Victorian GPG forecasts

A REPORT PREPARED FOR APA GROUP

December 2016

Victorian GPG forecasts

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Glossary

Table 1: Glossary

AEMO	Australia Energy Market Operator
Carbon price	A penalty on carbon emissions
EIT	Emissions Intensity Target: a form of emissions trading
ERF	Emissions Reduction Fund: part of the Federal Government (Coalition) Direct Action plan to reduce emissions. The ERF is a voluntary fund whereby the Government contracts to purchase emissions **reductions** on a project basis.
ETS	Emissions Trading Scheme
EU ETS	European Union Emissions Trading Scheme
EUA	EU Allowance (tradeable certificates under the EU ETS)
GWh	Gigawatt hour
GPG	Gas powered generation
LGC price	Large Scale Generation Certificate (LGC): subsidy credits as part of the LRET
LRET	Large scale renewable energy target
LRMC	Long-run marginal cost = SRMC + fixed operating and maintenance costs + capex (amortised capital costs, for new investment)
MWh	Megawatt hour
NEM	National Electricity Market
NEFR	National Electricity Forecasting Report
PJ	Petajoule
PPA	Power Purchase Agreement: a long term contract with a fixed bundled price for energy and LGCs
Rooftop Solar PV	Small (rooftop) solar photovoltaic panels. This energy is not traded in the NEM, but does contribute to reduced demand for energy from NEM energy.
SRES	Small scale renewable energy scheme (for rooftop solar PV)
SRMC	Short-run marginal cost = fuel + variable operating and maintenance costs + carbon (if applicable)
SWIS	WA South West Interconnected System
TWh	Terawatt hour
VTS	Victorian Transmission System
VRET	Victorian Renewable Energy Target
WHIRLYGIG	Frontier's electricity market investment model

Executive summary

Frontier Economics has been engaged by APA Group to:

- provide forecasts of gas use for power generation (GPG) in the Victorian market, specifically for gas plant on the regulated VTS; and
- comment on the key differences between Frontier Economics' approach to modelling Victorian GPG demand relative to that undertaken by AEMO in its 2016 National Gas Forecasting Report (December 2016), focusing on differences in assumptions regarding a cost on carbon.

GPG forecasts

This report provides forecasts of Victorian GPG. Our **Base Case** assumptions include:

- Australian Energy Market Operator (AEMO)'s 2016 Medium electricity demand forecasts (National Electricity Forecasting Report: NEFR[1]);
- the recently announced retirement of Hazelwood from 31 March 2017[2];
- the proposed Victorian Renewable Energy Target (25% by 2020 and 40% by 2025);[3]
- **No Carbon Price**: this reflects current Federal Government policy.[4]

For the purpose of comparison with AEMO GPG forecasts, we also consider the likely impact of the introduction of an emissions target for the electricity sector (**With Carbon Price**). In our modelling for this case we assume that the sector will meet an emissions target (an input assumption) without reliance on international permit imports. The assumed sector target is consistent with Australia's 2030 national carbon emissions target (28 percent reduction on 2005 emissions by 2030).The carbon price is a model output reflecting the required price to meet the assumed target.

A full description of assumptions is provided in Table 2.

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1 https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEFR/2016/2016-National-Electricity-Forecasting-Report-NEFR.pdf

2 ENGIE Media Release, Hazelwood to close in March 2017, 03 November 2016. Available at http://www.gdfsuezau.com/media/UploadedDocuments/News/Hazelwood%20Clousure/Hazelwood%20closure%20-%20Media%20release.pdf

3 Announced June 2016: http://earthresources.vic.gov.au/energy/sustainable-energy/victorias-renewable-energy-targets

4 This position was reiterated in December 2016: http://www.abc.net.au/news/2016-12-07/frydenberg-denies-backtrack-on-emissions-intensity-scheme/8099250

Table 2: Modelling scenarios

Scenario	Demand	Gas price	Renewable capital costs	Carbon price	LRET	VRET	Hazelwood	Liddell
Base Case: No carbon price	AEMO NEFR Medium **2016**	Frontier house view: ~$6/GJ	Frontier house view (~$2349/ kW wind)	No carbon policy: no carbon price announced	33TWh by 2020, ending 2030	~1800MW to 2020 will contribute to LRET (not additional); ~3600MW additional renewables in VIC 2021-25	On 3 November 2016, ENGIE announced Hazelwood would close March 2017[5]	Closes 2022/ 2023
With Carbon price	AEMO NEFR Medium **2016**	Frontier house view: ~$6/GJ	Frontier house view (~$2349 /kW wind)	Sector target to meet 28PC reduction on 2005 by 2030, introduced by 2020 (to enable comparison with AEMO forecasts)	33TWh by 2020, ending 2030	~1800MW to 2020 will contribute to LRET (not additional); ~3600MW additional renewables in VIC 2021-25	Announced closure 31 Mar 2017	Closes 2022/ 2023
Implication for GPG forecasts	2016 demand forecast is relatively flat. Low demand reduces gas output (all else being equal).	Frontier's gas price is low compared with AEMO; this leads to higher gas output (all else equal). However, this is offset by the supply/demand balance: low demand growth / rising renewables crowd out gas and largely offset HZ closure	Drives cost of renewable schemes but minimal impact on gas output	Current policy is no carbon price. If a carbon price were introduced, this might encourage switching from coal to gas (all else equal) but this is offset by low demand growth / rising renewables which reduces any need for new/increased gas in VIC	Rising RET = new wind investment, partly offsets HZ closure	VRET to 2020 = as per LRET. VRET post 2020 = rising renewables growth in VIC. With low demand, this largely offsets the effect of HZ closure (medium/long term)	HZ closure reduces coal output; requires higher gas output short term before wind investment rises for RET	
Source	*Input assumption (3rd party forecast)*	*Frontier gas modelling output (LNG prices an input assumption)*	*Frontier input assumption*	*Emissions target is an input assumption. Carbon price is a modelling output*	*Input assumption*	*Input assumption: policy announced but not legislated*	*Input assumption (announced)*	*Input assumption (announced)*

5 ENGIE Media Release, Hazelwood to close in March 2017, 03 November 2016. Available at http://www.gdfsuezau.com/media/UploadedDocuments/News/Hazelwood%20Clousure/Hazelwood%20closure%20-%20Media%20release.pdf

Gas output by generator: Victoria

Figure 1 shows the projected annual gas use (PJ/year) by generator in Victoria for the Base Case: No Carbon Price scenario. We also present forecast gas use on the Victorian Transmission System (VTS), which excludes output from the Bairnsdale and Mortlake power stations.

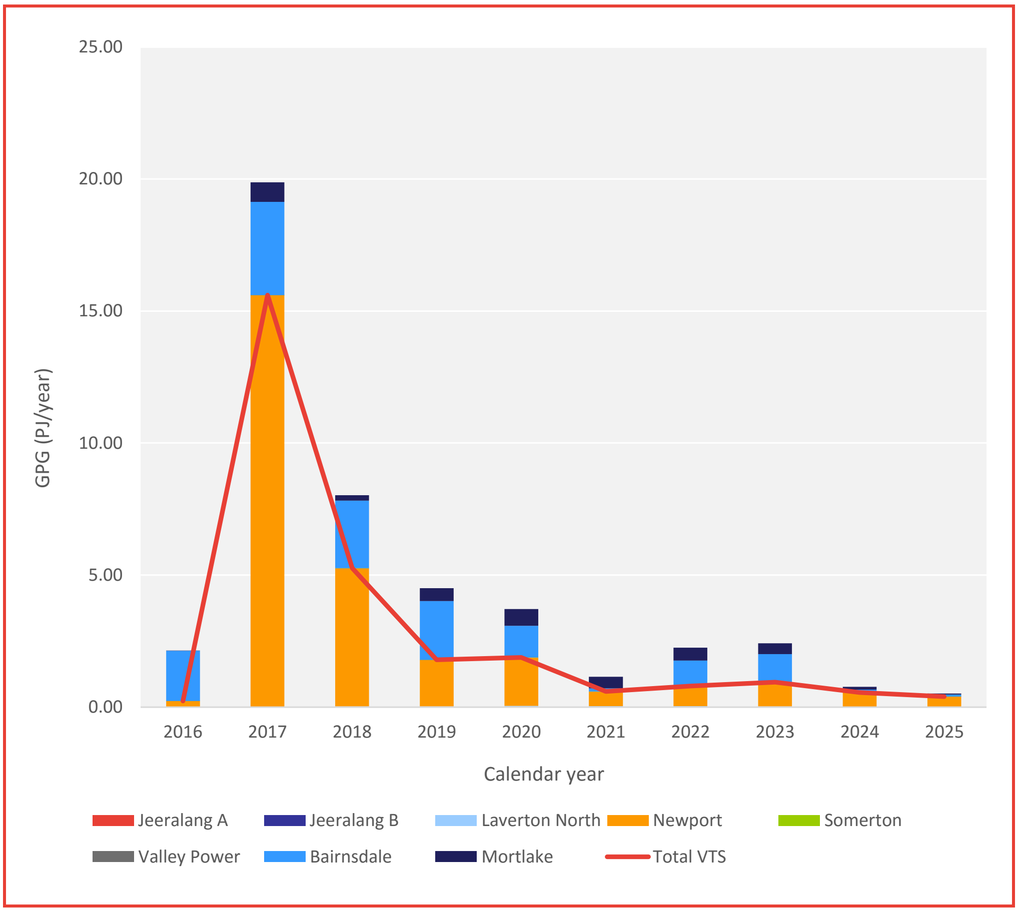
In aggregate there is a spike in gas generation in 2017 due to the closure of Hazelwood in March of that year, which is before sufficient wind can enter the market to fully replace Hazelwood's contribution to Victorian supply.

Aggregate gas use declines thereafter as wind enters the market to meet the LRET and VRET.

Individually, most of the projected output in 2017 and 2018 is from Newport and to a lesser extent Bairnsdale and Mortlake.

In recent years, Mortlake has provided more output than Newport, though we understand that this is largely due to lower historical gas prices. In our assumptions by generator (and consistent with other public forecasts), we project that it is more likely that Newport will dispatch more frequently than Mortlake, though the nature of cost-based modelling makes it difficult to accurately reflect output from peaking gas plant: even a very small difference in cost assumptions (including efficiency, fuel prices, and operating costs) will mean that one plant will invariably dispatch ahead of another, whereas in reality they may dispatch at similar levels. As such, our modelling may err on overstating Newport output at the expense of Mortlake.

Figure 1: Victorian GPG by generator, Base Case: No Carbon price



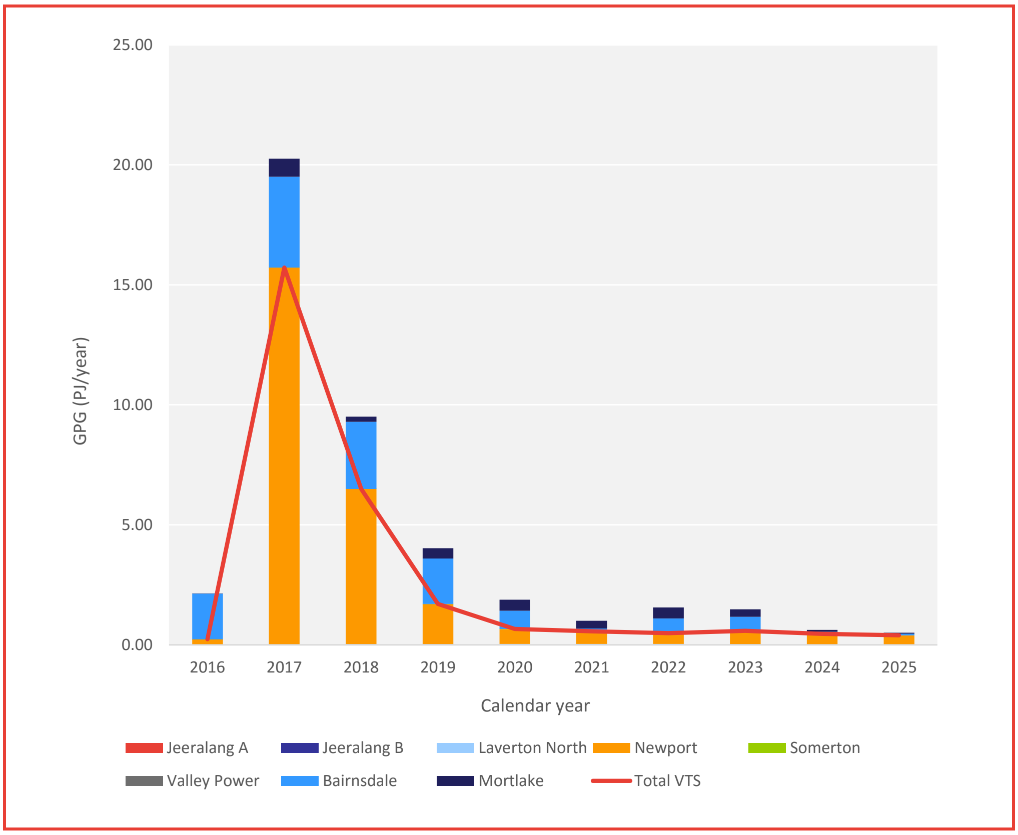
Source: Frontier Economics

Figure 21 shows the projected annual gas use (PJ/year) by generator in Victoria for the **With Carbon Price** sensitivity. These results are largely the same as the **Base Case: No Carbon Price** scenario: a combination of slow demand growth, rising LRET/VRET and the retirements of Hazelwood and Liddell results in forecast sector emissions that are already relatively close to the assumed sector target. This results in a relatively low carbon price and very little additional fuel switching (increased gas output) in Vic. Most of the transition in VIC is from brown coal to wind over the next 8 years in VIC (due to renewables policies). The carbon price does drive some increase in output from gas fired generation in QLD and NSW, though we forecast limited opportunity for increased gas-fired output in VIC due to the large growth of new wind output.

