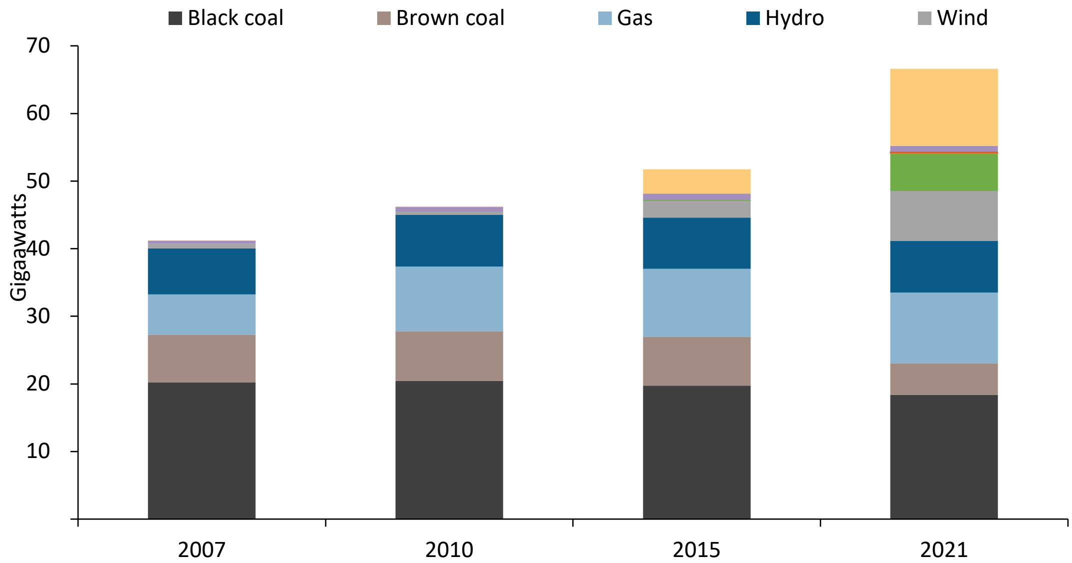
NEM has a transparent and balanced regulatory framework, including various key institutions (DISER, 2021). The Australian Energy Market Commission develops market operation rules, and the Australian Energy Regulator (AER) enforces the rules and judgements on the regulatory proposals of monopoly network operators. AEMO handles day-to-day operations of the electricity and gas markets. The Energy Security Board (ESB) monitors NEM's system performance, risks, improvement opportunities, and affordability to safeguard NEM's health. The ESB also coordinates the implementation of the reform blueprint produced by Australia's chief scientist. The Australian Competition and Consumer Commission informs the Australian government on long-term energy policies that may be changed due to changes in electricity generation, emerging technologies, such as solar batteries and shifting consumer preferences. The policies will further promote NEM's modernisation.

[1] Due to the distance between networks, Western Australia and the Northern Territory are not connected to NEM. They have their own electricity systems and separate regulatory arrangements.

## 2.2 Energy transition in Australia's electricity generation

Energy transition has progressed well in Australia's electricity market, summarised from two aspects: capacity and electricity generation by fuel type. Figure 9.1 shows that the generation capacity for black and brown coal has declined in the past 2 decades, accounting for 66.2% in 2007 and 34.6% in 2021. Meanwhile, wind and solar generation capacity has dramatically increased after 2015. Notably, solar photovoltaic (PV) (including solar farms and rooftop solar) was the second-largest generation technology in Australia in 2021. The total VREs generation capacity is the largest amongst all fuels, 36.9%.

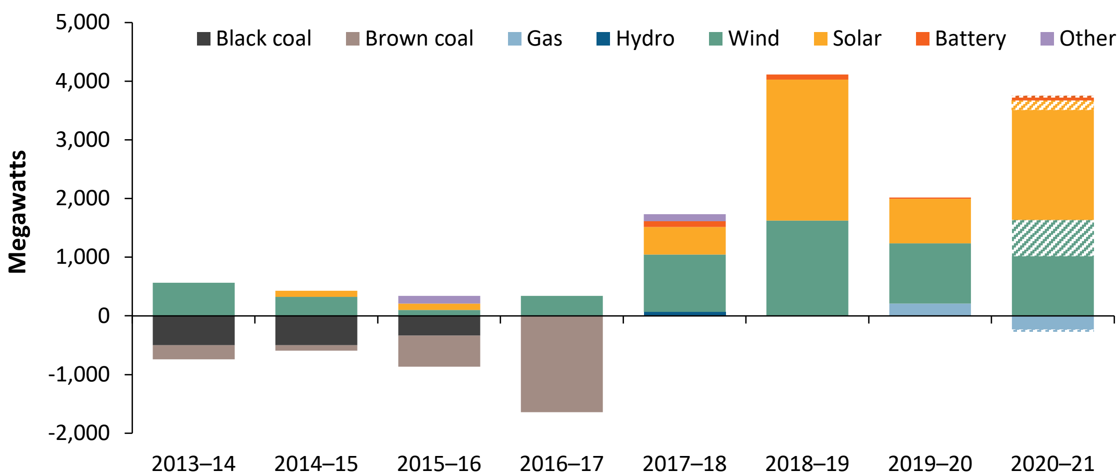
**Figure 9.1: Generation Capacity by Generation Technology**




Source: Australian Energy Regulator (2021).

Moreover, a close examination of the change in generation capacity can better demonstrate the transition in the power generation sector. According to Figure 9.2, there has been no new investment in coal-fired generation in Australia since 2012, and almost 4 gigawatts (GW) of coal-fired generation has left the market since 2012. On the contrary, around 12.5 GW of large-scale wind and solar capacity and 8.5 GW of rooftop solar PV began operating over this same period and significantly increased dramatically from 2017.

**Figure 9.2: Entry and Exit of Generation Capacity in NEM by Generation Technology**

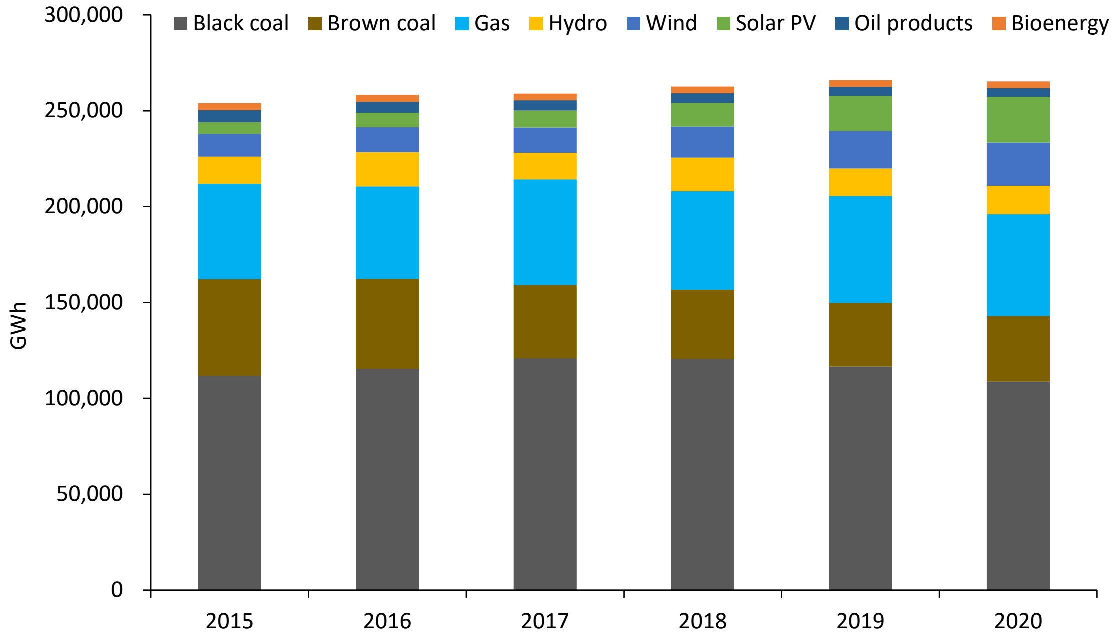


Note: Capacity includes scheduled and semi-scheduled generation but not non-scheduled or rooftop PV capacity. 2020–2021 data are as of 31 March 2021. Investment and closures expected between 1 April and 30 June 2021 are shown as shaded components.

Source: Australian Energy Regulator (2021).

Regarding electricity generation by fuel type in Australia, the proportion of generation from coal declined from 63.9% in 2015 to 53.9% in 2020. Meanwhile, the proportion of generation from VREs increased from 14.1% to 24.4%. Notably, solar power grew by 30.3% in 2020 and overtook wind to be the largest contributor to VREs, with a 36.9% share of renewable generation and 9.5% of total electricity generation in Australia (Figure 9.3).

**Figure 9.3: Australian Electricity Generation by Fuel Type**




Source: Department of Industry Innovation and Science (2021).

As for the generation output by fuel source in NEM, the proportion of generation output from VREs has reached 27.3%, of which the proportion of wind generation output is 13.9% (Table 9.2).

