Oakley Greenwood

Issues Affecting Demand and Supply for Gas on the Victorian Transmission System

APA | October, 2021

DISCLAIMER

This report was commissioned by APA to understand the factors that are likely to affect the supply / demand balance in the Victorian gas market over the period of their next Access Arrangement period, and more specifically, the impact that those factors could have on the Victorian Gas Transmission System (including peak demands, and required augmentations).

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DOCUMENT INFORMATION

Project	Issues Affecting Demand and Supply for Gas on the Victorian Transmission System
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Units of Measure, Abbreviations and Glossary

Table 1: Units of Measure and Abbreviations

Abbreviation	Unit of measure	Abbreviation	Expanded Name
EDD	Effective degree days	AA	Access Arrangement
PJ	Petajoules	AEMO	Australian Energy Market Operator
PJ/yr	Petajoules per year	DTS	Declared Transmission System
TJ	Terajoules	DWGM	Declared Wholesale Gas Market
		DLNG	Dandenong Liquified Natural Gas
TJ/yr	Terajoules per year	EGP	Eastern Gas Pipeline
		FID	Final Investment Decision
		GSOO	Gas Statement of Opportunities
		GTA	Gas transportation agreement
		IASR	AEMO's Inputs, Assumptions and Scenarios Report
		MSP	Moomba to Sydney Pipeline
		NEM	National Electricity Market
		PKGT	Port Kembla Gas Terminal
		POE	Probability of Exceedance
		SWQP	South West Queensland Pipeline
		SWP	South West Pipeline
		VGPR	Victorian Gas Planning Report
		VNI	Victorian Northern Interconnect
		VTS	Victorian Transmission System
		WORM	Western Outer Ring Main

Table 2: Glossary

Term	Definition
1-in-20 peak day	The 1-in-20 peak day demand projection (for severe weather conditions) has a 5% probability of exceedance (POE). This is expected, on average, to be exceeded once in 20 years. Also known as the 95% peak day.
augmentation	The process of upgrading the capacity of a transmission (or a distribution) pipeline.
Culcairn	The point where the gas transmission network in Victoria interconnects with New South Wales.
DTS	AEMO defines the DTS as: "*the principal gas transmission pipeline system identified under the National Gas (Victoria) Act, including augmentations to that system. Owned by APA Group and operated by AEMO, the DTS serves Gippsland, Melbourne, Central and Northern Victoria, Albury, the Murray Valley region, and Geelong, and extends to Port Campbell*'.

Declared Wholesale Gas Market (DWGM or market)	AEMO defines the DWGM as: "*The market administered by AEMO under Part 19 of the NGR for the injection of gas into, and the withdrawal of gas from, the DTS and the balancing of gas flows in or through the DTS*".
Eastern Gas Pipeline	The east coast pipeline from Longford to Sydney.
Effective Degree Day	AEMO defines an EDD as: "*A measure of coldness that includes temperature, sunshine hours, wind chill and seasonality. The higher the number, the colder it appears to be and the more energy that will be used for area heating purposes. The Effective Degree Day (EDD) is used to model the daily gas demand-weather relationship*".
liquefied natural gas	Natural gas that has been converted to liquid for ease of storage or transport. The Melbourne liquefied natural gas (LNG) storage facility is located at Dandenong.
injection	The physical injection of gas into the transmission system.
Iona Underground Gas Storage (UGS)	The Iona UGS is located in the Port Campbell region. It is a storage facility which reinjects gas into depleted gas reservoirs, for withdrawal at a later date.
peak day	The day of highest system demand (gas).
petajoule (PJ)	1PJ = 1000TJ = 1000000GJ
South West Pipeline	The 500 mm pipeline from Lara (Geelong) to Iona.
system withdrawal zone	Part of the gas Declared Transmission System (gas DTS) that contains one or more system withdrawal points and in respect of which AEMO has determined that a single withdrawal nomination or a single withdrawal increment/decrement offer must be made.

Executive Summary

Background

APA is preparing for its upcoming Victorian Transmission System Access Arrangement (AA), due to be lodged by 1 December 2021.