This is partly due to our assumption of an emissions target for the electricity sector without linkage with other sectors or international schemes. If the sector were to face an emissions trading scheme that is linked internationally then we would expect that Australia, as a small emitter, would be a price taker in international carbon markets. Indicatively, the 2020 forward price for EU Allowances (EUAs), which are the certificates traded in the EU Emissions Trading Scheme (ETS) as at

16 December 2016 is 5EUR/tCO2[6], which is approximately $AUD7/tCO2. This is less than the carbon price forecast that we have modelled. This would result in less sector abatement and less gas output across the entire sector (all regions), though given the negligible differences between the Base Case and the With Carbon Price case, we wouldn't expect any material change in Vic GPG.

Figure 2: Victorian GPG by generator, With Carbon price



Source: Frontier Economics

6 https://www.theice.com/products/197/EUA-Futures/data , accessed 16 December 2016.

1 Introduction

Frontier Economics has been engaged by APA Group to:

- provide forecasts of gas use for power generation (GPG) in the Victorian market, specifically for gas plant on the regulated VTS; and
- comment on the key differences between Frontier Economics' approach to modelling Victorian GPG demand relative to that undertaken by AEMO in its 2016 National Gas Forecasting Report (December 2016), focusing on differences in assumptions regarding a cost on carbon.

This report includes the following:

- A description of our modelling approach, assumptions and scenarios
- A brief overview of the LRET
- A discussion of our modelling results

2 Modelling and assumptions

This section provides an overview of approach and assumptions. It is structured as follows:

- Modelling approach: *WHIRLYGIG*
- Scenario overview
- Key assumptions.

2.1 Modelling approach: *WHIRLYGIG*

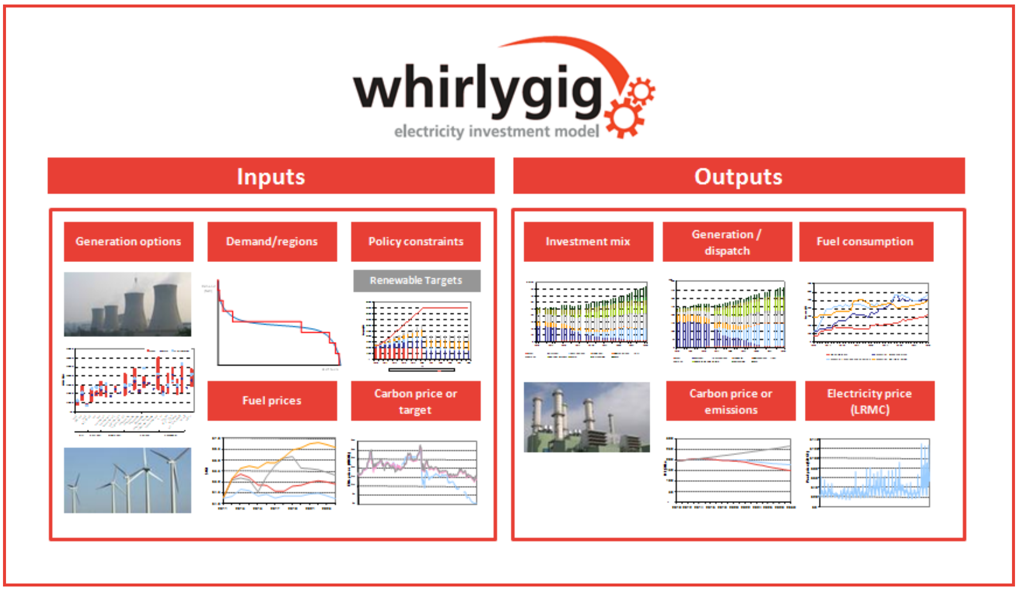
Frontier has used its proprietary electricity investment model *WHIRLYGIG* for this modelling task. *WHIRLYGIG* computes the least-cost mix of generation (output) and investment to meet demand, subject to meeting system reliability targets, renewable targets (for instance, the Large Scale Renewable Energy Target (LRET)), and a CO_2 emissions trading scheme or carbon price.

WHIRLYGIG models all Australian electricity markets concurrently, hence Frontier is able to accurately forecast the market outcomes of nation-wide renewable energy policy, such as the LRET and the carbon price. A diagram of high level inputs/outputs for *WHIRLYGIG* is provided in Figure 3.

Key factors affecting GPG in Victoria include:

- The demand/supply balance, in particular due to new wind entry, demand growth and the impact of Hazelwood's closure;
- Fuel prices, in particular for gas;
- Carbon prices, where applicable.

Figure 3: Model inputs and outputs



Source: Frontier Economics

2.2 Modelling scenarios

Frontier has modelled two scenarios:

- The **Base Case: No Carbon Price** scenario reflects current Federal government policy, where no carbon price is introduced.
- The **With Carbon Price** scenario considers the possible implications if we were to assume the introduction of an emissions target for the electricity sector.
  - In our modelling we assume that the sector will meet the target (an input assumption) without reliance on international permit imports.
  - Under this approach, the required carbon price to meet the emissions target is a model output, not a model input.

The key assumptions and implications are outlined in Table 3. The detailed assumptions for each are discussed in the following sections.

Table 3: Modelling scenarios

Scenario	Demand	Gas price	Renew-able capital costs	Carbon price	LRET target	VRET	Hazelwood	Liddell
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Implication for GPG forecasts	2016 demand forecast is relatively flat. Low demand reduces gas output (all else being equal).	Frontier's gas price is low compared with AEMO; this leads to higher gas output (all else equal). However, this is offset by the supply/demand balance: low demand growth / rising renewables crowd out gas and largely offset HZ closure	Drives cost of renewable schemes but minimal impact on gas output	Current policy is no carbon price. If a carbon price were introduced, this might encourage switching from coal to gas (all else equal) but this is offset by low demand growth / rising renewables which reduces any need for new/increased gas in VIC	Rising RET = new wind investment, partly offsets HZ closure	VRET to 2020 = as per LRET. VRET post 2020 = rising renewables growth in VIC. With low demand, this largely offsets the effect of HZ closure (medium/long term)	HZ closure reduces coal output; requires higher gas output short term before wind investment rises for RET	
Source	*Input assumption (3rd party forecast)*	*Frontier gas modelling output (LNG prices an input assumption)*	*Frontier input assumption*	*Emissions target is an input assumption. Carbon price is a modelling output*	*Input assumption*	*Input assumption: policy announced but not legislated*	*Input assumption (announced)*	*Input assumption (announced)*

7 ENGIE Media Release, Hazelwood to close in March 2017, 03 November 2016. Available at http://www.gdfsuezau.com/media/UploadedDocuments/News/Hazelwood%20Clousure/Hazelwood%20closure%20-%20Media%20release.pdf

2.3 Key assumptions

Frontier Economics' modelling requires a number of assumptions including new plant costs and performance characteristics, future peak demand and energy requirements, shape of load, and the likely arrangements for carbon pricing, to name a few.

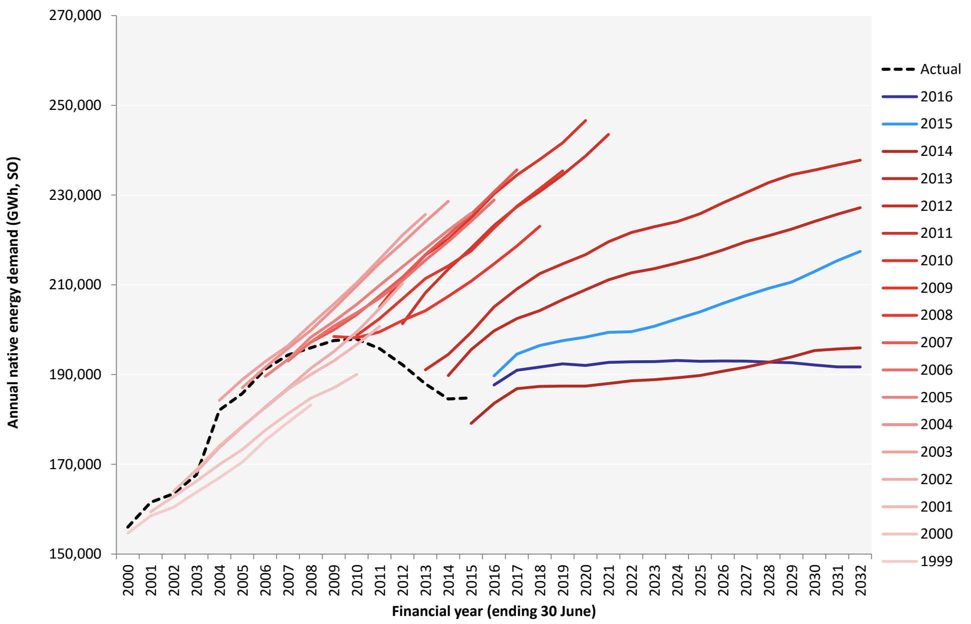
Frontier has sourced the majority of updated assumptions for this report from our in-house database.

Demand

National Electricity Market (NEM) demand has been relatively flat or falling since 2007 due to a combination of energy efficiency policies (in particular mandatory efficiency standards for appliances), solar PV uptake since 2010 (driven by very generous policy support), declining manufacturing activity (due partly to the AUD and partly due to higher electricity prices), and some demand response to higher electricity prices (mostly rising network costs). This has resulted in relatively low wholesale electricity prices. This has been exacerbated because forecasts of demand have been slow to reflect this structural break in demand growth, so new capacity continued to enter the market on the expectation of demand growth even though actual demand was falling. Figure 4 shows comparisons of forecast against actual demand. From 2007-2011, the medium forecasts produced by transmission companies and AEMO often projected continued growth though actual demand began falling.

AEMO's 2014 and 2015 Medium demand forecasts (which Frontier Economics assisted with) better accounts for the market changes since 2007/8. The latest forecasts from 2016 project relatively flat demand, largely due to the continued effects of energy efficiency policies and rooftop solar PV growth.

Figure 4 NEM demand: forecast v actual (medium cases) NEM



Each series reflects the year at the time of each forecast. Light blue reflects AEMO's 2015 Medium forecast, navy blue reflects AEMO's 2016 Medium forecasts.

Source: Frontier Economics

Gas price forecasts for gas-fired power stations

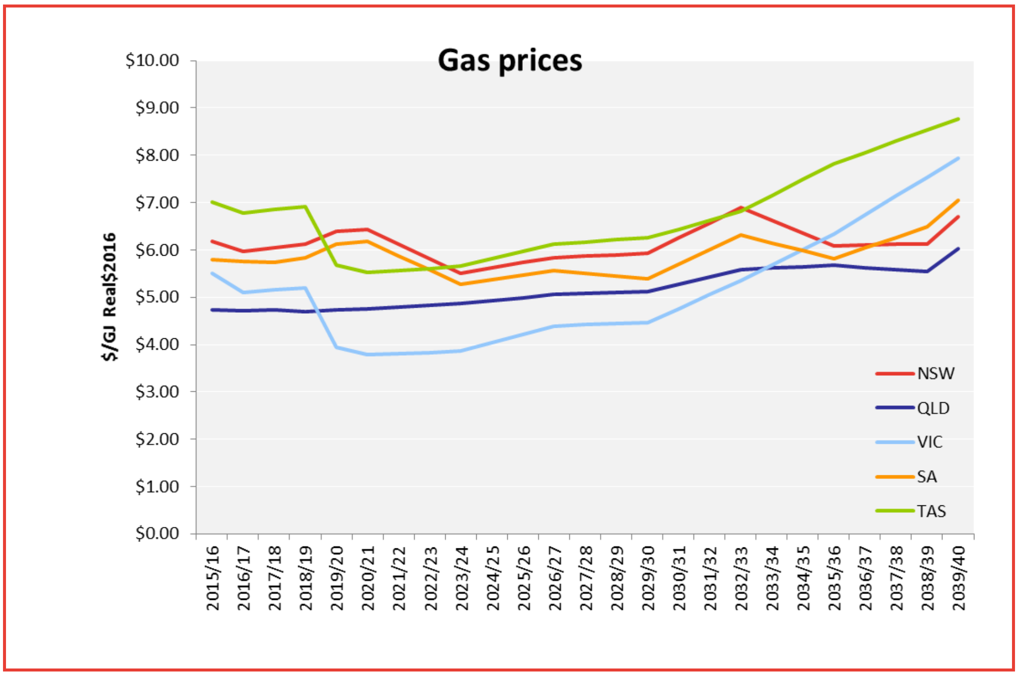
Gas prices are driven by demand for gas, international LNG prices, foreign exchange rates and underlying resource costs associated with gas extraction and transport. Frontier's gas forecasts are shown in Figure 5 for a selection of pricing zones across Australia. This incorporates the development of 6 LNG trains at Gladstone, the World Bank's most recent LNG price forecast and our central estimate of production costs for new gas projects in Australia.

The prices in this chart are used in our electricity market modelling as the cost of gas to CCGT plant, which tend to operate on a mid-merit basis at a reasonable capacity factor. OCGT plants, however, tend to operate as peakers at a much lower capacity factor. The cost of gas to an OCGT plant is likely to be higher than the cost of gas to an CCGT plant to the extent that OCGT plants consume gas when prices are higher than average. Our analysis suggests that, at the capacity factor that OCGT plants tend to operate at in the NEM, these plants are likely to face gas costs that are 50 per cent higher than the gas costs faced by CCGT plants in the same region. Based on this, the cost of gas OCGT plants that are used in our electricity market modelling is the LRMC of gas in each NTNDP Zone, increased by 50 per cent.

A full explanation of the gas forecast methodology is provided in Appendix 1.

AEMOs 2016 gas price forecasts are around $1.50/GJ higher than Frontier's house view. All else being equal, lower gas prices would generally result in higher gas-fired generation output.