**Table 9.2: Generation in NEM by Fuel Source (as of 30 September 2021)**

| Fuel | NEM Capacity (% of total generation) | NEM Output (% of total generation) |
|---|---|---|
| Black coal | 32.0 | 49.2 |
| Brown coal | 8.4 | 16.7 |
| Gas | 17.1 | 6.4 |
| Hydro | 14.6 | 9.3 |
| Wind | 14.7 | 13.9 |
| Liquid | 1.3 | 0.1 |
| Grid solar | 9.9 | 3.9 |
| Battery | 0.6 | 0.1 |
| Other | 1.4 | 0.4 |

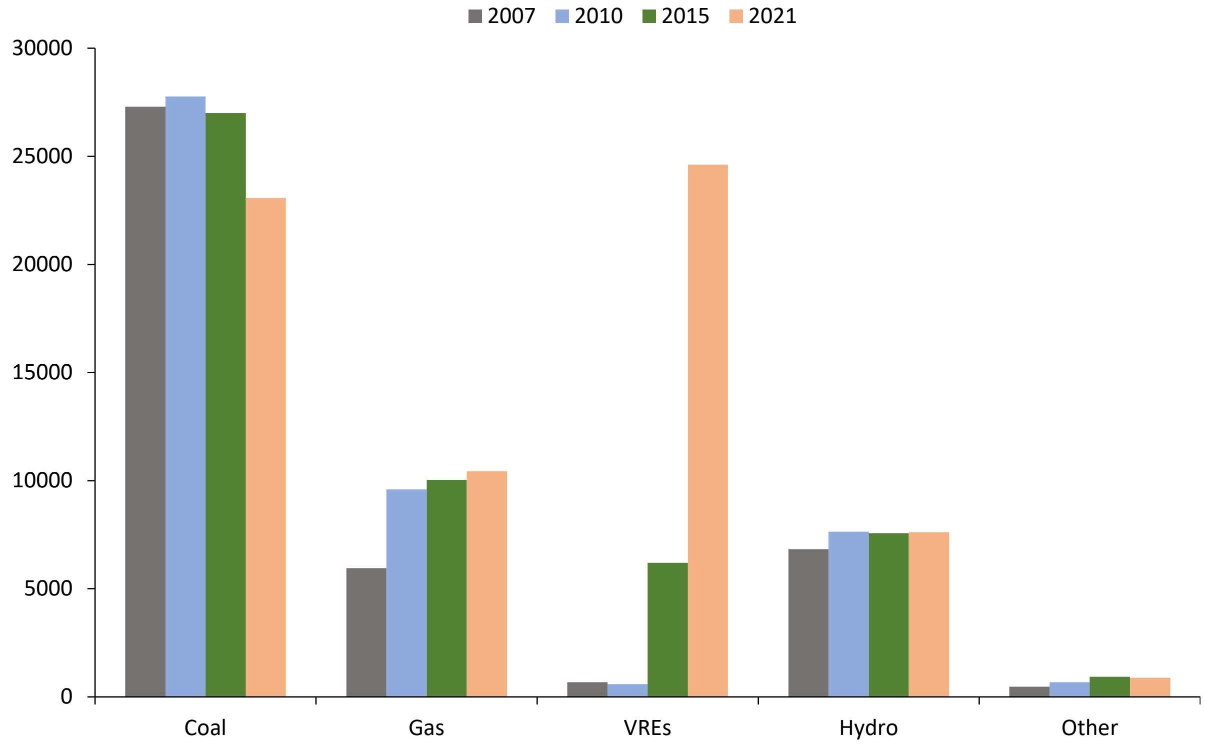
Source: Australian Energy Regulator (2021).

## 2.3 Development of GPG and VREs

GPGs typically operate as 'flexible' or 'peaking' plants in Australia because gas is a relatively expensive fuel for electricity generation. Gas generation will be operated when electricity demand and prices are highest; it also tends to be seasonal. Furthermore, it is strongly affected by the increasing renewable generation and withdrawal of coal-fired generators.

GPG plays an increasingly crucial role in managing the variability of output of weather-dependent renewable generations. However, GPG capacity has not been developed along with the VREs. While VRE generation capacity increased from 674 MW in 2007 to 24,614 MW in 2021, GPG capacity only increased from 5,946 MW to 10,436 MW at the same time. Moreover, GPG capacity declined between 2014 and 2021 (Figure 9.4), despite a small new investment in gas generation in 2019. Two GPG plants were also scheduled to retire in 2020–2022. The future of other plants is speculated to be in danger, too (AER, 2020).

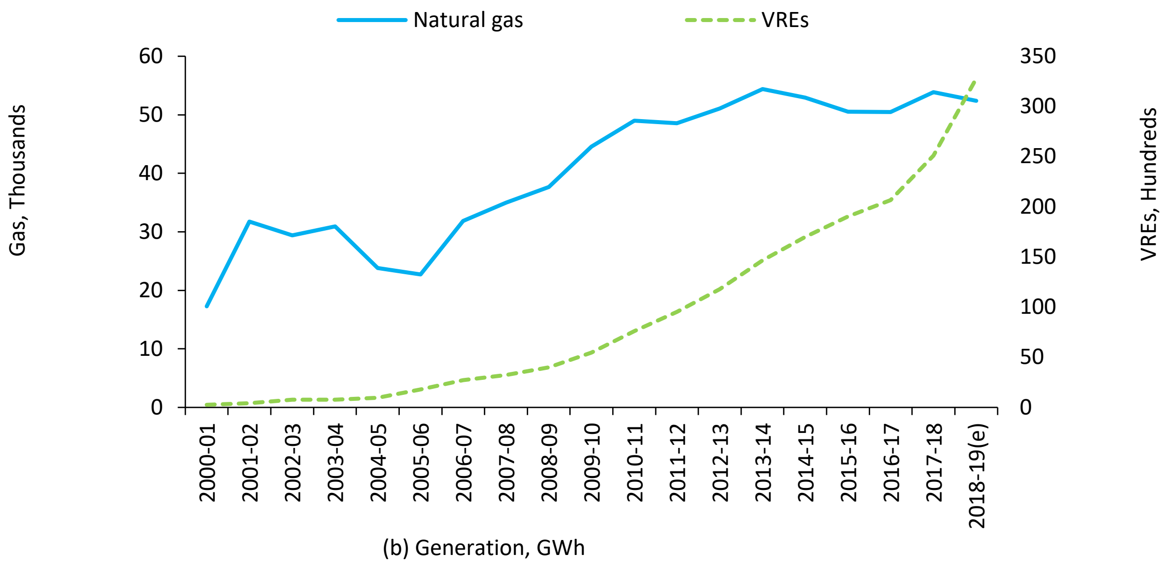
**Figure 9.4: Generation Capacity by Technology (MW)**




Source: Australian Energy Regulator (2021).

GPG is also not in parallel with VRE development. For example, while VRE generation increased 126-fold from 260 GWh in 2000–2001 to 32,778.8 GWh in 2018–2019, GPG only increased threefold from 17,271 GWh to 52,387 GWh in the same period. Particularly, when VRE generation increased 430% in 2010–2019, the GPG only increased 7% (Figure 9.5).

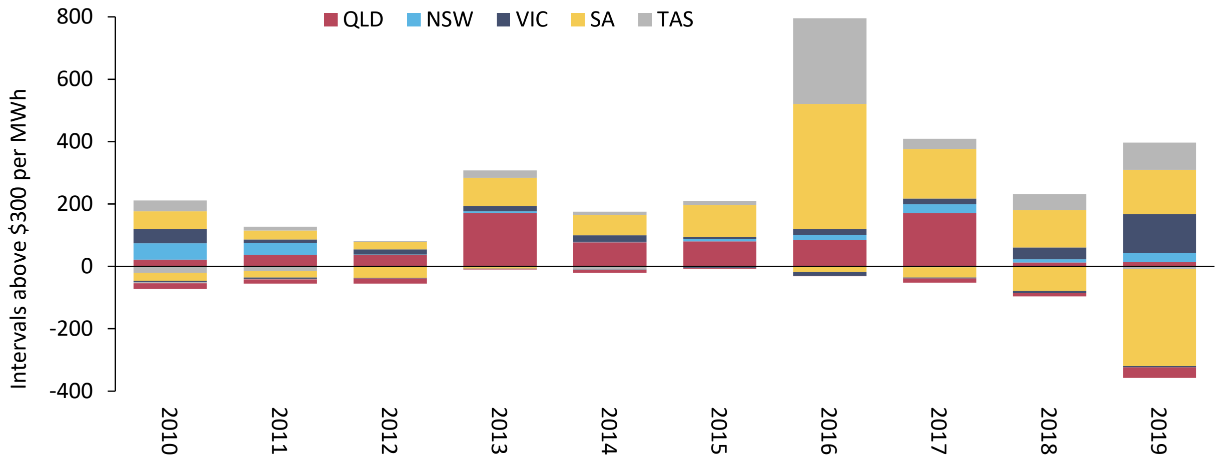
**Figure 9.5: Generation in the Australian National Electricity Market**




Sources: Department of Industry Innovation and Science (2021).

The lack of parallel development between GPG and VREs could be due to a low frequency of high electricity prices and a high frequency of high gas prices. Due to the large share of renewables in the generation mix, the capability of coal and gas plants to set high dispatch prices declines (AER, 2021). The number of intervals when the spot electricity price is above $300 per MWh in NEM (Figure 9.6) may impair the profitability of gas plants that often rely on selling cap contracts to customers that wish to insure against high prices. This low frequency of high electricity prices is in contrast with the significantly increased gas prices from 2015 to 2018, when Queensland's liquefied natural gas (LNG) plants purchased gas supplies from the domestic market to meet export obligations (Grafton et al., 2018). Gas prices were volatile in 2017 due to the LNG export and large brown coal plant closures (Hazelwood and Northern). These events resulted in high electricity prices across NEM despite electricity demand remaining flat. Higher fuel costs further worsened the economic viability of the GPG during this period. Recent dramatic falls in NEM electricity prices followed the domestic gas market, which has followed the world LNG markets. Given that the NEM market structure and demand have not changed much since 2017, it is hard to see how the level of generation competition can be suggested as having any material impact on electricity price outcomes – either high or low.