APA would normally use AEMO's Gas Statement of Opportunities (GSOO) and Victorian Gas Planning Report (VGPR) as the basis for its load forecasts (that are an important element of its AA), however, according to the Terms of Reference we were engaged under, APA considers there to be three events affecting the AEMO's forecasts this time around:

- There have been a number of significant announcements and events since the GSOO/VGPR were published. Notably, APA's planned expansion of the East Coast Grid, Origin's contemporaneous supply contract with APLNG, and Esso and Qenos curtailing consumption in Altona.
- There are a number of proposed supply projects to bring gas into Victoria from the west of Melbourne. Any one of the proposed projects could trigger significant investment in the South West Pipeline (SWP) – however none have made it to Financial Investment Decision (FID) yet, nor are they expected to prior to APA submitting its AA to the AER; and
- AEMO's longer term gas demand forecast is (broadly) flat going out to 2040, suggesting no load reduction in response to the myriad of carbon reduction initiatives being contemplated or implemented throughout the economy.

Objective

APA commissioned Oakley Greenwood (OGW) to understand the factors that are likely to affect the supply / demand balance in the Victorian gas market over the period of their next AA period, and more specifically, the broad impact that those factors could have on the Victorian Gas Transmission System (including peak demands, and required augmentations).

As an Addendum to this report, APA asked OGW to undertake more detailed modelling of the potential impact these factors would have on Victoria's gas demands and peak demands, at the 6 system withdrawal zones of Ballarat, Geelong, Gippsland, Melbourne, Northern and Western.

The impact of the Altona refinery's closure and Qenos' reduced production

In February, 2021, Exxon Mobil announced they were closing their Altona refinery and converting it to an import terminal. This has a direct impact on gas demand, and moreover, it has a cascading effect on the consumption of gas by other consumers, in particular Qenos, the polyethylene and polymer producer, who announced that it will also close two of its production units (~50% of its plant) at its Altona plant.

To estimate the impact that their change in circumstances might have on both average and peak demand, we adopted the following methodology:

- **Reduction in Daily Average Demand**: Average consumption over the previous 3 years * estimated percentage change in reduction (100% for the Altona Refinery; 50% for Qenos[1])

[1] *Qenos reconfigures Altona manufacturing facilities*, Media Release, 19 May 2021 ("*The planned changes, which come into effect later this year, will involve the closure and mothballing of one of Qenos' two Altona ethylene units as well as one of the two polyethylene plants*")

- **Reduction in Coincident Peak Demand**: Average consumption over the previous 3 years on days when the Declared Wholesale Gas Market (DWGM) peaked * estimated percentage change in reduction (as per above).

The following table summarises the results.

Table 3: Impact on Demand

Key Issue	Peak Demand	Annual and Daily Average
Altona Refinery load reduction	Peak (TJ/day): 4.74	Daily Average (TJ): 3.76 * 100% reduction (closure of refinery) Annual (TJ): 1372 reduction
Qenos load reduction	Peak (TJ/day): 2.5TJ	Historical daily average of 5TJ/day * 50% = 2.5TJ/ay Annual (TJ) = 912TJ
TOTAL	**Peak (TJ/day) = 7.24**	**Annual (TJ) = 2280**

The SWQP/MSP upgrade has been committed

APA has recently announced that it has reached FID to commence the expansion by 25% of transportation capacity on its East Coast Grid, linking Queensland with southern markets. APA also announced a significant new East Coast Grid gas transportation agreement (GTA) with Origin Energy.

The estimated impact of this augmentation is that it will allow up to an extra 100TJ/day to flow into Sydney on peak demand days, with a consequent impact on the potential flows into Melbourne, subject to transmission pipeline capacity being available. That is, more southern gas will be available to supply Victoria, rather than get exported into NSW. This is based on the 25% increase in current capacity of ~ 400TJ/day[2] of the South West Queensland Pipeline (SWQP).

The policy environment surrounding gas supply and demand has changed

Victoria's Climate Change Act 2017 sets a target of net-zero emissions by 2050. More broadly, as part of Victoria's Climate Change Strategy, the State Government has set targets to reduce the State's greenhouse gas emissions from 2005 levels by 28-33% by 2025 and 45-50% by 2030.

The Victorian Government is on record as investigating pathways to decarbonise its gas network and it explicitly states in its *Victorian Gas Substitution Roadmap Consultation Paper* [3] that it is undertaking a *Deep Dive* in this regard.