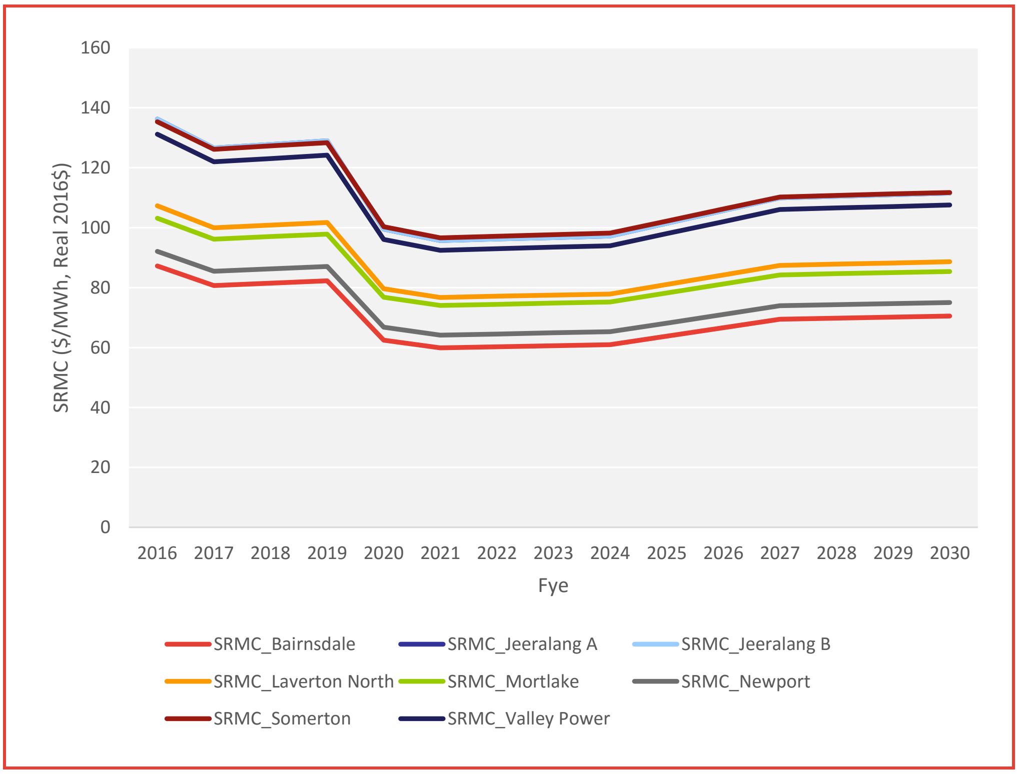
Figure 5: Delivered gas prices for power generation (CCGT) ($/GJ, Real FYe$2016)



Source: Frontier Economics

Figure 6 shows the resulting SRMC for all VIC gas generation. Differences in costs reflects variation in gas costs between CCGT/OCGT (as described above), and any variations in heat rates and variable operating and maintenance (VOM) costs. The lowest cost plant are Bairnsdale, Newport and Mortlake.

Figure 6: SRMC for VIC gas generation ($/GJ, Real FYe$2016)

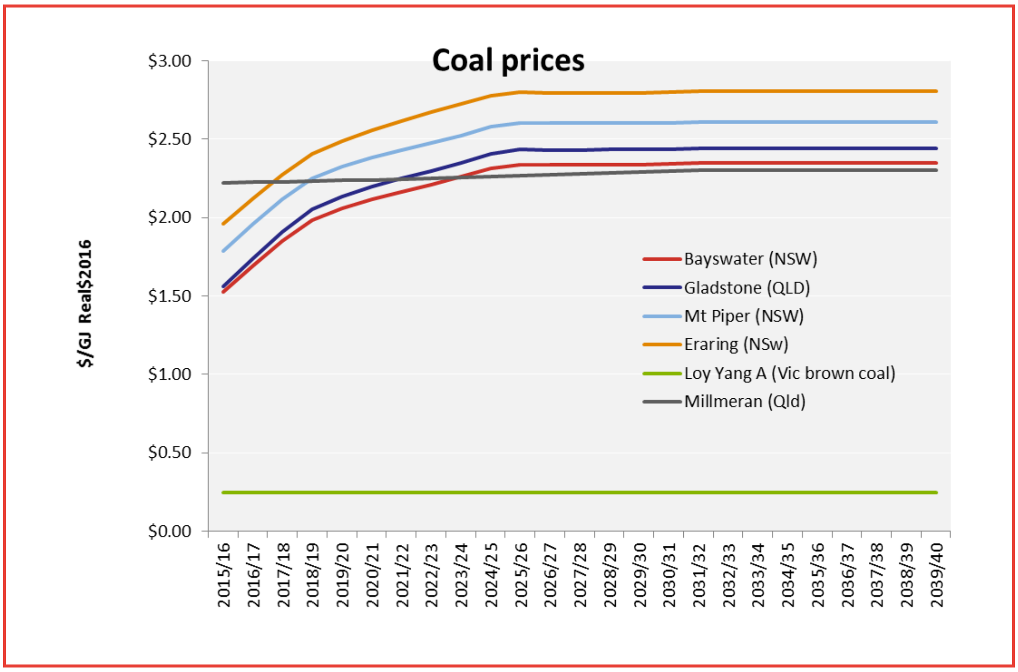


Source: Frontier Economics

Coal price assumptions for coal-fired power stations

Coal prices are driven by demand for coal, international export coal prices (for export exposed power stations), foreign exchange rates and underlying resource costs associated with coal mining. Frontier's forecasts are shown in Figure 7 for representative power stations (both export exposed and mine-mouth stations).

Figure 7: Coal prices for representative generators ($2015/16)



Source: Frontier Economics

2.4 Carbon policy

2020 target

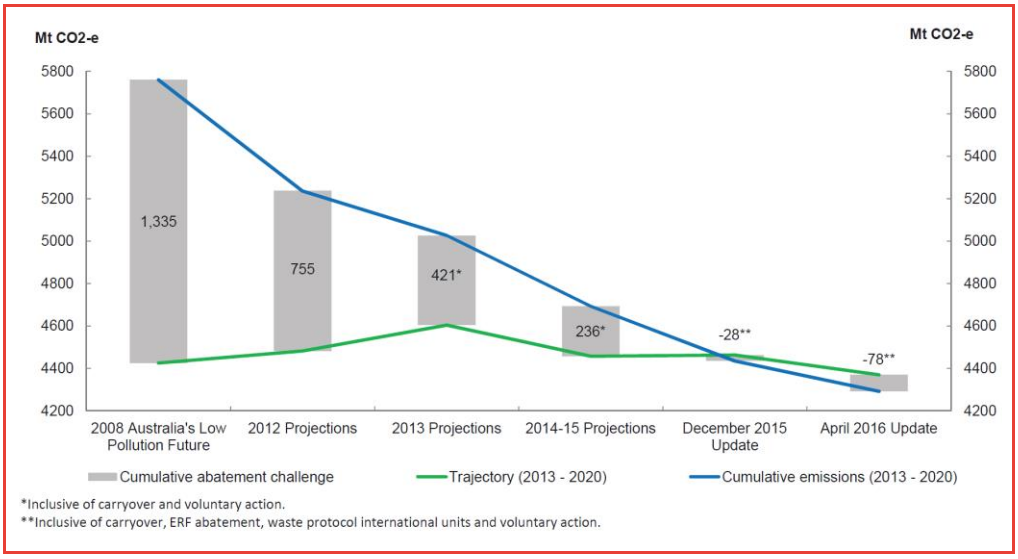
Australia has a bipartisan emissions reduction target of **five percent below 2000 levels by 2020**.

Based on official projections the projected *cumulative* 2013-2020 abatement task has fallen from 1335Mt (estimated in 2008) to 755Mt (estimated in 2012) to 421Mt (estimated in 2013) to 236Mt (March 2015) to a surplus of 28Mt (Dec 2015) and more recently 78Mt (Apr 2016).[8]

Previous Government forecasts of Australia's abatement task excluded the impact of reductions under the **Emissions Reduction Fund (ERF)**, which is a fund to purchase emissions abatement: once abatement under the ERF is taken into account (with latest information on sector emissions and policies), it is now forecast that Australia will meet the 2020 targets.

8 https://www.environment.gov.au/climate-change/publications/factsheet-tracking-to-2020-april-2016-update

Figure 8: Cumulative emissions reduction task



Source: https://www.environment.gov.au/climate-change/publications/factsheet-tracking-to-2020-april-2016-update

Currently the **ERF** has $2.55b of funds to purchase abatement prior to 2020 (though this can include payment for abatement post 2020). Credits for emissions reductions are project based according to accredited methodologies for measuring reductions. Credits can be sold to the Government via reverse auctions (conducted by the Clean Energy Regulator), which results in long term contracts for the Government to purchase abatement. No abatement has been purchased from the electricity sector.

A **safeguard mechanism**[9] also commenced from July 2016 and is intended to limit increases in emissions above a target. This is to prevent growth in emissions from some sectors cancelling out purchases of abatement from other sectors/projects, to complement the ERF.

The electricity sector has a sector baseline set at the highest point of emissions from FYe2010-2014: if this sector emissions level is exceeded then individual facility level baselines will apply. The sector peak was in 2010 (205Mt), which is not expected to be reached until after 2020 on latest projections.

9 https://www.environment.gov.au/climate-change/emissions-reduction-fund/publications/factsheet-erf-safeguard-mechanism

2030 target

The Federal Government (Coalition) proposed a target of **26-28% reduction on <u>2005</u> emissions by 2030**[10]**.** This target was announced in August 2015 and pledged at the 2015 United Nations Climate Change Conference (Paris, Dec 2015).

The ERF will increasingly rely on tightening the "Safeguards Mechanism" to limit emissions increases, and other complementary policies. The Safeguards Mechanism sets sector and facility baselines which are currently intended only to limit increases in emissions. The ERF and Safeguards Mechanisms will undergo formal review in 2017. The terms of reference for the Climate Change Review 2017[11] does not include consideration of emissions trading or carbon pricing and in December 2016 the Federal Government expressly rejected that this would be considered as part of the review.

The Federal Opposition (ALP) policy is a **45% reduction on <u>2005</u> emissions by 2030**. This also includes a proposal for an emissions intensity scheme (EIS) for reducing electricity sector emissions to 2030, along with an increased LRET to 50% and a potential payment for closure of emissions intensive generation[12].

Conclusion

For our modelling assumptions our Base Case scenario is **without a carbon price** policy (as that is the current policy position).

We also consider the possible implications for the market if a carbon price were to be introduced on the basis of an emissions target for the electricity sector (without access to international permits) to meet Australia's 2030 emissions reduction targets. For this **With Carbon Price** scenario, the carbon price is a modelling output based on the assumption that the electricity sector would face a sector target without potential for permit imports. This target for the NEM and the WA South West Interconnected System (SWIS) is based on a pro-rata of electricity sector emissions relative to National emissions. A summary of the National proposed targets by 2030 is provided in Figure 9. The implied electricity sector share of this target is 144Mt by 2030.

The model includes carbon as an additional cost to each generator (zero in the scenario without a carbon price) based on its emissions intensity. The model determines the impact of this additional cost on the merit order, how each plant is dispatched, and the extent of carbon costs passed-through to pool prices.

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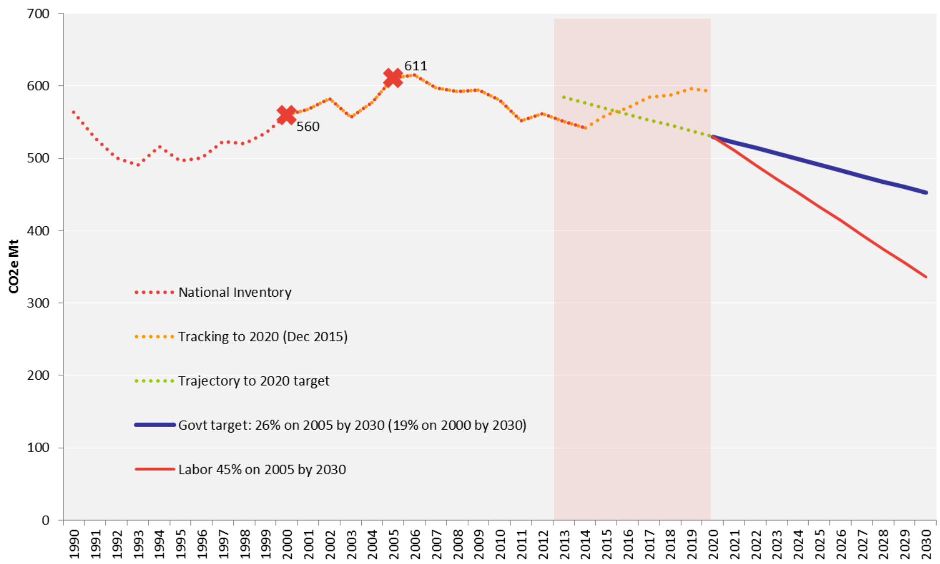
10 https://www.dpmc.gov.au/sites/default/files/publications/Summary%20Report%20Australias%202030%20Emission%20Reduction%20Target.pdf

11 http://www.environment.gov.au/climate-change/review-climate-change-policies

12 https://cdn.australianlabor.com.au/documents/Climate_change_action_plan_policy_paper.pdf

Figure 9: Emissions reduction targets (national)



Government target is 26-28%.