**Figure 9.6: Prices Above $300 per MWh and Below – $100 per MWh (Number of Intervals)**



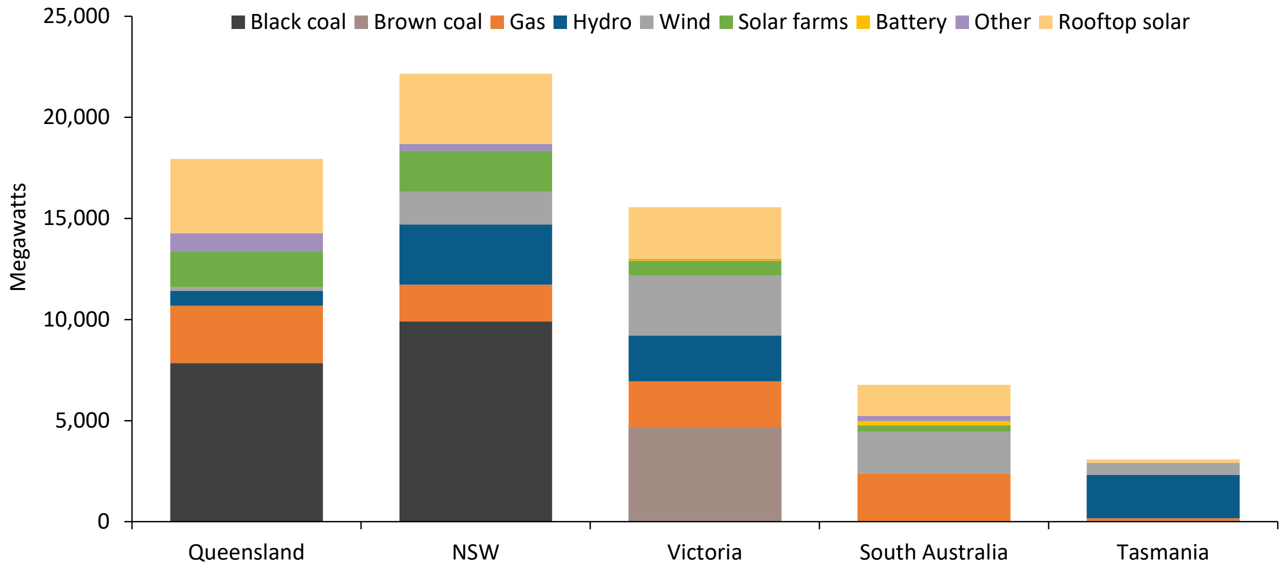

NSW = New South Wales, QLD = Queensland, SA = South Africa, TAS = Tasmania, VIC = Victoria.

Source: Australian Energy Regulator (2021).

## 2.4 Regional generation mix

The generation mix has significant heterogeneity across the states or territories in NEM. From the regional distribution of the generation capacity, coal is the dominant generation source in NSW and Queensland, while gas and VREs dominate South Australia, and hydroelectricity dominates Tasmania (Figure 9.7). Moreover, wind generation capacity in Australia's NEM is located mainly in Victoria, South Australia, and NSW. Solar generation capacity is situated primarily in NSW and Queensland. Meanwhile, GPG capacity is located mainly in Queensland, South Australia, Victoria, and NSW. Each of these regions also has short-term gas trading hubs. Australian domestic wholesale gas price market hubs are found in Adelaide, Sydney, Brisbane, and Victoria's Declared Wholesale Gas Market (DWGM) (Grafton et al., 2018).

**Figure 9.8: Generation Capacity in the National Electricity Market by Region and Fuel Course in 2020**

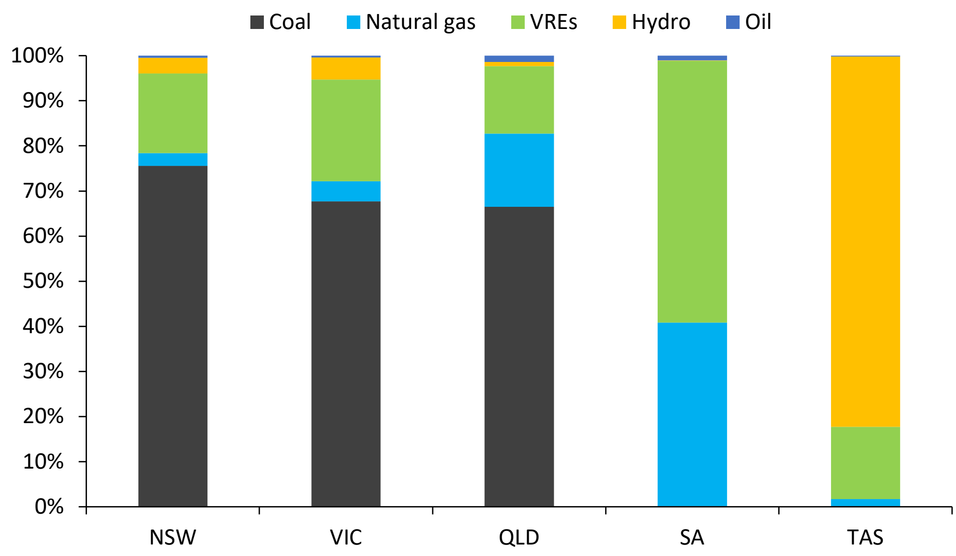



Note: Generation capacity on 1 January 2021. Other dispatch includes biomass, waste gas, and liquid fuels.

Source: Australian Energy Regulator (2021).

As for the electricity generation in 2020, coal was still the dominant generation source in NSW, Victoria, and Queensland, while VREs and hydrogen dominate South Australia and Tasmania (Figure 9.8). In terms of emissions, South Australia and Tasmania have done well.

**Figure 9.8: Australian Electricity Generation Mix by State, 2020**

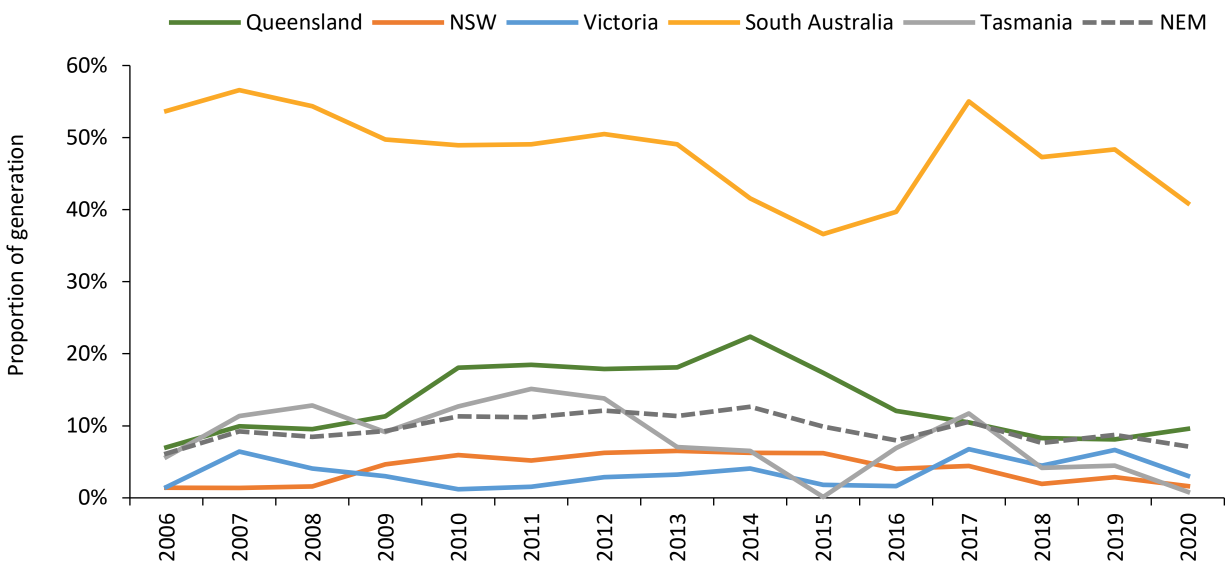



Source: Department of Industry Innovation and Science (2021).

The proportion of GPG in South Australia is still the largest, at 56.6% and 55.0% in 2007 and 2017, respectively. That declined to 40.9% in 2020, causing VRE generation to increase sharply (Figures 9.9 and 9.10). On the other hand, the proportion of GPG in Queensland climbed to 22.4% in 2014, then decreased to 9.6% in 2020. The proportion is not high in other regions, but it has been decreasing in recent years.

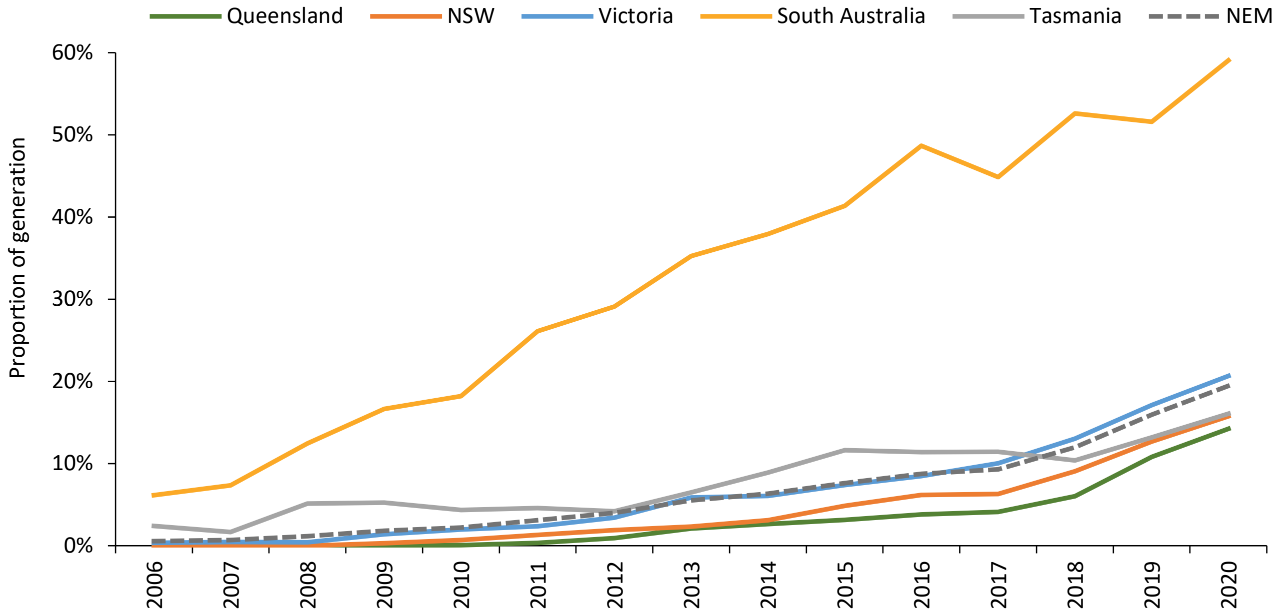
Moreover, each state in Australia will further increase VRE investment (Figure 9.11). For example, Queensland and NSW will invest more in solar generation. NSW, Victoria, and South Australia will invest more in wind generation, while the GPG investments of states are very small.