Whilst AEMO's 2021 GSOO Central Case did not consider a scenario with greater electrification of residential heating (or other heating alternatives to gas) to drive down Victoria's maximum daily demand for gas, AEMO's *Inputs, Assumptions and Scenarios Report* (IASP), which was published in July 2021, 4 months after the GSOO, did. In particular, it details how AEMO *"will model the future in its forecasting and planning publications for the rest of 2021 and into 2022.*

Any move to decarbonise Victoria's gas grid, will, everything else being equal:

2 https://www.aemc.gov.au/energy-rules/national-gas-rules/gas-scheme-register/qld-south-west-queensland-pipeline; aligns with Figure 24, *2021, Gas Statement of Opportunities*, page 48

3 Victorian Government, *Help Build Victoria's Gas Substitution Roadmap*, Consultation Paper, pg 6

- Lead to a significant amount of gas load being electrified, which, if AEMO's IASR assumptions were adopted, would lead to nearly half the current gas heating load being electrified by the mid-2030s; and / or
- Lead to significant amounts of renewable gases entering the system, which[4]:
  - If they are hydrogen, might be at a distributed (distribution level) scale, avoiding APA's transmission network[5] but providing peak demand support (i.e., they would operate in a manner that would reduce peak demands placed on APA's transmission network);
  - If they are biomethane or synthetic renewable methane, may not necessarily be in locations that would utilise the existing transmission network (nor might they be of a scale that would necessitate connection at transmission level); and
  - Hydrogen and synthetic methane production will also add demand to the Victorian electricity system in the form of the demand for additional renewable electricity production.

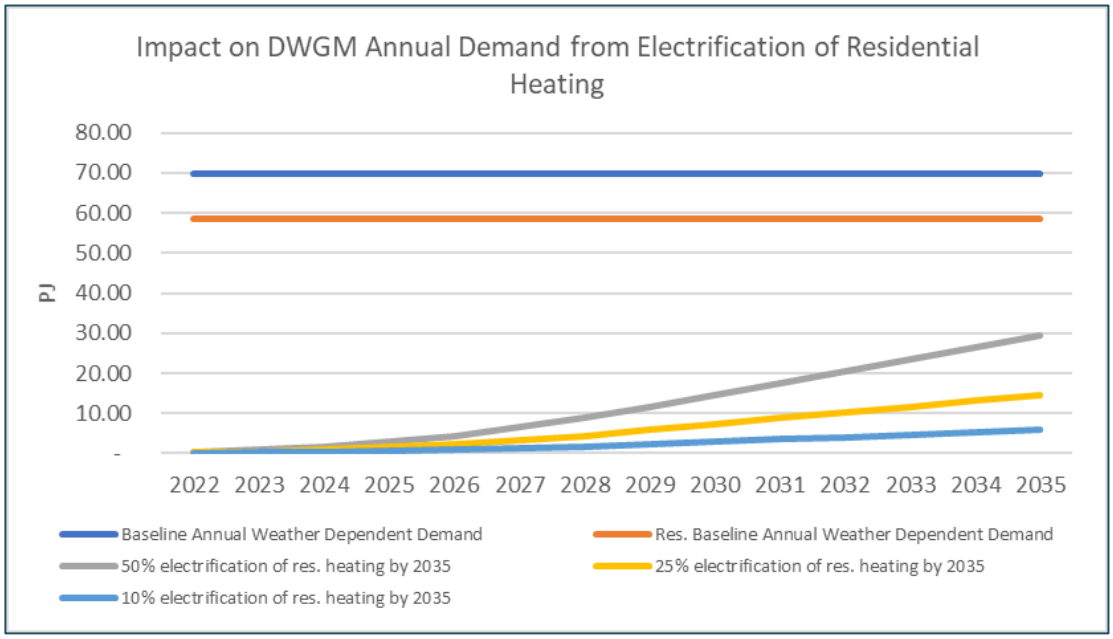
The following figures highlight the:

- Potential impact on annual demand of electrification of residential heating; and
- Potential impact on peak day demand of electrification of residential heating.