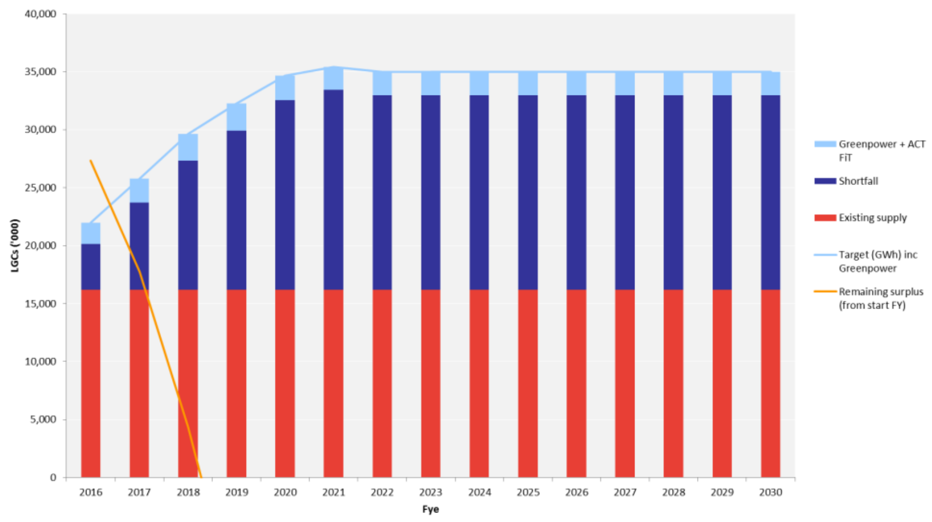
Source: Frontier Economics

2.5 LRET

The 33TWh LRET target, existing supply from large scale generation, and the current certificate surplus is represented in Figure 10. Certificate creation from existing sources, mostly wind farms, is around 16 million (TWh) per year. The current surplus of certificates is around 21 million, mostly due to the oversupply from small scale solar PV installations in 2010 before the RET was split into the LRET and the SRES. However, for the purpose of modelling (which commences from July 2015) we account for the surplus of 27 million LGCs at that time. This oversupply has reduced over the years, however has yet to be fully exhausted. Given the targets, surplus and existing supply, no additional new sources would be required until 2017/2018 if no further banking of permits occurs. However it is more likely that new investments will occur prior to then in order to continue to bank permits rather than rely entirely on the existing surplus (subject to lead times for new investment). This is accounted for in the model.

As the target currently only extends until 2030, the incentive for new renewable investments declines after around 2020 since potential revenue from LGCs ends in 2030. New entrants after 2020 will have a reduced period of LGC creation, hence would require a higher LGC price to enter the market (than if they could earn 15 years of LGCs).

Figure 10: LRET supply and demand (FY)



Existing supply refers to existing regular LGC sources (wind, hydro etc), not hydro that was pre-existing before the LRET and is ineligible for LGC creation

Source: Frontier Economics, REC registry

The LGC shortfall penalty is currently set at $65/MWh nominal. Penalties are not tax deductible, hence the effective tax-adjusted penalty is equivalent to $93 (assuming a 30% marginal tax rate). The penalty is not indexed so it declines in real terms to 2030. To the extent that the required LGC price exceeds the penalty price, the model assumes that liable entities would prefer to pay the penalty than source more expensive LGCs; this potentially caps the future LGC price at the penalty level.

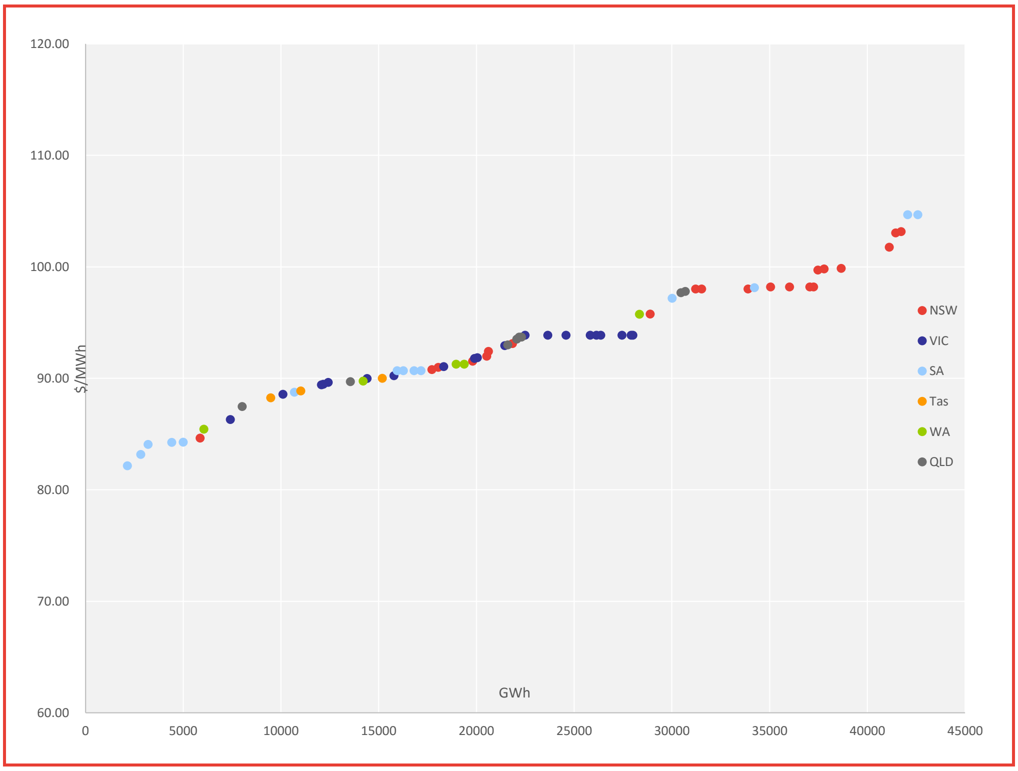
Renewable costs

Frontier's new entrant renewable costs are based on a database of existing/prospective renewable projects. The long-run marginal cost (LRMC) curve for new wind to meet the LRET is outlined in Figure 11.

Existing projects creating LGCs (wind, hydro and other) are already included in our modelling and not reflected here. The LRMC curve takes into account both the $/kW capital cost, operating costs, expected operating capacity factor of a given technology, funding costs and required return on investment.

The reduction in the target from 41TWh to 33TWh in 2015 means that the marginal wind generator is now lower on the cost curve than previously: two years ago, an additional 33TWh of new entry was required to meet the target, whereas now an additional ~17TWh is required as a result of a lower target and more committed capacity/new entrants are producing LGCs.

Figure 11: LRMC of **new** wind projects available to meet LRET ($/MWh, FYend $2016)



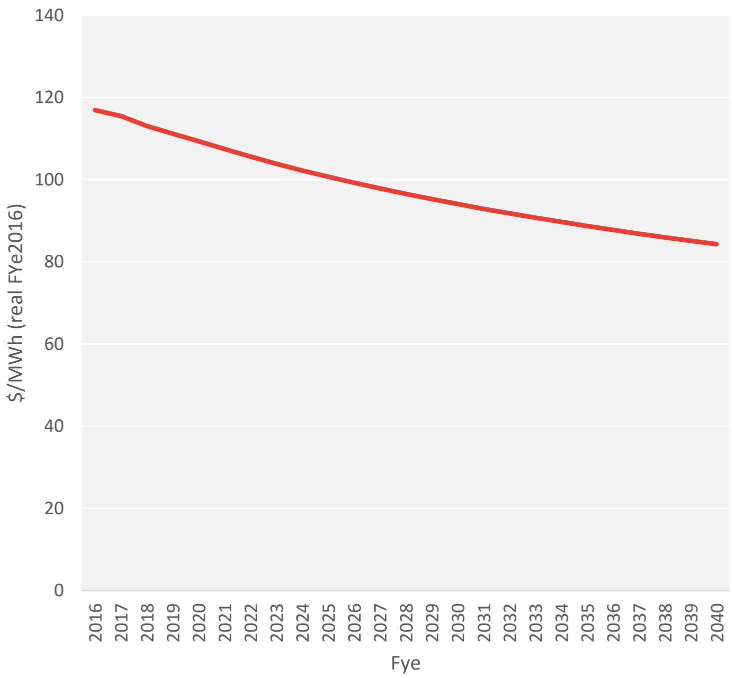
Source: Frontier Economics

Figure 12 shows our estimated LRMC of new utility-scale solar PV over time. This is currently estimated at around $117/MWh in FYe2016 based on assumed capex of $2035/kW, capacity factor of 22%[13], WACC of 8.51% and O&M costs of ~$20/MWh. These costs decline over time, however projected investment in new solar may be limited by the following factors:

- Most new investment to meet the current LRET is required within the next 5/6 years, when solar is still relatively more expensive than wind (without other subsidies such as ARENA funding);
- Although the output profile of solar PV (high in summer/midday) is relatively valuable now, this value may decline over time due to growth in rooftop solar PV, which is already shifting peak demand (and prices) to later in the afternoon/evening, and reducing summer/midday peak prices.
  - Beyond ~2024, utility scale PV is competing with gas and rooftop PV (which does not face transmission costs)

13 This is based on ARENA data of proposed PV projects from March 2016, http://arena.gov.au/files/2016/03/ARENA-Large-scale-Solar-PV-Competitive-Round_EOI-Data-Output_March-2016.pdf and details of successful projects released in September 2016: https://arena.gov.au/media/historic-day-australian-solar-12-new-plants-get-support/.

Figure 12: Utility Solar PV ($/MWh, FYend $2016)



Source: Frontier Economics

2.6 State-based renewable schemes

Various states have implemented or announced additional renewable policies.

ACT

The ACT government conducted a tender to purchase 200MW of wind in Sep 2014 (round 1). A second tender was held for a further 200MW, with successful bidders announced in late 2015/early 16. The successful projects for a third tender (a further 200MW of wind) were announced in August 2016, for a total of **600MW**.

- These projects are based in VIC (100MW), SA (309MW) and NSW (91MW).
- Although these can create LGCs under the LRET, these projects are **additional** to the LRET (LGCs will be voluntarily surrendered, not contributing to meeting the target).

This scheme is legislated and operational.

VIC

In June 2016 the VIC government proposed a 25% renewable target by 2020 and 40% by 2025.[14] The proposed scheme will involve a series of tranched auctions (tenders) for new renewable energy capacity, similar to the ACT reverse auctions. Many details of the scheme are still under consultation, for example:

- Although the proposed targets are announced (25% by 2020, 40% by 2025), the relative mix of wind/large scale solar is not yet determined. The majority of auctions are proposed to be renewable energy technology neutral. Based on current technology costs, this would see wind as the dominant technology under the scheme. The Government intends to auction a proportion of capacity for large-scale solar projects. The split of technology types (once determined) should not affect the results for VIC GPG.
- Projects must be located in VIC. This contrasts with the ACT scheme where projects are typically located in other regions. The requirement for projects to be VIC based means that all of the increase in renewable output will occur within Victoria, reducing the need for generation from other fuels, or imports from other regions.
- The timing of auctions and the annual requirements for new build have not yet been determined, however the announced targets are expected to result in:
  - **1800MW** new VIC wind (or up to 20% solar) up to 2020. This amount is proposed to be **complementary** to the existing LRET, which means that LGCs created by these projects will be used to meet the target.
  - **3600MW** additional new VIC wind (or some solar) after 2020, which is proposed to be **additional** to the existing LRET (voluntarily surrendered).
  - The combined result is a further ~5400MW of new wind in VIC in total, though only 3600MW would be additional to what is expected to be delivered by the LRET.
  - This design is intended to avoid distorting the LRET: in the alternative, if the 1800MW of new projects before 2020 were to have their LGCs voluntarily surrendered under the LRET (not contributing to meeting the target) then this would require additional renewable projects (in other regions) to meet the LRET. Similarly, if the ~3600MW of new VIC wind after 2020 were to instead surrender LGCs to meet the LRET then this would most likely crowd out (reduce) new renewable investments that would otherwise occur in other regions.

This proposed scheme is an announced policy under consultation but not yet legislated. We assume that this proposed policy will proceed as announced in both

[14] http://earthresources.vic.gov.au/energy/sustainable-energy/victorias-renewable-energy-targets

of our scenarios. In the absence of annual targets, we assume that the new VIC build before 2020 is roughly in line with our modelling the national LRET, and the new build after 2020 reflects a broadly linear trend. Based on these assumptions, this results in an approximate increase in new VIC renewables (wind) of almost 15TWh from 2017 to 2025 compared with current levels, which more than offsets the loss of around 10TWh of output from Hazelwood by 2018.

QLD

The QLD government has proposed a target of 50% renewables by 2030.[15]

- This target is calculated differently and includes contributions from rooftop PV, and the existing LRET (whether located in Qld or not). This policy is still in consultation but early estimates are that it might lead to an additional 5500MW new grid scale renewables (not rooftop PV) from 2020-30 **above** the existing requirements of the LRET.

Given the earlier stage of development of this policy, and uncertainty around whether this will be additional to or complementary to the national LRET, we have not included this proposed policy in the modelling scenarios. The inclusion or otherwise of this policy is unlikely to make a material difference to Victoria GPG.

15 https://www.dews.qld.gov.au/electricity/solar/solar-future/expert-panel

3 LRET overview

The LRET provides a financial subsidy for electricity from renewable generators, such as wind and solar farms or hydro-electric power stations. The scheme sets a target for Large-scale Generation Certificates (LGCs). Eligible renewable generation creates one LGC for each MWh electricity produced. LGCs can be sold to liable parties (electricity retailers) who surrender them annually to the Clean Energy Regulator (scheme administrator) to comply with the scheme's annual targets. The revenue earned by the power station for the sale of LGCs is additional to that received for the sale of the electricity generated.

3.1 LRET target history

The Federal Renewable Energy Target (RET) was originally introduced in 2000 and set a target of 9.5 TWh from renewable sources by 2010.

In 2009 the target was increased to 45 TWh by 2020. This target included certificates from both large scale wind and small scale generation (including rooftop solar PV). This was intended to reflect around 20% of total projected demand by 2020.