**Figure 9.9: The Proportion of Gas-powered Generation**



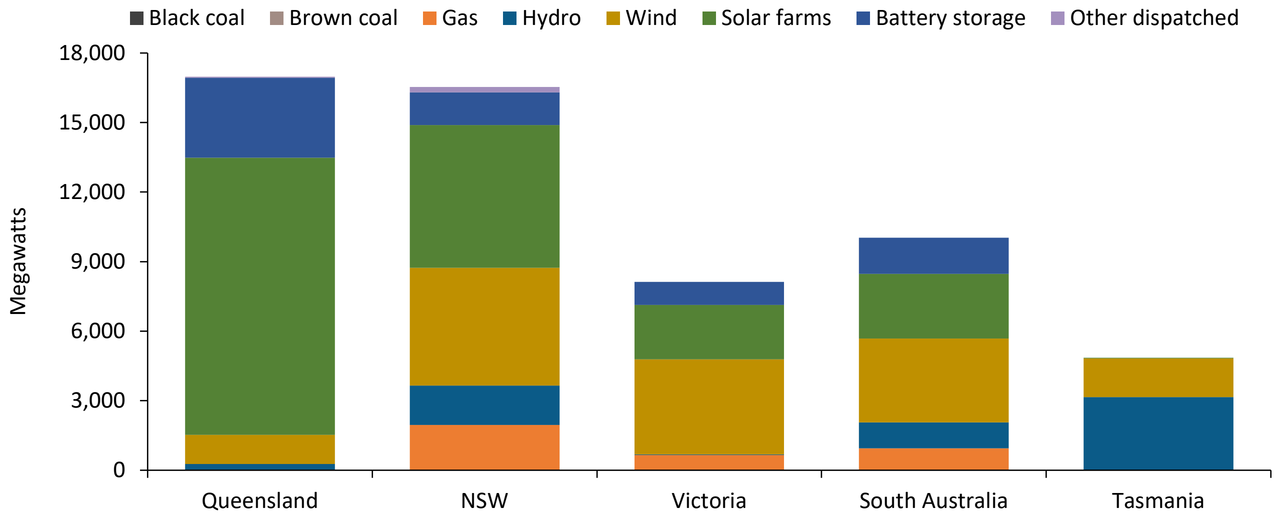
Source: Australian Energy Regulator (2021).

**Figure 9.10: The Proportion of VRE Generation**




Source: Australian Energy Regulator (2021).

**Figure 9.11: Announced Generation Proposals, January 2021**



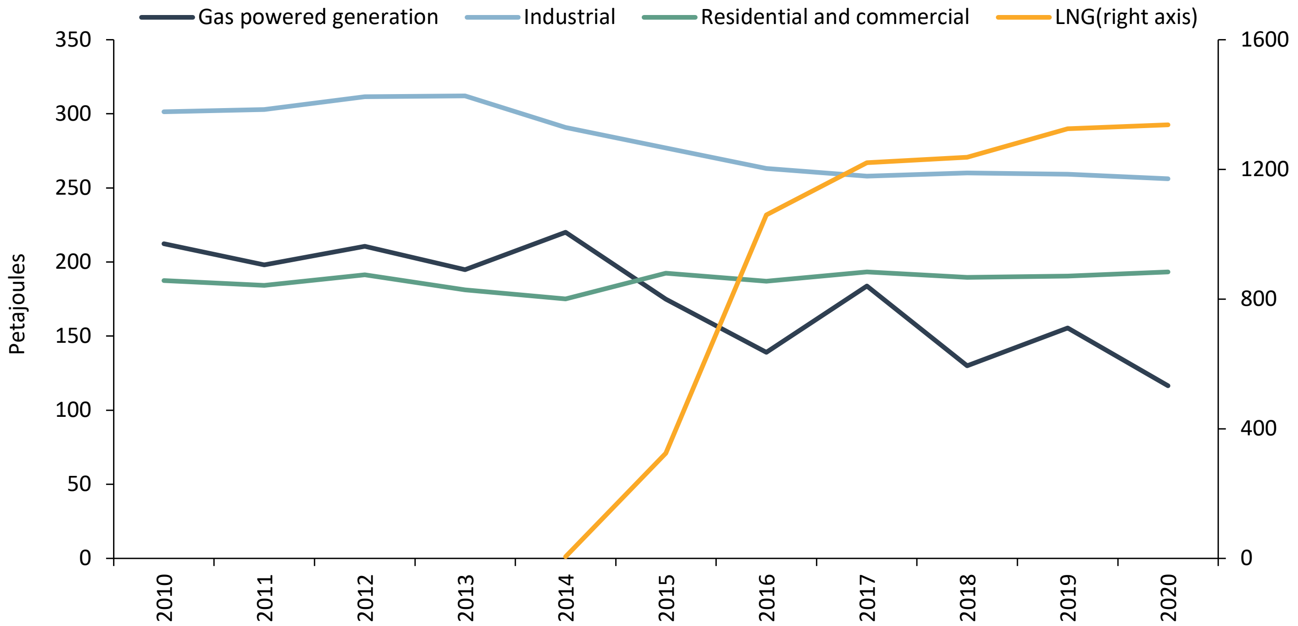

Source: Australian Energy Regulator (2021).

## 2.5 Gas demand

The gas demand for GPG was above 220 petajoules (PJ) before 2014 and then declined to 116 PJ in 2020 with the increase of VREs (Figure 9.12).

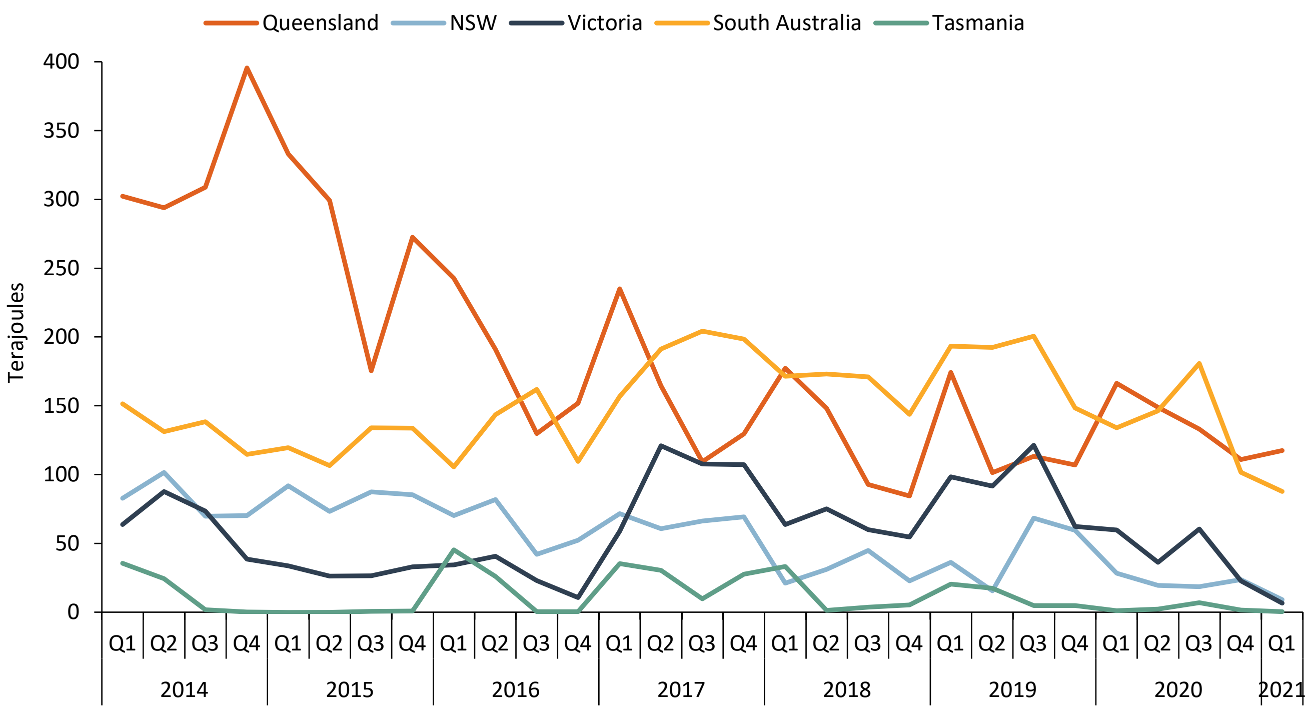
As for each region, the gas demand for GPG shows obvious seasonal fluctuations. For example, there was a significant decline from 2014 in Queensland and from 2017 in other regions (Figure 9.13).

**Figure 9.12: Eastern Australian Gas Demand**




Source: AEMO (2021).