4 For the avoidance of doubt, in our opinion, there are currently a number of impediments in the Rules and Law to the blending of hydrogen into natural gas networks, as well as to the connection of renewable gas facilities at a distribution network level. For example, the current definition of 'natural gas' in our opinion, precludes the blending of hydrogen, and the Law and the Rules do not enable the registration of any gas production facilities that are connected to the distribution system. Notwithstanding this, it is our understanding that these impediments are known to policy makers at both a State and Federal Government level, and that there is a program of work to change the relevant parts of the Law and Rules that are considered to be an impediment. For example, Minister Taylor has recently stated that as part of the Energy National Cabinet Reform Committee, "*Ministers agreed on an expedited process to amend the National Gas Law, National Energy Retail Law and subordinate instruments so hydrogen blends, biomethane and other renewable methane gas blends are brought within the national energy regulatory framework*" (https://www.minister.industry.gov.au/ministers/taylor/media-releases/energy-national-cabinet-reform-committee-1)

5 The reason for this is that there is significantly more uncertainty as to the ability for hydrogen to be blended into gas transmission networks as compared to gas distribution networks, due to materials that the pipelines are generally constructed from and the pressures at which they operate.

Figure 1: Potential Impact on Annual Demand of Electrification of Residential Heating

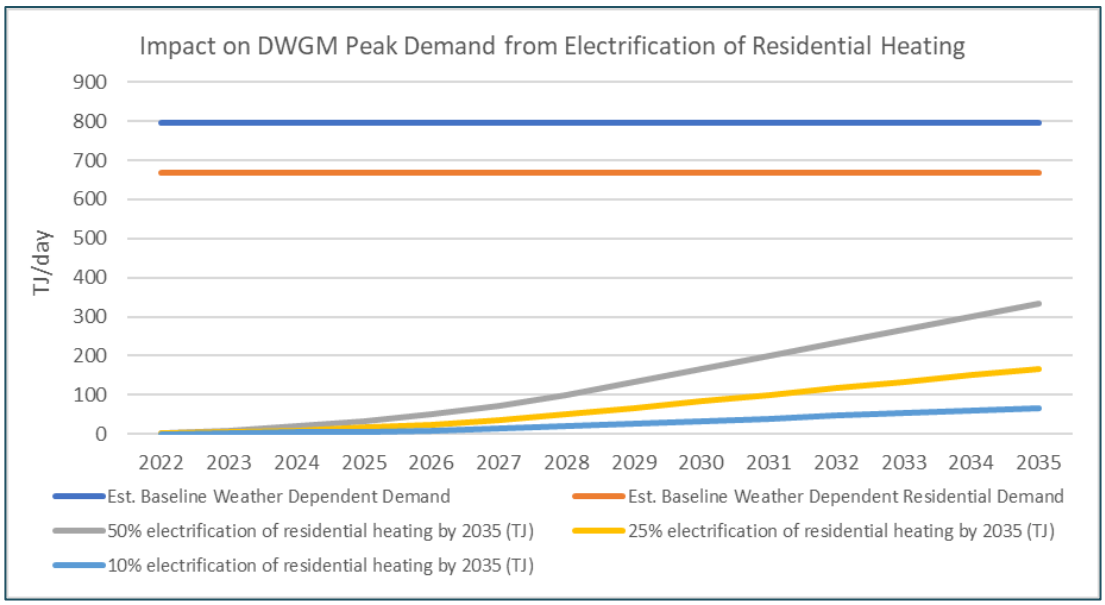


Notes: Based on OGW analysis - see body of report for details.

Figure 1 shows that, assuming that all weather dependent demand is driven by residential and commercial usage, then by 2035:

- 10% electrification of residential heating will result in a reduction of annual demand of around 6PJ;
- 25% electrification of residential heating will result in a reduction of annual demand of around 15PJ; and
- 50% electrification of residential heating will result in a reduction of annual demand of around 30PJ.

Figure 2: Potential Impact on Peak Day Demand of Electrification of Residential Heating



Notes: OGW analysis as per the approach outlined for Annual Demand, except that we assumed that total peak demand is 1250TJ/day.

Figure 2 shows that, assuming that all weather dependent demand is driven by residential and commercial usage, then by 2035:

- 10% electrification of residential heating will result in a reduction in peak demand of around 67TJ/day;
- 25% electrification of residential heating will result in a reduction of peak demand of around 167TJ/day; and
- 50% electrification of residential heating will result in a reduction of peak demand of around 335TJ/day.

The following table summarises the potential impact that the above factors could have on AEMO's forecast of peak demand (TJ/day) to 2030.