In 2010, rooftop solar was eligible for a certificate multiplier – it earned five times the certificates of large scale renewable. In addition, all certificates were credited upon installation, recognising 15 years of future generation. At the same time, most States introduced Feed-in Tariffs as an additional support scheme for rooftop solar PV. This led to a significant surplus of renewable certificates from solar PV: 39 million certificates were created in 2010 compared with a target of 12.5 million.

In response, the scheme was split from the end of 2010 into a Large Scale Renewable Energy Target (LRET), with a target of 41TWh from 2021-2030, and a small scale renewable energy scheme (SRES) for rooftop PV, which has a fixed price but no certificate target. However, all of the surplus certificates created by solar PV in 2010 were retained as surplus credits eligible to meet the LRET.

In 2014/15 there was increasing pressure to reduce the LRET in response to lower than expected growth in energy demand. In June 2015 the LRET was reduced to 33TWh from 2020-2030.

The Federal Opposition (Labor) has announced a policy to target 50% renewable energy for 2030[16]. The mechanism for this was not announced.

16 https://cdn.australianlabor.com.au/documents/Climate_change_action_plan_policy_paper.pdf

3.2 Basic operation of the LRET and the merit order effect

Box 1 provides a high level overview of how the LRET works and can affect pool prices (and gas dispatch). In summary:

- The LRET is a quantity target for new renewables with tradeable certificates.
- The sale of certificates (LGCs) provides a subsidy to cover the higher cost of renewables over other generation.
- This encourages new supply in the market to meet renewable targets
- Where the renewable target grows faster than demand growth, this can lead to excess supply in the market and lower electricity prices. Low electricity prices are a signal of excess supply and that capacity is not needed, but the LRET provides a different price signal (subsidy).
- This effect can also lead to new renewables entry displacing gas from dispatching.

Box 1: Simple example of LRET operation and merit order effect

Fig 1: No LRET. Renewables are more expensive than thermal generation and don't enter the market. Pool prices are set by the intersection of demand and the price bids of thermal generation (P*, Q*). Where there is excess supply, average prices will tend toward the short-run marginal cost of coal plant. Where there is strong demand (supply shortage) average prices will tend toward the long-run marginal cost of new entrant coal or gas (providing a signal for new investment).

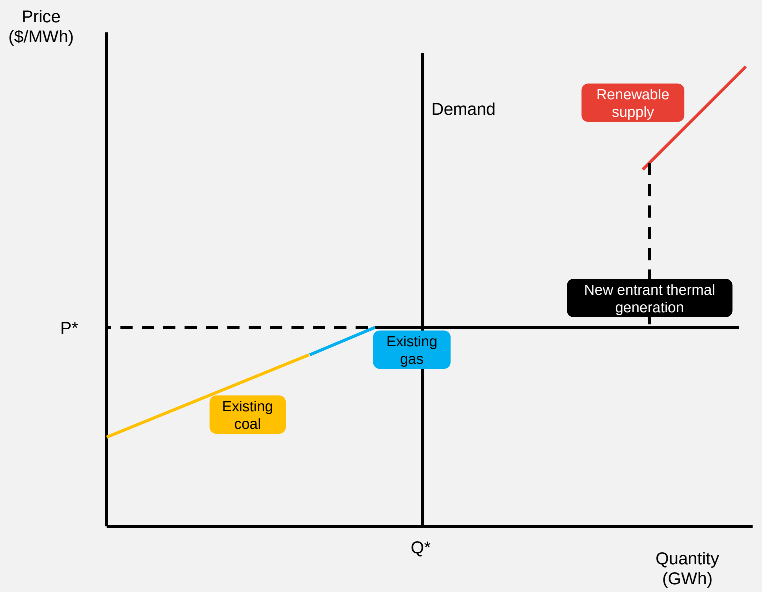


Fig 2: LRET with weak demand growth. A quantity target is set for renewable generation (Qr2). This requires a subsidy for renewables, reflecting the difference between electricity prices and their cost (Pr2 – P2). This cost is recovered via a levy on retail prices. The entry of new renewables in this case (with weak demand growth) shifts the supply curve to the

right (the top grey arrow shows the shift of the red renewable supply curve to the left, and the bottom grey arrow shows the shift of the thermal supply curve to the right), which lowers average pool prices from P* to P2. This is referred to as the **merit order effect**. In this case, increased wind output is likely to displace high costs gas output.

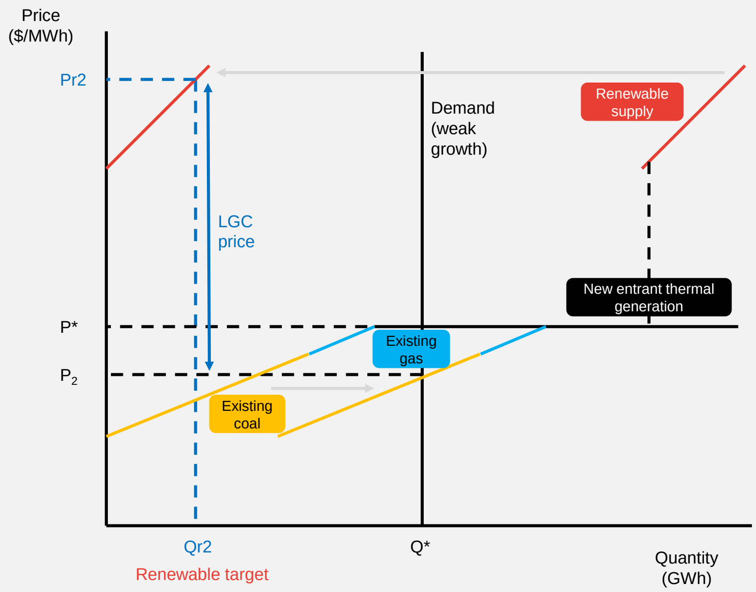
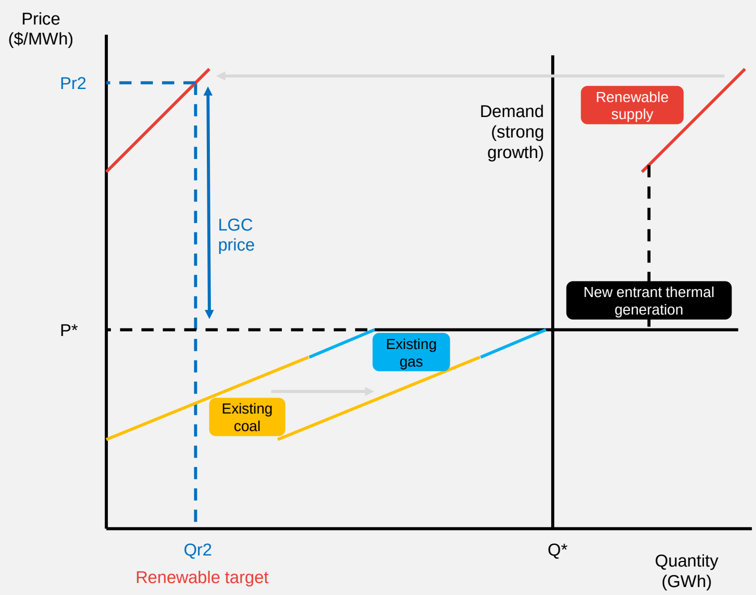


Fig 3: For the same renewable target where there is strong demand growth, or retirements of existing thermal, the entry of new renewables does not reduce pool prices. The extent of any merit order effect (suppression of pool prices) depends on whether growth in the renewables target exceeds growth in demand. Note also that this effect approaches a limit (floor) at the short-run cost of existing coal plant: further entry of new renewables will tend to encourage thermal retirements beyond this point rather than continued reductions in pool prices.



Tables and figures

4 Modelling results

This section presents the key results of Frontier's modelling.

4.1 Base Case: No carbon price

4.1.1 Output by fuel: Victoria

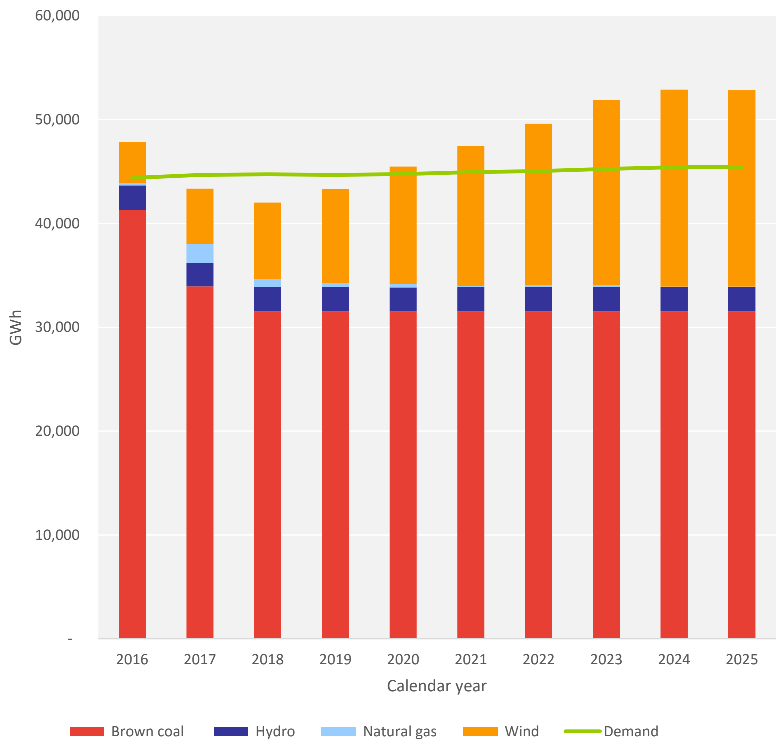
Figure 13 shows our forecast output mix for Victorian generation by fuel type in the **No Carbon Price** scenario. Victorian demand is shown in green: where output exceeds demand, Victoria is a net exporter of electricity, and conversely.

Key points include:

- In 2016, output is initially dominated by brown coal and, to a lesser extent hydro and wind, with very little gas output. Victoria is a net exporter of electricity.
- The closure of Hazelwood in March 2017 sees a drop in brown coal output of around 7.4TWh in 2017 (due to partial year closure) and 10TWh in 2018 (Table 4).
  - Initially, Victoria reverts from net exports to net imports in 2017-19, meaning that much of Hazelwood's output is replaced with increased generation from other regions. Reduced export/increased imports account for around 60% of the reduction in Hazelwood output in 2017 and 2018. The net reduction in total Victorian generation post-Hazelwood retirement is 4.5TWh (2017) and 5.8TWh (2018). This is reflected as the increase in non-Victorian generation in the final column of Table 4, where a positive amount means reduced Victorian exports/increased imports.
  - In 2017, the remainder of Hazelwood's output is replaced by a mix of increased Victorian wind (~20% of the Hazelwood reduction) and increased Victorian gas (~22%).
    - Wind increases from 3.9TWh to 5.3TWh in 2017, though further increases in wind output are limited only by constraints on the ability to physically build new wind plant. Gas increases from 0.2TWh to 1.8TWh in 2017.
  - In 2018, Victorian wind is projected to grow due to the rising LRET. In 2018, the increase in wind output takes up a larger share of the reduction in Hazelwood output (34%). This displaces some of the increase in Victorian gas that initially occurs in 2017. By 2018, the increase in Victorian gas output is only 6% of the reduction in Hazelwood dispatch.
  - This trend continues in 2019 and beyond: Victorian wind continue to grow to meet the LRET (and VRET), and this further displaces some of the

Victorian gas and the imports from other regions. By 2020 Victoria is once again a net exporter and by 2022 the increase in Victorian wind output (relative to 2016 levels) is greater than the loss of Hazelwood output.

Figure 13: Victorian output by fuel, No carbon price



Source: Frontier Economics

Table 4: How the loss of Hazelwood output is replaced (No carbon price)

Calendar Year	Reduction in Hazelwood output versus 2016	Increase in generation relative to 2016 levels (% of HZ reduction in output in brackets)		
		Victorian wind	Victorian gas	Non-Victorian generation
2017	7.4TWh	1.4TWh (19%)	1.6TWh (22%)	4.5TWh (60%)[1]
2018	9.8TWh	3.4TWh (34%)	0.5TWh (6%)	5.8TWh (60%)
2019	9.8TWh	5TWh (52%)	0.2TWh (2%)	4.5TWh (46%)
2020	9.8TWh	7.3TWh (75%)	0.1TWh (1%)	2.3TWh (24%)
2021	9.8TWh	9.5TWh (97%)	-0.1TWh (-1%)	0.4TWh (4%)
2022	9.8TWh	11.5TWh (118%)	0TWh (0%)	-1.8TWh (-18%)

1. Does not sum to 100% as hydro output falls marginally due to low storage levels

4.1.2 Gas output by generator: Victoria

Figure 14 shows the projected annual gas use (PJ/year) by generator in Victoria for the No Carbon Price scenario. In aggregate this reflects the light blue bars in Figure 13, expanded to show the division in gas use by generator. We also present forecast gas use on the Victorian Transmission System (VTS), which excludes output from the Bairnsdale and Mortlake power stations.