**Figure 9.13: Quarterly Gas Demand for Gas-powered Generation (Average Tj/ day)**



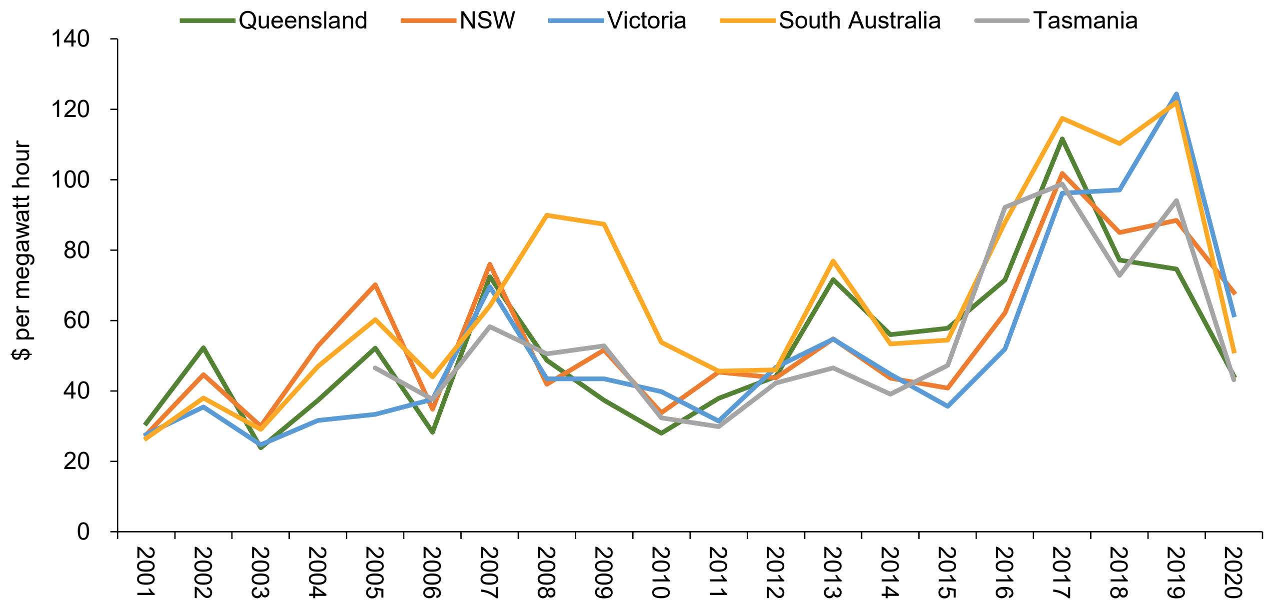

Source: Australian Energy Regulator (2021).

## 2.6 The electricity and gas price

The trend of electricity prices in various regions is very similar, showing obvious fluctuations and an upward trend (Figure 9.14). The peaks appear in 2002, 2005, 2007 (2008 in Victoria), 2014, and

2017. The electricity prices of Victoria and South Australia reached the highest in 2019 in this period, but the electricity prices in each region dropped sharply in 2020.

**Figure 9.14: Wholesale Electricity Prices**

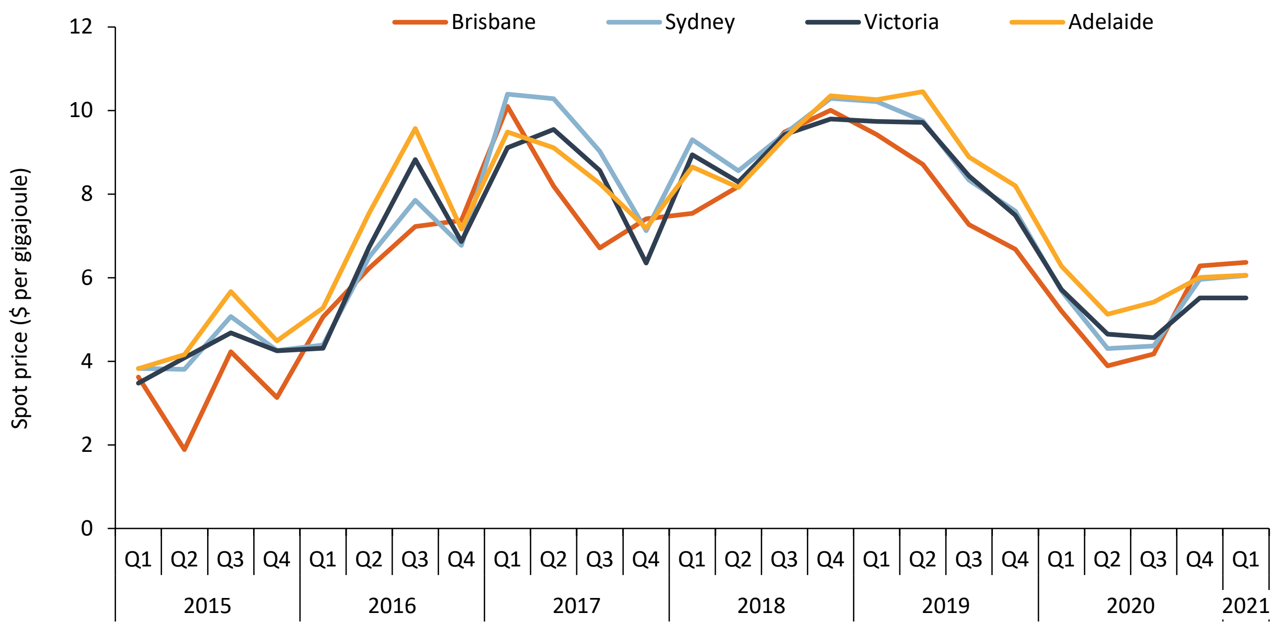



Note: Volume weighted annual averages.

Source: AER (2021).

The trend of gas prices in various regions is more similar, showing an inverted 'U' (Figure 9.15). Moreover, the trend of gas prices is like that of electricity prices after 2015. The peaks appear in Q1 of 2017 and Q1 of 2019, respectively, and there is a clear trough in Q2 of 2020.

**Figure 9.15: Eastern Australia Gas Market Prices**




Note: Adelaide, Brisbane, and Sydney prices are ex ante. The Victorian price is the 6 a.m. schedule price.

Source: AER (2021).

### 2.7 Research hypothesis

A functional electricity market will shape the relationship between the power market with high penetration of renewable energy and gas generation. Due to its capabilities of high ramp rates, quick start-ups, and relatively low emissions, the GPG provides a lower, although not zero, emission solution to the intermittence of VREs (Heinen et al., 2017). However, whether the power market with high penetrations of renewable energy can facilitate the GPG will depend on market design which needs to adequately reward the flexibility that the GPG provides in most cases (Devlin et al., 2017). In the Australian context, gas has been found to have a competitive role against coal while facilitating the development of renewables (Guidolin and Alpcan, 2019).

Nevertheless, the GPG is likely to be affected by VRE generation in the electricity generation partly because the GPG is functional as a backup for the VREs (Qadrdan et al., 2010). Therefore, we have the first hypothesis:

**Hypothesis 1**: The GPG is negatively related to VRE generation.

An increasing share of GPG results in a stronger interconnection between gas and electricity networks. The GPG is related to the electricity demand, especially peak demand (Chen et al., 2018). Moreover, high demand tends to be associated with higher wholesale energy prices. Thus, a positive correlation exists between the wholesale spot electricity price and GPG dispatch. That leads to our second hypothesis:

**Hypothesis 2:** The GPG is positively related to the electricity demand gap and electricity prices.

Higher spot gas prices usually imply higher electricity prices, and this effect is amplified at higher prices due to the convexity of the bid-supply curve (Poyrazoglu and Poyrazoglu, 2019). Therefore, we have the third hypothesis:

**Hypothesis 3:** Spot gas prices are positively related to the electricity demand gap and electricity prices.

Gas price could affect the adequacy of natural gas supply and the long-term expansion planning of electricity generation. The gas spot prices are reflected as the costs for GPG, so that gas prices will be passed through by the marginal GPG generator to the electricity price (Bolinger et al., 2006; Csereklyei et al., 2019). Therefore, we have the fourth hypothesis:

**Hypothesis 4:** Spot gas prices have mixed relationships with the GPG.

## 3 Data and Methodology

### 3.1 Data and sources

Data used in this paper include electricity generation by fuel type, daily spot electricity prices, electricity demand, and daily gas prices in four regions (NSW, Victoria, Queensland, and South Australia).[2] All data are sourced from AEMO.

1) The electricity generation dispatch data includes all units AEMO captures, namely, scheduled, semi-scheduled, and non-scheduled units in NEM, a 5-minute dispatch interval by unit (DUID). We match the electricity generation data with the region and fuel source information for each DUID and

[2] The other two jurisdictions were not included because the Australian Capital Territory is a part of the NSW electricity market while the proportion of the GPG in Tasmania is very small.

then aggregate the data by the level of date, region, fuel source,[3] and the data spans from 1 January 2011 to 28 April 2021. The Declared Wholesale Gas Market (DWGM) also provides the daily data of GPG demand in Victoria.

2) The electricity price data and electricity demand data date back to the start of NEM, 13 December 1998 to 28 April 2021.

3) The spot gas prices of NSW, Queensland, and South Australia are from the short-term trading market (STTM), which includes the date, region, ex ante market price, and provisional market price, and the period is from 1 September 2010, when the STTMs started operation, to 28 April 2021. The spot gas prices data of Victoria are from the DWGM. The data period is from 1 February 2007 to 28 April 2021. Unlike the STTM, the DWGM has multiple trading prices per day. Thus, we average those prices to produce the daily prices.

### 3.2 Methodology

In this chapter, we use different methods to test the four hypotheses, considering the relationship of variables.