Table 4: Impact on VTS Peak Demand

Key Issue	Impact in 2025 (TJ/Day)	Impact in 2030 (TJ/Day)
Est. AEMO peak demand starting base	1250	1250
Increased Supply		
Increased supply resulting from expansion of the SWQP/MSP	100	100
Increased supply from Renewable Gases[6]	9.15	24.42
Reduced Demand		
Reduced consumption from Altona Refinery and Qenos	(7.24)	(7.24)
Reduced peak day consumption due to electrification		
High (50%)	*(33.42)*	*(167.11)*
Medium (25%)	*(16.71)*	*(83.55)*
Low (10%)	*(6.68)*	*(33.42)*
Net Change in Supply Adequacy		
TOTAL Change - Medium Elec	133.1	215.21
TOTAL Change - High Elec	149.81	298.76
Supply Adequacy		

6 This is discussed in detail in the body of the report.

Original GSOO Peak Day Supply Adequacy with PKGT (Southern Mkts)	+273	-308
Peak Day Supply Adequacy after adjustments (Southern Mkts)	**+406.1 to +422.81**	**-92.79 to -9.24**

NOTES: OGW analysis

Our analysis indicates that as a result of the Victorian Government's legislated commitment to Net Zero by 2050, and reflecting AEMO's IASR that under a Net Zero scenario, nearly half the current gas heating could be electrified by the mid-2030s (which broadly aligns with the Victorian Government's pathways analysis), there may only be a very small supply shortfall (-9.24TJ) on peak demand days in 2030. If electrification were to lag AEMO's assumption, with only 25% of customers having their heating loads electrified by 2035, the supply shortfall is larger, but still not insurmountable (at -92.79TJ) in 2030. Options for covering this supply shortfall are discussed in the next section.

The following table summarises the potential impact that the above factors could have on AEMO's forecast of annual demand (PJ) to 2030.

Table 5: Impact on VTS Annual Demand

Key Issue	Impact in 2025 (PJ)	Impact in 2030 (PJ)
	Increased Supply	
Increased supply resulting from expansion of the SWQP/MSP	None assumed for modelling	None assumed for modelling
Renewable Gases	1.34	3.73
	Reduced Demand	
Reduced consumption from Altona Refinery and Qenos	(2.28)	(2.28)
Reduced annual consumption due to electrification		
High (50%)	(2.93)	(14.64)
Medium (25%)	(1.46)	(7.32)
Low (10%)	(0.59)	(2.93)
	Net Change in Supply Adequacy	
TOTAL Change - Medium Elec	5.08	13.33
TOTAL Change - High Elec	6.55	20.65
	Supply Adequacy	
Original GSOO Supply Adequacy with PKGT (Southern Mkts)	No Shortfall	(65)

Annual Supply Adequacy after adjustments (Southern Mkts)	No Shortfall	-51.7 to -44.35

NOTES: OGW analysis

The above table:

- Reflects AEMO's underlying forecast that there is no annual gas supply gap in southern markets in 2025 under existing GSOO assumptions, therefore, the additional factors that we have discussed which would otherwise reduce gas loads would only contribute to a strengthening of this supply/demand position; however
- Even after incorporating the factors that we have discussed, there is still a supply shortfall in 2030 of 51.7PJ under the medium case, and 44.35 under our high case, assuming as given AEMO's other GSOO assumptions e.g., declining Longford supplies; LNG receipts; north / south transmission constraints for a substantial amount of the year.
- Whilst this shortfall is material, AEMO is forecasting no shortfall until 2029, beyond the AA period, and moreover, this figure is likely to be subject to significant uncertainty (e.g., the quantum of the reduction in Longford, noting the nature of any gas reservoir engineering analysis supporting this, and the inherent uncertainties that this entails).

Implications for New Transmission Investments

The future conditions affecting the domestic gas market are inherently uncertain – more so now than possibly at any time in its recent history. This uncertainty increases the value of flexible supply and infrastructure options to meet projected seasonal supply gaps, or put another way, it increases the risk associated with making long-term, large scale investments, in the face of this uncertainty.