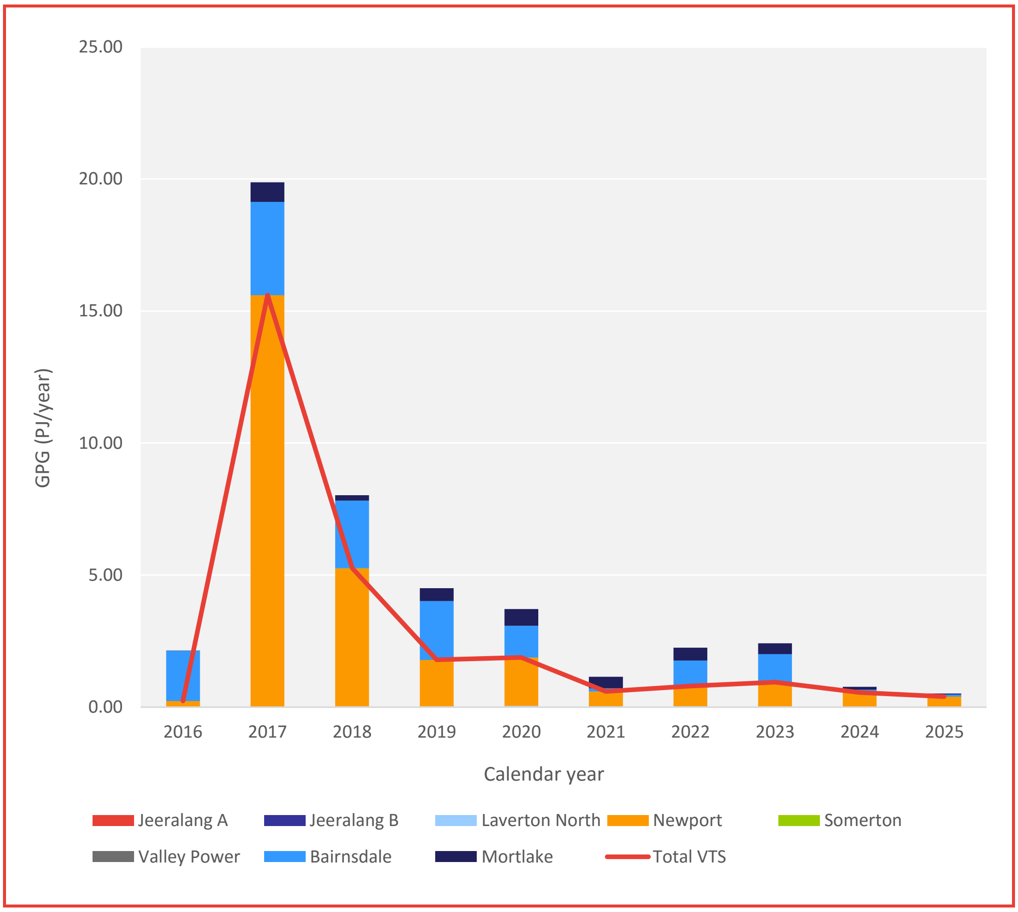
In aggregate there is a spike in gas generation in 2017 due to the closure of Hazelwood in March of that year, which is before sufficient wind can enter the market to fully replace Hazelwood's contribution to Victorian supply.

Aggregate gas use declines thereafter as wind enters the market to meet the LRET and VRET.

Individually, most of the projected output in 2017 and 2018 is from Newport and to a lesser extent Bairnsdale and Mortlake.

In recent years, Mortlake has provided more output than Newport, though we understand that this is largely due to lower historical gas prices. In our assumptions by generator (and consistent with other public forecasts), we project that it is more likely that Newport will dispatch more frequently than Mortlake, though the nature of cost-based modelling makes it difficult to accurately reflect output from peaking gas plant: even a very small difference in cost assumptions (including efficiency, fuel prices, and operating costs) will mean that one plant will invariably dispatch ahead of another, whereas in reality they may dispatch at similar levels. As such, our modelling may err on overstating Newport output at the expense of Mortlake.

Figure 14: Victorian GPG by generator, No Carbon price



Source: Frontier Economics

The data underlying this chart is presented in Table 5.

Table 5: GPG by Vic power station (No carbon price), PJ/year

Calendar Year	Jeeralang A	Jeeralang B	Laverton North	Newport	Somerton	Valley Power	Total VTS	Bairnsdale	Mortlake	Total VIC
2017	0.00	0.00	0.01	15.59	0.00	0.00	15.61	3.53	0.74	19.87
2018	0.00	0.00	0.02	5.23	0.00	0.01	5.27	2.56	0.21	8.03
2019	0.00	0.00	0.02	1.75	0.00	0.01	1.79	2.23	0.49	4.51
2020	0.00	0.00	0.04	1.83	0.00	0.01	1.88	1.19	0.64	3.71
2021	0.00	0.00	0.03	0.55	0.00	0.00	0.59	0.12	0.44	1.15
2022	0.00	0.00	0.03	0.76	0.00	0.01	0.80	0.97	0.49	2.25

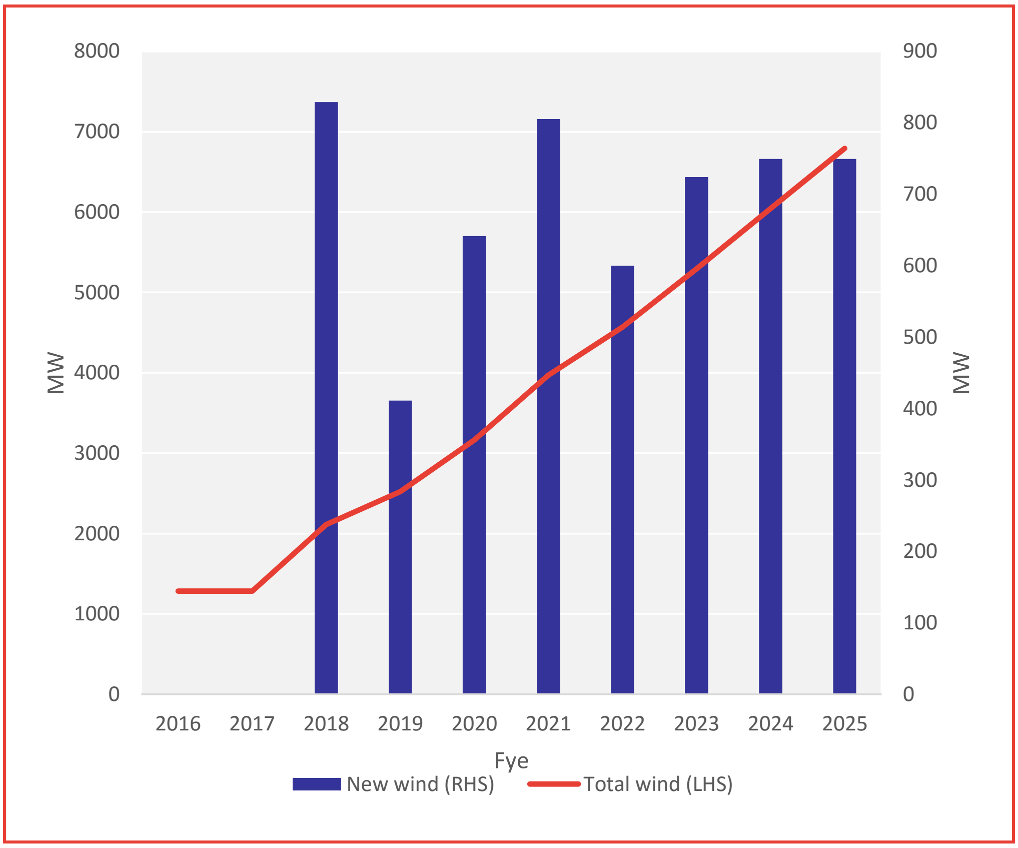
4.1.3 Investment

Figure 15 shows our forecast for total (LHS) and new annual investment (RHS) in wind in VIC. This investment is the same for both cases: new wind investment is driven by the LRET/VRET, which is the same in both scenarios.

We assume that no wind can be built in FYe2017, as policy uncertainty around the LRET meant an investment freeze over recent years that has contributed to high spot LGC prices. Now that this policy uncertainty is resolved, projects are under development and can commence operation by FYe2018. We assume that, on average, around 690MW of new wind can be constructed per year. This is partly a function of physical constraints and partly reflects the indicative proposed trajectory of the VRET.

Although the VRET is not specific on the relative split of wind and solar, we assume for this modelling that (on cost) this will be predominantly met with new wind. If the target prescribes a minimum share of solar then this would lead to higher overall investment in new renewables but similar output (due to the lower capacity factor of solar), which means no material change in gas use forecasts.

Figure 15: Total and new wind investment, VIC, both scenarios



Source: Frontier Economics

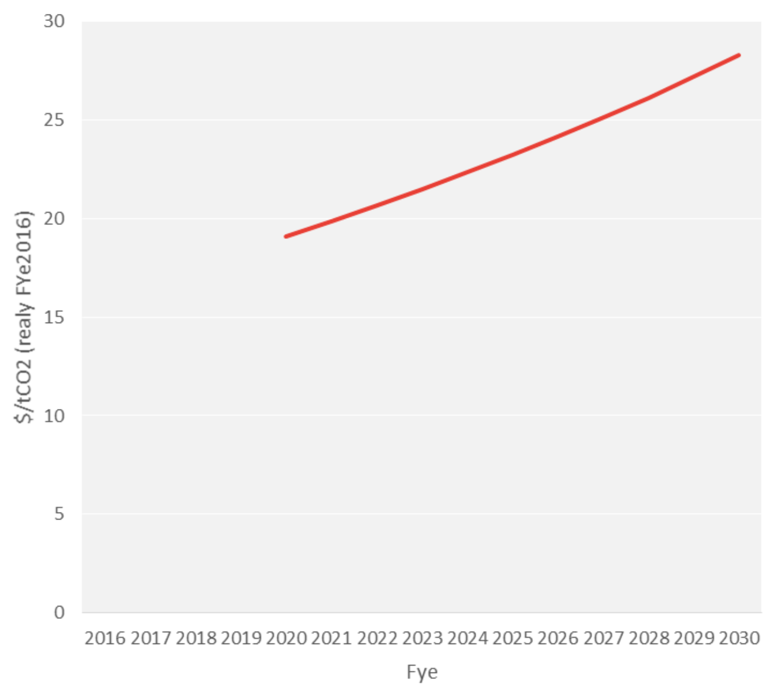
4.2 With carbon price scenario

4.2.1 Carbon price forecast

Figure 16 shows the projected carbon price for the With Carbon Price scenario. This is a model output and reflects the carbon price required to meet a sector target consistent with a 28PC reduction in 2005 emissions by 2030 without linkage with other sectors, or international trade of permits. To be clear, the carbon price in Figure 16 is an output from our modelling because we have included the sector emissions target as a constraint that must be met in our modelling. This is in contrast to an approach in which an assumed carbon price is included as a model input, and the sector emissions are an output of the modelling.

This is based on the assumptions above, including: AEMO's 2016 Medium demand, Frontier's gas price forecasts, the inclusion of Hazelwood and Liddell retirements as announced, and the implementation of the proposed VRET. All of these factors result in a relatively low carbon price as they ease the abatement task for the electricity sector. For this carbon price, and Frontier's gas price forecasts, this results in minimal change of output from Victorian brown coal plant (no further retirements are required before 2030), and minimal increase in Victorian gas-fired plant in the medium-term. This is driven by the strong growth in wind output in Vic that is driven by the LRET and VRET: over the longer term this growth in wind is more than enough to displace the loss of output from Hazelwood (while reducing emissions) without the need for increased output from VIC gas.

Figure 16: Forecast carbon price ($/tCO2e, FYe$2016)

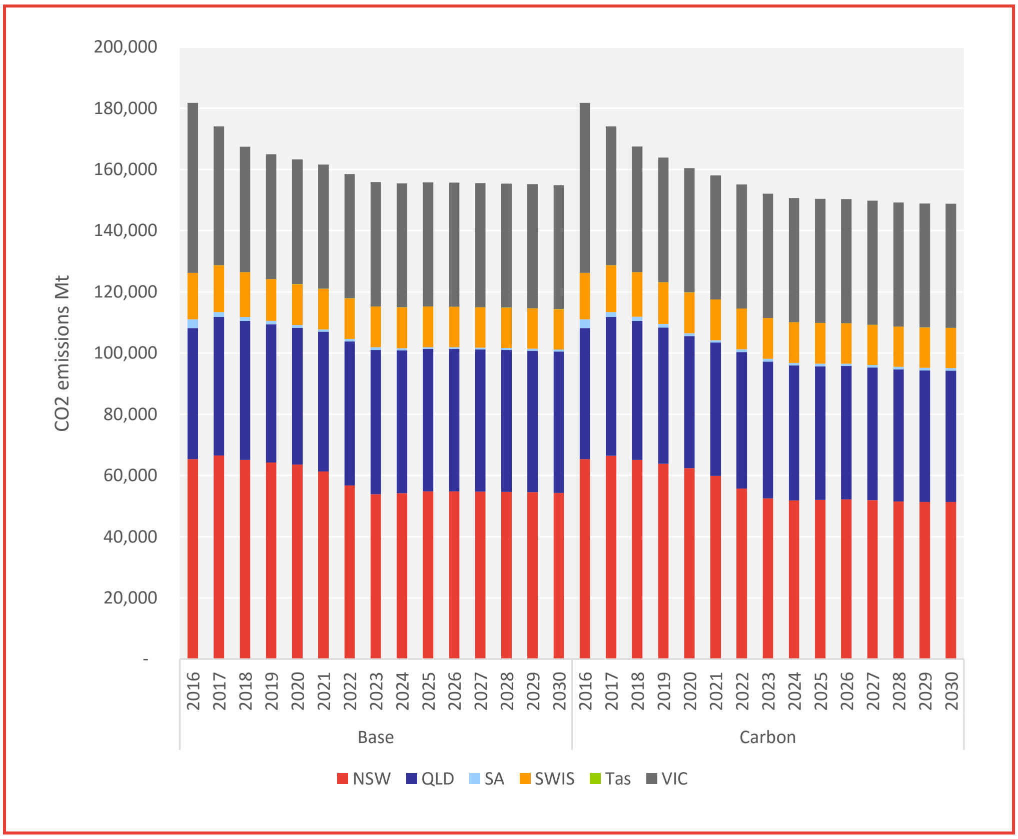


Source: Frontier Economics

Figure 17 shows forecast sector emissions by region in the Base Case (no carbon price) compared with the Carbon price case. Even in the Base Case (no carbon price) there is a sharp drop in sector emissions in VIC following the closure of Hazelwood (around 15Mt), and a further drop in NSW emissions due to the assumed closure of Liddell in 2022/3 (around 11Mt). Given these assumed closures as announced and the assumed introduction of the VRET as proposed, this means that the Base Case no carbon price emissions are relatively close to the assumed sector target for the Carbon Price case. Consequently, our carbon price scenario forecasts that the *additional* abatement to meet this target is mostly achieved through increased gas output in NSW and QLD. There is limited opportunity for Victorian gas to increase output given the large entry of supply from wind due to the VRET.