To test hypotheses 1 and 2, we set up the OLS regression model for each region and the panel model for all regions as equations (1) and (2).

$$\ln gpg_t = \beta_0 + \beta_1 \ln Wind_t + \beta_2 \ln Solar_t + \beta_3 \ln ed_t + \beta_4 \ln pe_t + \beta_5 \ln gasp_t + Year_{dummy} + Season_{dummy} + \varepsilon_t \tag{1}$$

$$\ln gpg_{it} = \beta_0 + \beta_1 \ln Wind_{it} + \beta_2 \ln Solar_{it} + \beta_3 \ln ed_{it} + \beta_4 \ln pe_{it} + \beta_5 \ln gasp_{it} + Year_{dummy} + Season_{dummy} + \mu_i + v_t + \varepsilon_{it} \tag{2}$$

Where $t$ is the time and $i$ is the region. $gpg$ is the daily GPG; $Wind$ and $Solar$ are the daily power generation from wind and solar, respectively; $ed$ is the daily electricity demand gap[4]; $pe$ is the daily spot electricity price; and $gasp$ is the daily gas price. All data in the models in this paper are in logarithmic form. $Year_{dummy}$ and $Season_{dummy}$ are the dummy variables of year and season, $\mu_i$ is the region fixed effect, and $v_t$ is the time fixed effect. $\beta_1$ and $\beta_2$ are expected to be negative, while $\beta_3$ and $\beta_4$ are positive.

In hypothesis 3, to test the relationship between daily gas price and electricity demand gap, we set the OLS regression model for each region and panel model for all regions, as equations (5) and (6).

$$\ln gasp_t = \beta_0 + \beta_1 \ln ed_t + Year_{dummy} + Season_{dummy} + \varepsilon_t \tag{5}$$

$$\ln gasp_{it} = \beta_0 + \beta_1 \ln ed_{it} + Year_{dummy} + Season_{dummy} + \mu_i + v_t + \varepsilon_{it} \tag{6}$$

$\beta_1$ is expected to be positive.

Furthermore, considering the endogenous and possible causal relationship between the daily gas and electricity prices, we firstly set up VAR models for each region as equations (3) and (4) and then conducted the Granger causality test.

[3] The fuel sources include black coal, brown coal, gas, wind, hydro, solar, biomass, battery, and liquid fuel.

[4] The daily electricity demand gap is the difference between the potential electricity demand and the real electricity demand, which can be estimated by the HP filter method.

$$\ln gpsp_t = \beta_{10} + \sum_{\mathrm{k}}^{\mathrm{p}} \beta_{11k} \ln gpsp_{t-k} + \sum_{\mathrm{k}}^{\mathrm{p}} \beta_{12k} \ln pe_{t-k} + \varepsilon_{1t} \quad (3)$$

$$\ln pe_t = \beta_{20} + \sum_{\mathrm{k}}^{\mathrm{p}} \beta_{21k} \ln pe_{t-k} + \sum_{\mathrm{i}}^{\mathrm{p}} \beta_{22k} \ln gpsp_{t-k} + \varepsilon_{2t} \quad (4)$$

Where $\ln gpsp_{t-k}$ is the lag of daily gas generation price, and $\ln pe_{t-k}$ is the lag of spot electricity price. $\beta_{11}$, $\beta_{12}$, $\beta_{21,}$ and $\beta_{22}$ are expected to be positive.

To test hypothesis 4 on the mixed relationships between gas prices and the GPG, we set up VAR models as equations (7) and (8) for each region and then conducted the Granger causality test.

$$\ln gasp_t = \beta_{20} + \sum_{\mathrm{k}}^{\mathrm{p}} \beta_{21k} \ln gasp_{t-k} + \sum_{\mathrm{i}}^{\mathrm{p}} \beta_{22k} \ln gpg_{t-k} + \varepsilon_{2t} \quad (7)$$

$$\ln gpg_t = \beta_{10} + \sum_{\mathrm{k}}^{\mathrm{p}} \beta_{11k} \ln gpg_{t-k} \sum_{\mathrm{k}}^{\mathrm{p}} \beta_{12k} \ln gasp_{t-k} + \varepsilon_{1t} \quad (8)$$

Where $\ln gasp_{t-k}$ is the lag of spot gas price, and $\ln gpg_{t-k}$ is the lag of daily GPG.

In addition, as AEMO provides the data of GPG demand for Victoria, regarded as a proxy variable of GPG, we set a robustness test for hypotheses 1 and 2 with GPG demand data in Victoria to strengthen the conclusions of this paper.

# 4 Empirical Results

## 4.1 Unit root test for time series

Firstly, we conduct the unit root tests for time series, and the results are shown in Table 9.3. The *p* value of each time series is less than 0.01, which means each series is stationary and can set up regression models directly with them.

**Table 9.1: Unit Root Test Results**

| Variables | NSW | OLD | SA | VIC | Panel |
|---|---|---|---|---|---|
| Ln (GPG dispatch) | -22.845<br>(0.000) | -13.748<br>(0.000) | -24.124<br>(0.000) | -28.678<br>(0.000) | -56.213<br>(0.000) |
| Ln( GPG demand) | | | | -34.575<br>(0.000) | |
| Ln (Wind generation) | -24.841<br>(0.000) | -10.068<br>(0.000) | -37.749<br>(0.000) | -31.602<br>(0.000) | -65.547<br>(0.000) |
| Ln (Solar generation) | -9.185<br>(0.000) | -10.726<br>(0.000) | -10.745<br>(0.000) | -9.943<br>(0.000) | -34.714<br>(0.000) |
| Ln (Gas price) | -13.727<br>(0.000) | -14.181<br>(0.000) | -8.214<br>(0.000) | -12.416<br>(0.000) | -24.614<br>(0.000) |
| Ln (Electricity price) | -20.780<br>(0.000) | -27.023<br>(0.000) | -32.592<br>(0.000) | -22.121<br>(0.000) | -69.594<br>(0.000) |
| HP_Ln(Electricity demand gap) | -22.988<br>(0.000) | -19.933<br>(0.000) | -26.299<br>(0.000) | -28.323<br>(0.000) | -51.112<br>(0.000) |

Note: In parentheses is the *p* value corresponding to the statistical value.

Source: Authors' calculations.

## 4.2 Natural gas's flexibility role in the power system

The first empirical question is whether the GPG has been functioning as a flexible and dispatchable power source in the national market. This flexibility role can be tested through two relationships: (i)

GPG and the wind or solar power dispatch for GPG's backup role to VREs (hypothesis 1), and (ii) GPG and the total electricity demand for GPG's peak generator role (hypothesis 2). In each case, the dependent variable is GPG dispatch, and the core explanatory variable is wind generation and solar generation, electricity demand gap, respectively. Table 9.4 shows the empirical results for panel data, and Table 9.5 shows the results for the regions.

Firstly, the coefficient of wind generation is negative and significant at the 1% level for the panel data, as shown in columns (1), (5)–(7) of Table 9.4. And as shown in Table 9.5, the coefficient of wind generation is also significantly negative in NSW, South Australia, and Victoria, but not significant in Queensland. Four states rely on GPG differently. In NSW, South Australia, and Victoria, GPG was squeezed due to lower grid demand and higher wind and solar output. However, the main reason for the slumping GPG in Queensland is the increasing gas fuel cost due to the start of Queensland's LNG industry rather than wind generation.

Moreover, the wind generation proportion in Queensland is the lowest in NEM. Thus, the negative effect of wind on GPG is not significant in Queensland. In addition, the coefficient of the solar generation is negative and significant at the 1% level for panel data in columns (5) to (7) of Table 9.4. And the coefficient of solar generation is also significantly negative in NSW, Queensland, and Victoria when the dependent variable is GPG dispatch but not significant in Victoria when the dependent variable is GPG demand. The coefficient is positive and significant at the 1% level in South Australia. The inconsistent coefficients of solar generation may be related to its scale. Compared to the GPG, the scale of solar generation is still small in some regions and does not have enough substitution effect on the GPG. Especially in South Australia, the proportion of GPG is the highest, and the scale of solar generation is the lowest.

On the average effect of VREs on the GPG, when the wind and solar generation increases by 1%, the GPG will decrease by an average of 0.079% and 0.113%, as in column (7) of Table 9.4. The negative effect of wind generation on the GPG is the largest in South Australia and is the smallest in Queensland. The negative effect of solar generation on the GPG is the largest in NSW and is the smallest in Queensland. But in South Australia, the relationship is positive. The GPG increases in South Australia may mainly link to the demand gaps due to the closure of coal power stations. Also, South Australia relies on the GPG more than other states. Thus, even though solar generation is growing, the GPG also increases to meet the demand gaps.

The significantly negative coefficients of wind and solar generation in most models provide sufficient support for hypothesis 1, namely, the GPG is negatively related to the generation from VREs.

Secondly, the coefficients of electricity demand gap are positive and significant at the 1% level for the panel data and all regions (Tables 9.4 and 9.5). And when the electricity demand gap increases by 1%, the GPG will increase by an average of 3.184%. The positive effect is the largest in NSW and is the smallest in South Australia. The significantly positive coefficients support hypothesis 2, namely, the GPG is positively related to the electricity demand gap.

**Table 9.2: Testing Natural Gas's Flexibility Role in Power System (for Panel Data)**

| Dependent Variable | GPG Dispatch | | | | | | |
|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) |
| Wind generation | -0.330*** | | | | -0.295*** | -0.221*** | -0.079** |
| | (0.016) | | | | (0.031) | (0.030) | -0.031 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Solar generation | | 0.019 | | | -0.225$^{***}$ | -0.089$^{**}$ | -0.113$^{***}$ |
| | | (0.028) | | | (0.044) | (0. 043) | -0.044 |
| Electricity demand gap | | | 3.872$^{***}$ | | | 4.507$^{***}$ | 3.184$^{***}$ |
| | | | (0.100) | | | (0.205) | (0.237) |
| Electricity price | | | | 1.088$^{***}$ | | | 1.085$^{***}$ |
| | | | | (0.030) | | | (0.068) |
| Gas price | | | | | | | -0.317$^{***}$ |
| | | | | | | | (0.116) |
| Constant | 11.049$^{***}$ | 9.337$^{***}$ | 8.726$^{***}$ | 5.199$^{***}$ | 14.154$^{***}$ | 12.672$^{***}$ | 8.227$^{***}$ |
| | (0.137) | (0.210) | (0.039) | (0.107) | (0.392) | (0.382) | (0.485) |
| Year_dummy | Yes | Yes | Yes | Yes | Yes | Yes | Yes |
| Season_dummy | Yes | Yes | Yes | Yes | Yes | Yes | Yes |
| Adj $R^2$ | 0.059 | 0.109 | 0.119 | 0.124 | 0.068 | 0.09 | 0.085 |
| N | 12,217 | 7,264 | 15,008 | 14,612 | 5,300 | 5,300 | 5,112 |

Source: Authors' calculations.