Conceptually, a 'real options' analytical framework is ideally suited to undertake analysis in this type of uncertain environment. A 'real options' framework essentially represents a sophisticated probabilistic planning approach that can be used to assess the optimality of various options for balancing supply and demand. It explicitly recognises the trade-off between the value of flexibility and scale efficiency of supply and demand side options, having regard to the entire range of future events, and the ability of a modelled supply portfolio to be able to respond to that range of future events.

It explicitly quantifies the value of making decisions over time as would be the case in real life, rather than assuming perfect foresight. These decisions may involve higher costs in the short term, but lead to long term benefits.

Of the feasible options for alleviating any forecast supply / demand imbalance towards the end of APA's AA period, two involve transmission augmentations - augmenting the South West Pipeline and augmenting the Young-Culcairn link (NSW side of Interconnect) – whilst two others are more marginal, with one involving augmenting the Dandenong LNG facility and the other relying on price induced demand response.

Although we have not undertaken a detailed real options analysis for the purposes of this project, we are of the opinion that unless the Iona injection capacity into the SWP is fully contracted long-term (i.e., the market has already revealed its need for, and preference of, this solution, relative to other available solutions), increased compression on the Interconnect (i.e., NSW side) between Young and Culcairn at low marginal investment costs is the solution that the market may be more likely to rely upon, given the current uncertainty affecting the gas market, as this solution has the conceptual advantage:

- Of unlocking the full additional south bound (peak) capacity that is created by APA's expansion of the SWQP/MSP, noting that absent an investment such as this in additional north/south transmission capacity, AEMO's GSOO indicates that flows south bound on the EGP and Interconnect are at their capacity for a significant proportion of the year;
- Of potentially accommodating more, valuable, flexible seasonal "shaped" gas supplies, to be transported from the larger, more prospective gas outside of Victoria, to help cover monthly winter demand, not just extreme peaks; and
- Of being incremental and flexible, which means its funding is not reliant on the AER accepting the medium to long term forecast needs of the Victorian market, rather the market is able to respond (via contracting for solutions) closer to when the asset may in fact be needed, enabling more (and better) information as to the forecast supply / demand balance in Victoria to be revealed.

To our mind, there is also a case for policymakers to consider introducing a market mechanism that would allow demand side participation in the peak of winter to assist in managing the risks of small excess peak demand excursions. This would likely be a very low-cost (and flexible) solution to managing transitional issues and uncertainty, and mimics what has been occurring in the National Electricity Market (NEM).

Given the uncertainty as to what future (peak and annual) demands will be placed on the Victorian gas transmission network over the next 5-10 years (and beyond), and the fact that there appears to be a feasible alternative market-led solution to addressing peak day demand issues, we see little justification to support APA lodging a capital expenditure forecast that involves looping any part of the SWP to accommodate increased supply from either or both of the two LNG import facilities in Victoria, whilst also maintaining Iona's existing capacity to provide gas on peak days.

This is not to say that the market may not facilitate the development of these (FSRU) supply solutions over the period of APA's next AA; it may be that the market values their ability to alleviate any shortfall in annual or seasonal gas requirements in Victoria, whilst providing some increase in peak day support (relative to existing levels), in lieu of relying on Iona. If this were to occur, it would demonstrate that the market is in effect, seeking to reallocate how the existing SWP pipeline capacity is utilised.

Understanding the costs of these options will materially assist with future decisions.

Our opinion as to whether there is a case under the Rules for APA to request accelerated depreciation

OGW was asked to provide an opinion on this matter and prima facie, we think there is scope under the Rules for APA to seek the AER's consideration of an accelerated depreciation schedule for the assets that it uses to provide gas transmission (reference) services in Victoria. Such an outcome has regulatory precedence and is aligned to the Rules, as in our opinion, the Rules clearly provide a regulated gas business with the flexibility to propose changes to it forecast depreciation schedule to reflect, amongst other things, changes in the:

- Market for its reference services: and
- Economic life of the asset or group of assets that are used to provide its reference services.

As outlined earlier, we are of the opinion that there are a number of potential risks to the **market** for APA's current reference services, any of which could start to manifest in the short term, but with a higher probability of manifesting in the medium to long-term. These could affect the economic life of APA's assets.

1. Background and objective

1.1. Background

APA is preparing for its upcoming Victorian Transmission System Access Arrangement (AA), due to be lodged by 1 December 2021. The Victorian Transmission System (VTS) comprises approximately 1,992 kilometres of pipelines which transport gas from various injection points both to the East and West of Victoria, to load centres throughout Victoria. Almost all the natural gas consumed in Victoria is transported through the VTS.