We do not include the proposed 50% QLD renewable target by 2030 in this modelling, but the effect of this would be to further reduce the Base Case emissions forecast. This would have a similar impact on QLD fuel mix/emissions as the VRET – the rise in QLD renewables output would reduce the need for increased QLD gas output. This would reduce the required carbon price to meet the sector target and reduce the need for, or likelihood of, increased gas output in QLD (and all regions) in the carbon price scenario.

Figure 17: Forecast emissions (NEM+SWIS)



Source: Frontier Economics

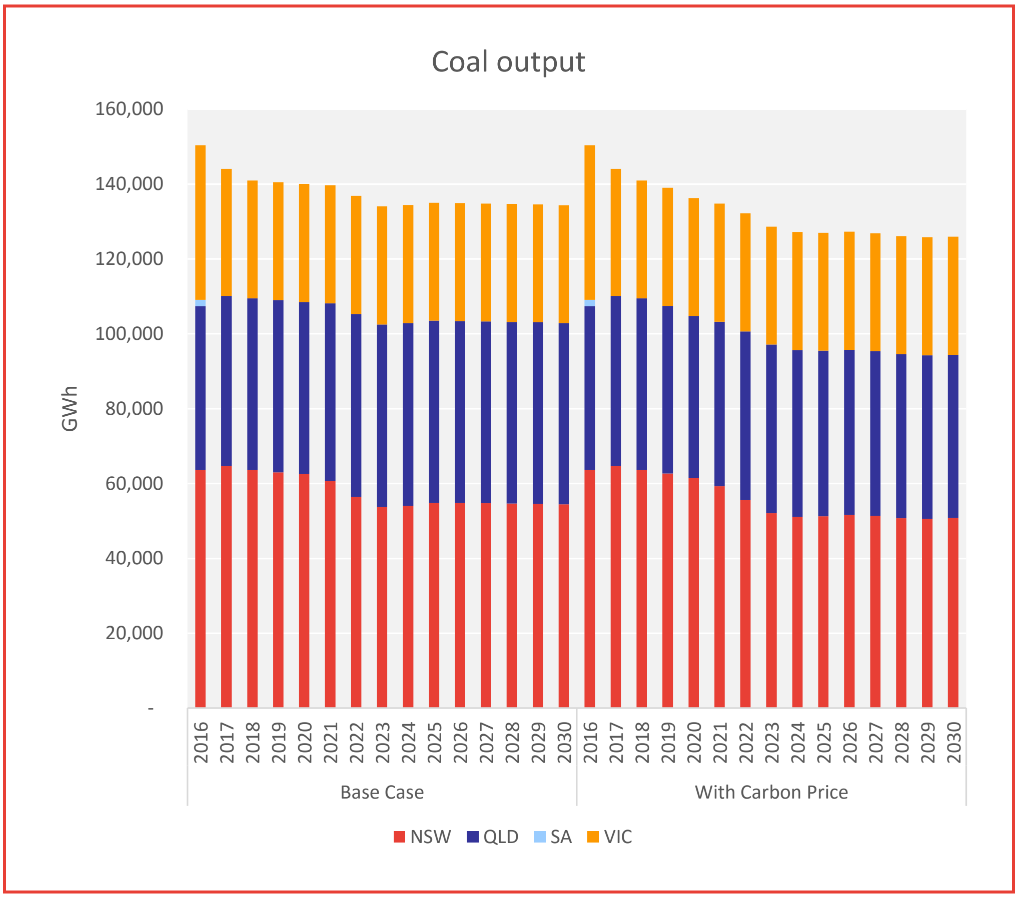
An alternative approach to forecasting a carbon price scheme would be to assume that if a carbon price (emissions trading) were introduced for the electricity sector, this might allow for import of international permits or export of Australian permits for use in other schemes. If unrestricted international linkage were a feature of any emissions trading scheme then it is likely that Australia (as a small, open economy) would be a price taker on international markets. In this instance we would model the sector with an assumed (international) carbon price as an input assumption, and the results sector emissions would be a model output.

Indicatively, the 2020 forward price for EUAs (certificates traded in the EU ETS) as at 16 December 2016 is 5EUR/tCO2[17], which is approximately $AUD7/tCO2. This is less than the carbon price forecast that we have modelled. This would result in less sector abatement and less gas output across the entire sector (all regions), though given the negligible differences between the Base Case and the With Carbon Price case, we wouldn't expect any material change in Vic GPG.

17 https://www.theice.com/products/197/EUA-Futures/data , accessed 16 December 2016.

Figure 18 shows the forecast coal output by NEM region, which largely explains the shape of the emissions forecasts above. In particular, the large drops in VIC (Hazelwood from 2017/18) and NSW (Liddell from 2022/3).

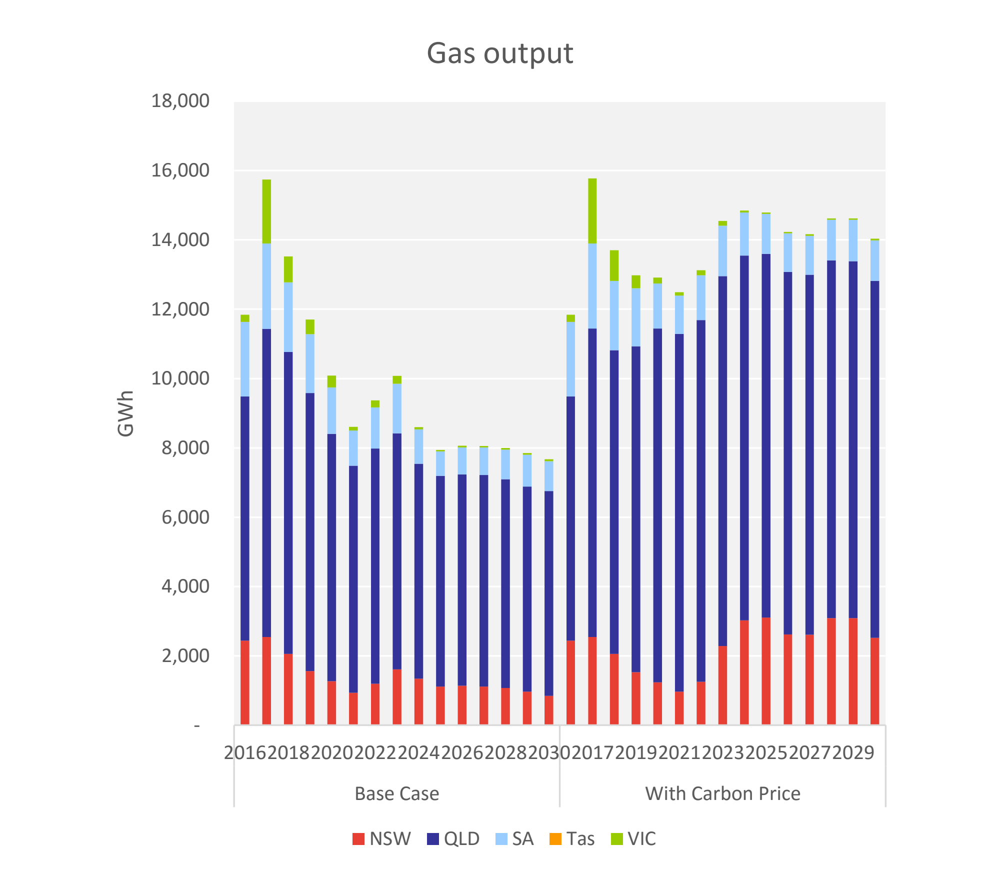
Figure 18: Coal output by NEM region, by case



Source: Frontier Economics

Figure 19 shows the forecast gas output by NEM region. As explained above, most of the increase in gas output to meet the sector emissions target is forecast to occur in QLD and to a lesser extent NSW. Despite the closure of Hazelwood, there is limited opportunity for increased VIC gas output due to rising wind output under LRET and VRET; there is some short term scope for increased output in 2017/18 before sufficient new wind can enter the market to replace the loss of output from Hazelwood.

Figure 19: Gas output by NEM region, by case



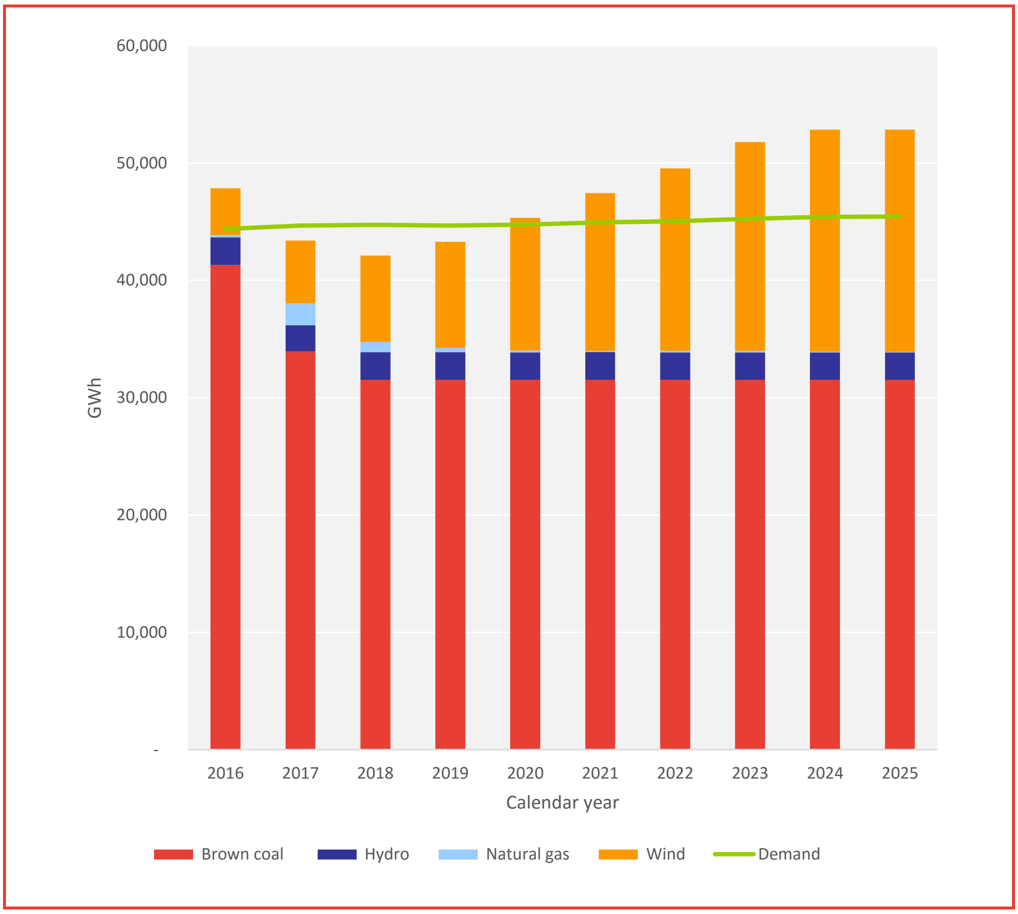
Source: Frontier Economics

4.2.2 Output by fuel: Victoria

Figure 20 shows our forecast output mix for Victorian generation by fuel type in the **With Carbon Price** scenario. The results are very similar to the No Carbon price scenario. The growth in wind output (which is driven by the LRET and VRET, not carbon pricing) is unchanged from the Base Case.

The relatively low carbon price (due to the closure of Hazelwood and rising LRET/VRET, which reduces the abatement task) means that there is minimal further change in the output of other Victorian brown coal during the period modelled. There are also only minor differences in Victorian gas/non-Victorian imports relative to the No Carbon Price scenario.