**Table 9.3: Testing Natural Gas's Flexibility Role in Power System (for Regional Data)**

| Dependent Variable | GPG Dispatch | | | | GPG Demand |
|---|---|---|---|---|---|
| | NSW | QLD | SA | VIC | VIC |
| | (1) | (2) | (3) | (4) | (5) |
| Wind generation | -0.136$^{***}$ | -0.019 | -0.240$^{***}$ | -0.221$^{***}$ | -0.235$^{**}$ |
| | (0.065) | (0.014) | (0.013) | (0.060) | (0.116) |
| Solar generation | -0.362$^{***}$ | -0.129$^{***}$ | 0.024$^{**}$ | -0.146$^{**}$ | -0.106 |
| | (0.123) | (0.032) | (0.011) | (0.068) | (0.134) |
| Electricity demand gap | 5.848$^{***}$ | 2.880$^{***}$ | 1.172$^{***}$ | 3.367$^{***}$ | 2.033$^{**}$ |
| | (0.565) | (0.169) | (0.054) | (0.478) | (0.924) |
| Electricity price | 3.348$^{***}$ | 0.193$^{***}$ | 0.152$^{***}$ | 1.522$^{***}$ | 2.491$^{***}$ |
| | (0.202) | (0.033) | (0.016) | (0.132) | (0.220) |
| Gas price | -1.361$^{***}$ | -0.584$^{***}$ | 0.364$^{***}$ | 0.186 | 0.52 |
| | (0.198) | (0.053) | (0.053) | (0.300) | (0.574) |
| Constant | 1.806 | 10.899$^{***}$ | 10.224$^{***}$ | 3.622$^{***}$ | -10.012$^{***}$ |
| | (1.198) | (0.337) | (0.201) | (1.101) | (2.102) |
| Year_dummy | Yes | Yes | Yes | Yes | Yes |
| Season_dummy | Yes | Yes | Yes | Yes | Yes |
| Adj $R^2$ | 0.433 | 0.566 | 0.748 | 0.443 | 0.366 |
| N | 2,157 | 974 | 971 | 1010 | 1,046 |

Source: Authors' calculations.

### 4.3 GPG's response to market price signals

In a market setting, price signals reflect the gaps between supply and demand. Therefore, this empirical test will check how much GPG will respond to electricity prices. As in the previous case, there are estimations in panel data models (Table 9.4) and a separate estimation for each regional electricity market (Table 9.5).

Columns (4) and (7) of Tables 9.4 and 9.5 show that the coefficients of electricity prices are positive and significant at the 1% level for the panel data and all regions. And when the electricity price increases by 1%, the GPG increases by an average of 1.085%. The positive effect is the largest in NSW and is the smallest in South Australia, which is the same as the effect of the electricity demand gap. In 2020, the GPG fell in NSW mainly due to low electricity prices. However, in South Australia, the reduced generation coincided with the closure of two units at gas-powered plants, which may have resulted in the smallest positive effect of electricity price on the GPG. The significantly positive effect of electricity prices on the GPG also supports hypothesis 2, namely, the GPG is positively related to electricity prices.

## 4.4 Interrelationship between gas and electricity prices

The active role of the GPG in the power market will form a close relationship between the natural gas market and the electricity markets. These will have two sub-hypotheses:

### *4.4.1 Spot gas prices will positively respond to electricity prices*

We construct a VAR model and Granger causality test to explore the relationship between gas prices and electricity prices for the hypothesis. The results are shown in Tables 9.6 and 9.7.

It can be seen that electricity prices of a day lag period have a positive impact on the gas prices, and gas prices of a day and 2 days lag period also positively impact the electricity prices. In addition, the gas price does Granger-cause electricity price, and electricity price also does Granger-cause gas price in all four regions.

**Table 9.4:** **The Relationship between Gas and Electricity Prices**

| | NSW | QLD | SA | VIC | Panel(FE) |
|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) |
| Dependent variable: Gas price | | | | | |
| L1. Gas price | $0.622^{***}$ | $0.660^{***}$ | $0.753^{***}$ | $0.712^{***}$ | $0.671^{***}$ |
| | (0.016) | (0.017) | (0.016) | (0.016) | (0.008) |
| L2. Gas price | $0.241^{***}$ | $0.214^{***}$ | $0.208^{***}$ | $0.208^{***}$ | $0.227^{***}$ |
| | (0.016) | (0.017) | (0.016) | (0.016) | (0.008) |
| L1. Electricity price | $0.096^{***}$ | $0.113^{***}$ | $0.021^{***}$ | $0.027^{***}$ | $0.055^{***}$ |
| | (0.015) | (0.017) | (0.003) | (0.009) | (0.005) |
| L2. Electricity price | 0.011 | -0.018 | $-0.009^{***}$ | 0.004 | $0.000^{***}$ |
| | (0.014) | (0.016) | (0.003) | (0.009) | (0.005) |
| Constant | $-0.194^{***}$ | $-0.173^{***}$ | 0.015 | 0.009 | $-0.050^{***}$ |
| | (0.033) | (0.048) | (0.010) | (0.019) | (0.014) |
| Dependent variable: Electricity price | | | | | |
| L1. Electricity price | $0.607^{***}$ | $0.507^{***}$ | $0.378^{***}$ | $0.628^{***}$ | $0.511^{***}$ |
| | (0.014) | (0.016) | (0.016) | (0.016) | (0.008) |
| L2. Electricity price | $0.145^{***}$ | $0.136^{***}$ | $0.089^{***}$ | $0.065^{***}$ | $0.129^{***}$ |
| | (0.014) | (0.015) | (0.016) | (0.015) | (0.008) |
| L1. Gas price | $0.103^{***}$ | $0.091^{***}$ | $0.454^{***}$ | $0.182^{***}$ | $0.145^{***}$ |

| | | | | | |
|---|---|---|---|---|---|
| | (0.015) | (0.015) | (0.081) | (0.028) | (0.013) |
| L2. Gas price | 0.042*** | 0.049*** | -0.016 | 0.054* | 0.064*** |
| | (0.015) | (0.015) | (0.080) | (0.028) | (0.012) |
| Constant | 0.729*** | 1.174*** | 1.334*** | 0.796*** | 1.055*** |
| | (0.031) | (0.044) | (0.050) | (0.034) | (0.021) |
| N | 3,713 | 3,352 | 3,452 | 3,665 | 14,182 |

Source: Authors' calculations.

**Table 9.5: Granger Causality Wald Tests for Gas and Electricity Prices**

| | | H0: Electricity Price Does not Granger-cause Gas Price | H0: Gas Price Does not Granger-cause Electricity Price |
|---|---|---|---|
| NSW | chi2 | 103.560 | 245.860 |
| | P | 0.000 | 0.000 |
| QLD | chi2 | 59.661 | 239.080 |
| | P | 0.000 | 0.000 |
| SA | chi2 | 41.200 | 316.690 |
| | P | 0.000 | 0.000 |
| VIC | chi2 | 21.602 | 274.390 |
| | P | 0.000 | 0.000 |

NSW = New South Wales, QLD = Queensland, SA = South Australia, VIC = Victoria.

Source: Authors' calculations.

### *4.4.2 Spot Gas Prices are Positively Related to Electricity Demand*

We construct the OLS model and panel fixed model to test the relationship between gas prices and electricity demand, and the results are shown in Table 9.8. It can be seen that the coefficients of electricity demand are positive and significant at the 1% level for all models. This means that the electricity demand is positively related to gas prices; when electricity demand increases by 1%, gas prices increase by an average of 0.463%. The positive impact of electricity demand on gas prices is the largest in Queensland and the smallest in South Australia.

Hence, the results of Tables 9.6 to 9.8 support hypothesis 3 that spot gas prices are positively related to electricity prices and electricity demand.

**Table 9.6: The Relationship between Gas Prices and Electricity Demand**

| Dependent Variable | Gas Price NSW (1) | QLD (2) | SA (3) | VIC (4) | Panel (FE) (5) |
|---|---|---|---|---|---|
| Electricity demand | 0.733*** | 0.781*** | 0.288*** | 0.475*** | 0.463*** |
| | (0.056) | (0.134) | (0.019) | (0.038) | (0.025) |
| Constant | 0.983*** | 1.190*** | 1.231*** | 0.991*** | 1.072*** |
| | (0.017) | (0.087) | (0.010) | (0.014) | (0.011) |
| Year_dummy | Yes | Yes | Yes | Yes | Yes |

| | | | | | |
|---|---|---|---|---|---|
| Season_dummy | Yes | Yes | Yes | Yes | Yes |
| Adj $R^2$ | 0.681 | 0.523 | 0.810 | 0.747 | 0.594 |
| N | 3,764 | 3,426 | 37548 | 3,761 | 14,705 |

Source: Authors' calculations.

### 4.5 Interrelation between the GPG and gas prices

We construct a VAR model and Granger causality test to test the relationship between the GPG and gas prices. Tables 9.9 and 9.10 show that the GPG of a day's lag period has a significant positive impact on gas prices in South Australia and Victoria but has no significant impact in NSW and Queensland and the panel data. The GPG of 2 days lag period has a significant negative impact on gas prices in all regions and the panel data. The gas prices of a day lag period have a significant positive impact on the GPG in South Australia and Victoria. Still, they have no significant impact on NSW, Queensland, and panel data. But the GPG of 2 days lag period has a significant negative impact on gas prices in NSW, Queensland, and panel data, consistent with the results in Table 9.5.