As we understand it, APA would normally use AEMO's Gas Statement of Opportunities (GSOO) and Victorian Gas Planning Report (VGPR) as the basis for its load forecasts (that are an important element of its AA), however, according to the Terms of Reference we were engaged under, APA considers there to be three events affecting the AEMO's forecasts this time around:

- There have been a number of significant announcements and events since the GSOO/VGPR were published. Notably, APA's planned expansion of the East Coast Grid, Origin's contemporaneous supply contract with APLNG, and Esso and Qenos curtailing consumption in Altona.
- There are a number of proposed supply projects to bring gas into Victoria from the west of Melbourne. Any one of the proposed projects could trigger significant investment in the South West Pipeline (SWP) – however none have made it to Financial Investment Decision (FID) yet, nor are they expected to prior to APA submitting its AA to the AER; and
- AEMO's longer term gas demand forecast is (broadly) flat going out to 2040, suggesting no load reduction in response to the myriad of carbon reduction initiatives being contemplated or implemented throughout the economy.

In relation to the latter, Victoria's Climate Change Act 2017 sets a target of net-zero emissions by 2050. More broadly, as part of Victoria's Climate Change Strategy, the State Government has set targets to reduce the State's greenhouse gas emissions from 2005 levels by 28-33% by 2025 and 45-50% by 2030. The Department of Environment, Land, Water and Planning ('DELWP') is exploring pathways to support the decarbonisation of Victoria's gas networks in line with its Climate Change Strategy targets and longer-term legislated targets. These pathways include renewable gases such as renewable hydrogen, synthetic methane and biogas, as well as other pathways, including electrification and energy efficiency.

AEMO's *Inputs, Assumptions and Scenarios Report* (IASP), which was published in July 2021, 4 months after the GSOO, and which details how AEMO *"will model the future in its forecasting and planning publications for the rest of 2021 and into 2022"*, states that[7]:

> *The Net Zero 2050 scenario represents a future that delivers action towards an economy-wide net zero emissions objective by 2050 through technology advancements. This transition focuses on short-term activities in low emission technology research and development to enable deployment of commercially viable alternatives to emissions-intensive activities in the 2030s and 2040s. Stronger economy-wide decarbonisation, particularly industry electrification, occurs in later years as the 2050 deadline approaches.* ***Consumers are initially continue (SIC) to heat their homes in the same manner they do today, but by the mid-2030s nearly half the current gas heating has been electrified****, and in the final years of the horizon nearly all residential heating is electrified [emphasis added]*

7 AEMO, *2021 Inputs, Assumptions and Scenarios Report*, page 13

The highlighted section portends to the potential impact that AEMO expects could occur under a Net Zero 2050 scenario, noting Victoria's legislated target of net-zero emissions by 2050 and its clearly signalled intention to determine pathways to decarbonise Victoria's gas grid, with electrification front and centre.

1.2. Objective

This report was originally commissioned by APA to understand the factors that are likely to affect the supply / demand balance in the Victorian gas market over the period of their next AA period, and more specifically, the broad impact that those factors could have on the Victorian Gas Transmission System (including peak demands, and required augmentations).

As an Addendum to this report, APA asked OGW to undertake more detailed modelling of the potential impact these factors would have on Victoria's gas demands and peak demands, at the 6 system withdrawal zones of Ballarat, Geelong, Gippsland, Melbourne, Northern and Western.

OGW was also asked to consider the issue of accelerated depreciation.

1.3. Caveats

In order to complete this task, we considered, and in many cases relied on, publicly available information. We have taken much of this information on face value, and to the extent it is incorrect, the conclusions drawn from that information may also be incorrect.

For the avoidance of doubt, we did not seek any information directly from any party other than APA, nor did we seek information that directly related to any supply proponent, from any third party.

Given the complexity of the east coast gas supply/demand dynamic, the paucity of publicly available information in some cases (particularly in relation to the costs of undertaking certain upgrades, which we note, we were not asked to model in detail), and the long-term nature of the forecasts that we have been asked to develop, it has been necessary to make a number of assumptions and to draw conclusions from a number of different information sources.