Figure 20: Victorian output by fuel, With Carbon price



Source: Frontier Economics

Table 6: How the loss of Hazelwood output is replaced (With carbon price)

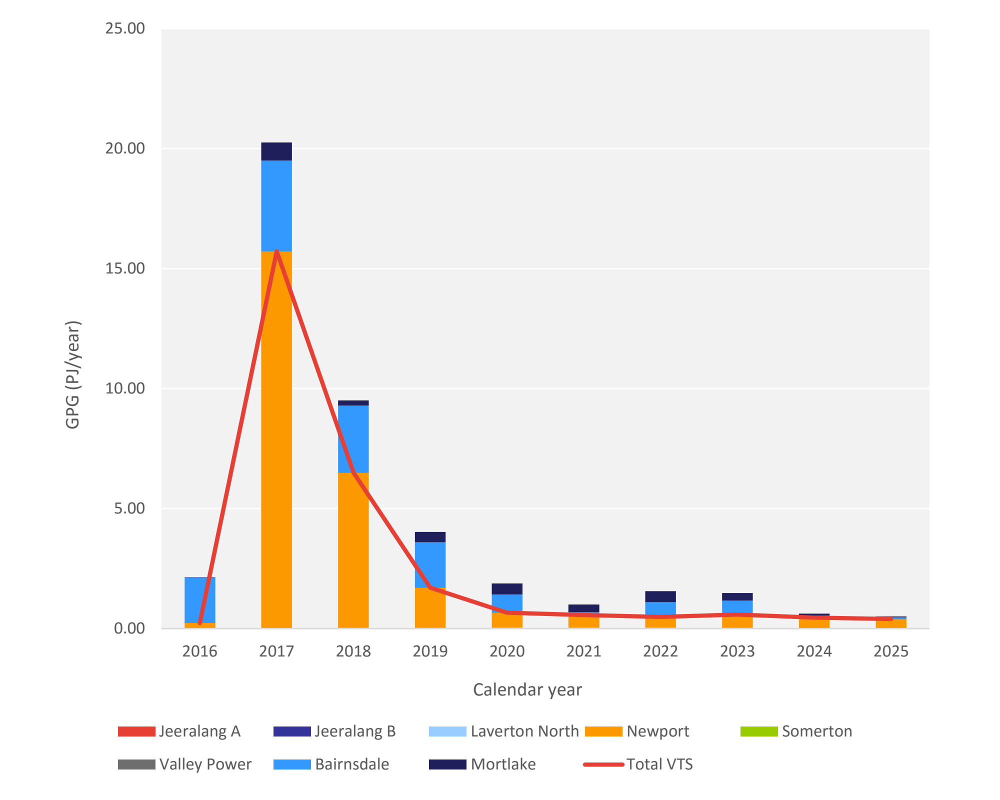
Calendar Year	Reduction in Hazelwood output versus 2016	Increase in generation relative to 2016 levels (% of HZ reduction in output in brackets)		
		Victorian wind	Victorian gas	Non-Victorian generation
2017	7.4TWh	1.4TWh (19%)	1.7TWh (23%)	4.5TWh (60%)[1]
2018	9.8TWh	3.4TWh (34%)	0.7TWh (7%)	5.7TWh (58%)
2019	9.8TWh	5TWh (52%)	0.2TWh (2%)	4.5TWh (46%)
2020	9.8TWh	7.3TWh (75%)	0TWh (0%)	2.5TWh (25%)
2021	9.8TWh	9.5TWh (97%)	-0.1TWh (-1%)	0.4TWh (4%)
2022	9.8TWh	11.5TWh (118%)	-0.1TWh (0%)	-1.7TWh (-17%)

1. Does not sum to 100% as hydro output falls marginally in 2017 due to low storage levels

4.2.3 Gas output by generator: Victoria

Figure 21 shows the projected annual gas use (PJ/year) by generator in Victoria for the **With Carbon Price** scenario. As explained above, these are largely the same as the **No Carbon Price** scenario: a combination of slow demand growth, rising LRET/VRET and the retirements of Hazelwood and Liddell results in a relatively low carbon price and very little additional fuel switching in Vic. The above factors already mean a considerable transition from brown coal to wind is forecast over the next 8 years.

Figure 21: Victorian GPG by generator, With Carbon price



Source: Frontier Economics

The data underlying this chart is presented in Table 7.

Table 7: GPG by Vic power station (With carbon price), PJ/year

Calendar Year	Jeeralang A	Jeeralang B	Laverton North	Newport	Somerton	Valley Power	Total VTS	Bairnsdale	Mortlake	Total VIC
2017	0.00	0.00	0.01	15.70	0.00	0.00	15.72	3.79	0.75	20.26
2018	0.00	0.00	0.02	6.46	0.00	0.01	6.50	2.80	0.21	9.50
2019	0.00	0.00	0.02	1.67	0.00	0.01	1.70	1.89	0.43	4.03
2020	0.00	0.00	0.03	0.62	0.00	0.00	0.66	0.76	0.46	1.88
2021	0.00	0.00	0.03	0.53	0.00	0.00	0.57	0.11	0.33	1.00
2022	0.00	0.00	0.03	0.45	0.00	0.01	0.49	0.62	0.45	1.55

Appendix 1: Gas prices for power stations

This section provides an overview of the methodology that we have adopted for estimating the marginal cost of gas supplied to a power station, and sets out our forecasts of gas prices.

Methodology

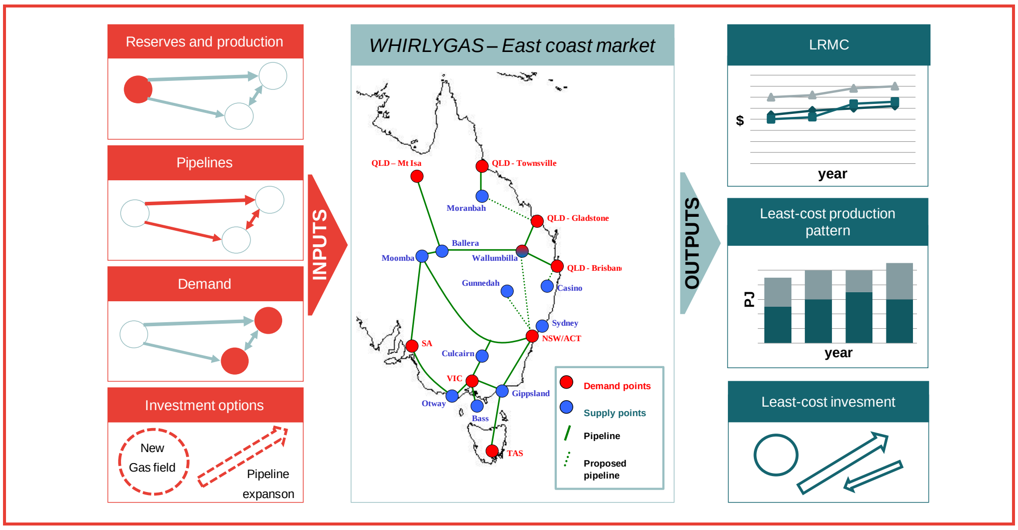
We estimate the cost of gas supplied to gas-fired power stations based on the marginal opportunity cost of gas.

When estimating the marginal opportunity cost of coal, we can do so on a region by region basis, because there is no substantial interconnection between coal supply regions. However, the same is not true of gas: gas regions in eastern Australia are now interconnected through a network of gas transmission pipelines, so that estimating the marginal opportunity cost of gas requires a model that can account for this interconnection. We use our gas market model – *WHIRLYGAS* – for this purpose.

Overview of WHIRLYGAS

WHIRLYGAS is a mixed integer linear programming model used to optimise investment and production decisions in gas markets. The model calculates the least cost mix of existing and new infrastructure to meet gas demand. *WHIRLYGAS* also simultaneously optimises total production and transport costs in gas markets and estimates the LRMC of each demand region in the gas market. A visual summary of the model is provided in Figure 22.

Figure 22: *WHIRLYGAS* overview



WHIRLYGAS is configured to represent the physical gas infrastructure in eastern Australia including all existing gas reserves, all existing production plant, all existing transmission pipelines and new plant and pipeline investment options. *WHIRLYGAS* is also provided with the relevant fixed and variable costs associated with each piece of physical infrastructure.

WHIRLYGAS seeks to minimise the total cost – both fixed and variable costs – of supplying forecast gas demand for eastern Australia's major demand regions. This optimisation is carried out subject to a number of constraints that reflect the physical structure and the market structure of the east coast gas market. These include constraints that ensure that the physical representation of the gas supply market is maintained in the model, constraints that ensure that supply must meet demand at all times (or a cost equal to the price cap for unserved gas demand is incurred), and constraints that ensure that the modelled plant and pipeline infrastructure must meet the specified reserve capacity margin.

WHIRLYGAS essentially chooses from an array of supply options over time, ensuring that the choice of these options is least-cost. In order to satisfy an increase in demand over the forecast period and avoid paying for unserved gas demand, *WHIRLYGAS* may invest in new plant and pipeline options. *WHIRLYGAS* may also shut-down existing gas fields and production plant where gas reserves become exhausted, or where they become more expensive than new investment options.

After generating the least cost array of investment options, the model is able to forecast gas production rates and pipeline flow rates, and to provide an estimate of the LRMC of satisfying demand in each demand region in each forecast year. The gas production rates and pipeline flow rates are determined by the least-cost combination of plant and pipeline utilisation that satisfies forecast demand. The LRMC is determined by the levelised cost of the plant and pipelines utilised in meeting a marginal increase in demand at each major demand region. The LRMC is also determined with regard to the scarcity of gas since, for each forecast year, the model considers the trade-offs from consuming gas that is produced from finite gas reserves in that year, as opposed to consuming the gas in other forecast years and in other demand regions (including as LNG exports).

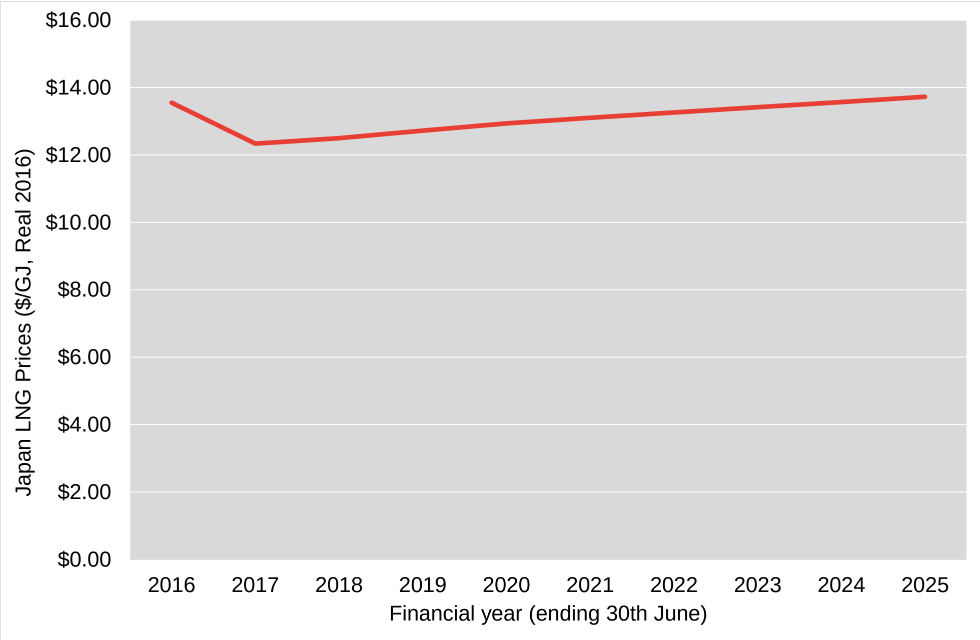
Opportunity costs in WHIRLYGAS

The reason that opportunity cost is relevant to assessing the cost to gas producers of supplying gas to gas-fired generators is because the producers may well be foregoing alternative markets for that gas. For instance, a gas producer that has access to the export market may well be foregoing the export price of gas (less any export-related costs). In this case, the netback price may be relevant to the opportunity cost of supplying gas to a gas-fired generator.

The **first step** in calculating the net-back price of gas is a forecast of the export price of LNG. It is this export price that determines the revenue that an LNG exporter will earn by exporting gas.

The export price that we have used to calculate the net-back price of gas is from quarterly forecasts released by the World Bank.[18] The World Bank provides forecasts of the Japanese LNG price out to 2025. These prices, which are in USD/mmbtu, are converted to AUD/GJ based on forecast nominal exchange rate discussed above. This results in the export prices shown in Figure 23.

Figure 23: Japan LNG prices ($2015/16)



Source: World Bank, Commodity Price Forecast, January 2016.

The **second step** for calculating the net-back price of gas is an estimate of the costs that an LNG exporter will avoid if it does not export LNG.

The avoided costs that need to be taken into account in calculating the net-back price of gas are:

- Shipping costs – estimates of the cost of shipping LNG from Gladstone to Japan are based on industry estimates.
- Liquefaction costs – estimates of the capital and operating costs associated with liquefaction of LNG are based on a Frontier Economics database of these costs.

18 http://pubdocs.worldbank.org/pubdocs/publicdoc/2016/4/173911461677539927/CMO-April-2016-Historical-Forecasts.pdf

- Pipeline costs – estimates of the capital and operating costs associated with transmission pipelines are based on the same Frontier Economics database of pipeline costs.
- The costs of managing exchange rate risk – these costs are based on industry estimates.

The **third step** in calculating the net-back price of gas is to adjust for the gas used in liquefaction. This use of gas in liquefaction means that there is a difference in the quantity of gas that can be supplied to the export market and the quantity of gas that can be supplied to the domestic market. Specifically, the use of gas in the liquefaction process means that exporting gas as LNG results in a reduction in saleable quantities relative to supplying gas to the domestic market.

The **final step** in calculating the net-back price of gas is to adjust for the effect of the discount rate on any revenues earned as a result of exporting LNG. If it is the case that the opportunity to export gas as LNG does not arise for several years (for instance because an LNG plant is still under construction, a new LNG plant would need to be constructed, or a relevant shortage of gas supplies to an existing LNG plant does not arise for a number of years) then the potential revenue from exporting this gas as LNG needs to be discounted to account for the time value of money. If gas can be supplied to the domestic market sooner, the effect of this discounting can have a material impact on the effective net-back price of gas.

This discounting is accounted for within *WHIRLYGAS*. As discussed, the model can test whether it is indeed the case that there is sufficient capacity in all required export-related infrastructure to export additional gas as LNG. Where there is a scarcity of liquefaction capacity (as opposed to a shortage of gas reserves or gas production capacity) the opportunity cost for gas producers need not reflect the net-back price. However, where there is a relevant scarcity of gas reserves or gas production capacity to meet LNG exports, the timing of this scarcity is important for determining the effective net-back price of gas.

Model inputs

The key modelling inputs for *WHIRLYGAS* under this approach are:

- gas demand forecasts for each major gas demand region
- gas reserves in eastern Australia
- the relevant costs and technical parameters of existing and new production plant in eastern Australia
- the relevant costs and technical parameters of existing and new transmission pipelines in eastern Australia
- the price of LNG in the Asia-Pacific region.

Model outputs

The key modelling outputs for *WHIRLYGAS* under this approach are:

- forecasts of the LRMC of satisfying demand in each demand region
- forecasts of investment in new production plants in eastern Australia
- forecasts of investment in new transmission pipelines in eastern Australia
- forecasts of production rates for existing and new production plants
- forecasts of flow rates for existing and new transmission pipelines
- forecasts of remaining gas field reserves in eastern Australia.

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