Although the effect of independent variables 1 day lag period on dependent variables varies in different regions, the coefficients 2 days lag period are negative. So, the relationship between the GPG and gas price is roughly negatively correlated.

The Granger causality Wald test results show that the GPG does Granger-cause gas prices in all four regions, and gas prices also do Granger-cause GPG in all regions.

**Table 9.7: The Relationship between Gas-powered Generation (GPG) and Gas Prices**

| | NSW<br>(1) | QLD<br>(2) | SA<br>(3) | VIC<br>(4) | Panel(FE)<br>(5) |
|---|---|---|---|---|---|
| Dependent variable:<br>Gas price | | | | | |
| L1. Gas price | 0.660*** | 0.668*** | 0.750*** | 0.685*** | 0.687*** |
| | (0.016) | (0.017) | (0.016) | (0.016) | (0.008) |
| L2. Gas price | 0.268*** | 0.212*** | 0.226*** | 0.258*** | 0.246*** |
| | (0.016) | (0.017) | (0.016) | (0.016) | (0.008) |
| L1. GPG | -0.001 | -0.028 | 0.044*** | 0.006*** | 0.002 |
| | (0.002) | (0.026) | (0.005) | (0.002) | (0.002) |
| L2.GPG | -0.005** | -0.064** | -0.046*** | -0.006*** | -0.007*** |
| | (0.002) | (0.026) | (0.005) | (0.002) | (0.002) |
| Constant | 0.167*** | 1.114*** | 0.070** | 0.095*** | 0.151*** |
| | (0.019) | (0.137) | (0.034) | (0.015) | (0.013) |
| Dependent variable:<br>GPG | | | | | |
| L1. GPG | 0.641*** | 0.933*** | 0.809*** | 0.603*** | 0.650*** |
| | (0.016) | (0.017) | (0.016) | (0.017) | (0.008) |
| L2. GPG | 0.129*** | -0.078*** | -0.117*** | 0.015 | 0.089*** |
| | (0.016) | (0.017) | (0.016) | (0.017) | (0.008) |
| L1. Gas price | 0.041 | -0.014 | 0.112** | 0.348*** | 0.060 |
| | (0.117) | (0.011) | (0.053) | (0.127) | (0.040) |
| L2. Gas price | -0.344*** | -0.044*** | -0.077 | -0.033 | -0.137*** |
| | (0.015) | (0.011) | (0.053) | (0.126) | (0.040) |

| | (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|---|
| Constant | 2.403*** | 1.529*** | 2.900*** | 2.412*** | 2.429*** |
| | (0.144) | (0.091) | (0.114) | (0.118) | (0.064) |
| **N** | **3,723** | **3,422** | **3,750** | **3,669** | **14,564** |

Source: Authors' calculations.

**Table 9.8*: Granger Causality Wald Tests for Gas-powered Generation (GPG) and Gas Prices***

| | | **H0: GPG Does not Granger-cause Gas Price** | **H0: Gas Price Does not Granger-cause GPG** |
|---|---|---|---|
| NSW | chi2 | 13.757 | 40.351 |
| | P | 0.001 | 0.000 |
| QLD | chi2 | 51.611 | 91.476 |
| | P | 0.000 | 0.000 |
| SA | chi2 | 97.484 | 10.909 |
| | P | 0.000 | 0.004 |
| VIC | chi2 | 10.453 | 43.193 |
| | P | 0.005 | 0.000 |

Source: Authors' calculations.

# 5 Policy Implications for ASEAN and Latecomers

With a total GDP of US$3.1 trillion in 2017, ASEAN is the fifth-largest economy in the world, only after the United States, China, Japan, and Germany. The ASEAN economy is expected to grow to US$12.25 trillion in 2050. Under the business-as-usual scenario (BAU), ASEAN's total final energy demand is expected to grow from 480 Mtoe in 2017 to 1,355 Mtoe in 2050, and its emissions will increase from 375 Mt CO2 (Mt-C) equivalent to 1,216 Mt-C (Han and Kimura, 2021). Although the share of electricity in ASEAN's total final energy consumption (TFEC) will increase modestly from 16.5% in 2017 to 20.65% in 2050 in BAU, the total electricity output will increase threefold from 1,041 TWh to 3,439 TWh in BAU and 2,895 TWh in the alternative policy scenario (APS) during the same period.

Unfortunately, fossil fuels will still count for 72% of the generation mix even in the APS, while VREs will account for only 12.3% in 2050. Due to the low electricity share in the TFEC and the generation mix, emissions in ASEAN are expected to increase from 375 Mt-C to 876 Mt-C in 2050 (Han and Kimura, 2021). In the context of global consensus on fighting climate change, the ASEAN region needs to take immediate actions to reduce future carbon emissions through measures such as more gas use and renewable energies.

Given the high share of fossil fuels (78% share of oil, coal, and natural gas) in ASEAN's energy mix, ASEAN must advance the decarbonising process, which requires policy commitments and significant efforts. However, although Singapore has announced its plan to achieve net-zero emissions beyond 2050, many ASEAN countries have yet to set any net-zero emissions target.

Natural development in decarbonising energy mix is possible. Since VREs such as solar and wind have contributed negligible amounts (2.4% in 2020) to the power mix (Han et al., 2021), the future growth potential is there. However, due to their low starting level, renewables such as biomass, wind, and solar are expected to increase largely by 93%. This is because of the upscaling of renewable policy in ASEAN. Such rapid growth requires grid-stabilising techniques to accommodate the increasing penetration of VREs.

ASEAN's rich natural gas reserves provide a much-needed technical option to manage the challenges from large shares of VREs, but there is no market to reward gas's role. Due to its flexibility in generation, natural gas generation can reduce emissions (compared with coal power generation), provide power system flexibility, and maintain national security (compared with imported electricity). Natural gas accounts for 40% of the ASEAN generation mix, an asset for advancing VREs. Given the urgent and critical need for transitioning to low-carbon energies, especially to decarbonise the grid electricity sector, many ASEAN governments will need to implement deeper electricity market reforms to accommodate clean and renewable electricity.

ASEAN is stepping behind Australia's electricity sector from three perspectives: (i) the linearisation of the electricity sector, (ii) the development of electricity markets, and (iii) the increasing penetration of renewable energy. Many ASEAN countries embarked on electricity reform from the centrally or vertically integrated stated ownership to the hybrid market–based system in which state-owned utility remains the 'single buyer', and the private sector joins in the supply of electricity as 'independent power producers'. However, the ASEAN electricity markets are not competitive in most countries except the Philippines and Singapore. Given the current electricity market in ASEAN, attracting new investment in this sector is very hard. It is especially difficult to introduce the high share of renewables and innovative technologies such as smart grids, which will allow more renewable energy penetration technically.

Therefore, the Australian experience can inform ASEAN on electricity sector development and renewable energy. In the absence of competitive markets, natural gas generation, despite being flexible, would not deliver the flexibility as contractual and other institutional constraints prevent them from being a mate of VREs.

Our estimation results of Australia's NEM indeed suggest that a well-functioning electricity market can reward the flexible role of natural gas, and a competitive market is certainly conducive to the development of renewable energies. Therefore, we could generate the following implications from our study.

First, ASEAN should leverage the flexible role of natural gas. Such a significant role in the ASEAN generation mix is an asset. Thus, efforts should be made to generate gas pricing signals to timely react to power market needs.

Second, ASEAN should continuously liberalise its electricity markets and establish a merit-order competitive electricity market. Confirmed significant roles of the electricity market in promoting the GPG can shed light on ASEAN's future policies on the electricity markets.

Third, ASEAN needs to continuously promote regional integration as another cost-effective policy to handle the increasing penetration of VREs. ASEAN countries have complementary energy resources, and the abundance of hydropower resources in the Greater Mekong Subregion is an asset to offset the volatilities from the VREs. Therefore, the penetration of solar PV and wind in ASEAN could be advanced by power connectivity and trade within ASEAN (IRENA, 2018; Shi, 2016).

A framework that can combine the gas and electricity markets should be established. Due to the increasing penetration of VREs, power systems are relying more on the flexibility roles of the GPG, which will gradually link the currently separated gas and electricity markets (Chen et al., 2018; Heinen et al., 2017). However, the existing market framework is not conducive: neither reliable nor efficient, and economically unfriendly to GPG investors (Heinen et al., 2017). A framework that combines the two markets and properly prices the scarce resources, e.g. gas transmission capacity, is required to efficiently allocate resources while satisfying the demand (Heinen et al., 2017).

## 6 Conclusion

Natural gas is considered a natural partner for VREs due to its flexibility in generation at affordable prices. However, whether the GPG can play such a flexible role in the generation mix depends on such flexibility being rewarded. A competitive electricity market rewards peak prices to GPG and is expected to be a reason to liberalise the electricity markets. Empirical evidence of a competitive market's role in GPG development can inform future electricity market reform, mainly in developing countries.

This chapter theoretically analyses the relationship between the competitive electricity market and the GPG and hopes to take Australia's energy transformation as an example to give ASEAN some constructive suggestions. First, based on the literature review, this chapter puts forward several assumptions on the relationship between the electricity market and Australia's GPG. Then it verifies the hypotheses by constructing OLS, panel, and VAR models, and the Granger causality test with the daily data from AEMO.

The empirical tests fully support the hypotheses: (i) that the GPG is negatively related to generation from VREs and positively related to electricity demand gap and electricity prices, (ii) spot gas prices are positively related to electricity prices and electricity demand, and (iii) spot gas prices have mixed relationships with the GPG. Therefore, the findings suggest that ASEAN should boost gas use and continue electricity market liberalisation and regional electricity market integration.

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