The forecasts and conclusions contained in this report need to be considered in this light.

1.4. Structure of remaining sections of report

The remaining sections of this report are structured as follows:

- Section 2 summarises our understanding of AEMO's underlying forecast of the supply / demand balance in the Victorian Gas Market over the short to medium term;
- Section 3 outlines the factors that have changed since AEMO developed its most recent forecasts;
- Section 4 outlines the potential options for alleviating any forecast supply / demand imbalance towards the end of APA's AA period;
- Section 5 outlines the long-term impact on APA's business, and what that might mean for a number of its regulatory settings; and
- Section 6 summarises our conclusions.

Appendix A summarises our approach to developing, and forecasts of, peak and overall gas demand at the 6 system withdrawal zones of Ballarat, Geelong, Gippsland, Melbourne, Northern and Western.

2. AEMO's underlying forecast of supply / demand for the Victorian Gas Market

2.1. Objective of section

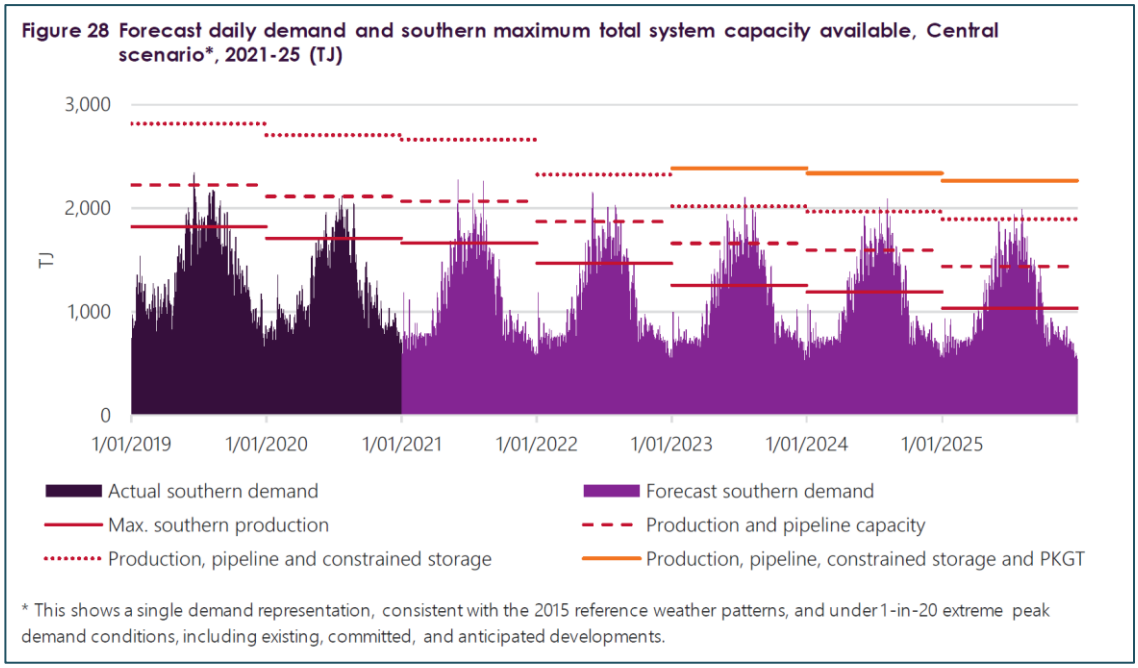
The objective of this section is to:

- Summarise the relevant information contained in AEMO's 2021 Gas Statement of Opportunities (GSOO) and its 2021 Victorian Gas Planning Report (VGPR), as it relates to forecast gas supply and demand in southern markets and Victoria; and
- Our summary of what that information, considered collectively, indicates might happen to Victoria's gas supply/demand balance over APA's AA period.

2.2. Gas Statement of Opportunities

The following figure presents AEMO's forecast daily demand and southern maximum total system capacity under their Central Scenario, out to 2025.

Figure 3: Forecast daily demand and southern maximum total system capacity available, Central scenario, 2021-25 (TJ)



Source: AEMO *2021, Gas Statement of Opportunities*, page 56

In the above figure, the:

- Solid red line shows the maximum available southern production, the dashed red line represents the additional maximum daily capacity available from South West Queensland Pipeline (SWQP);

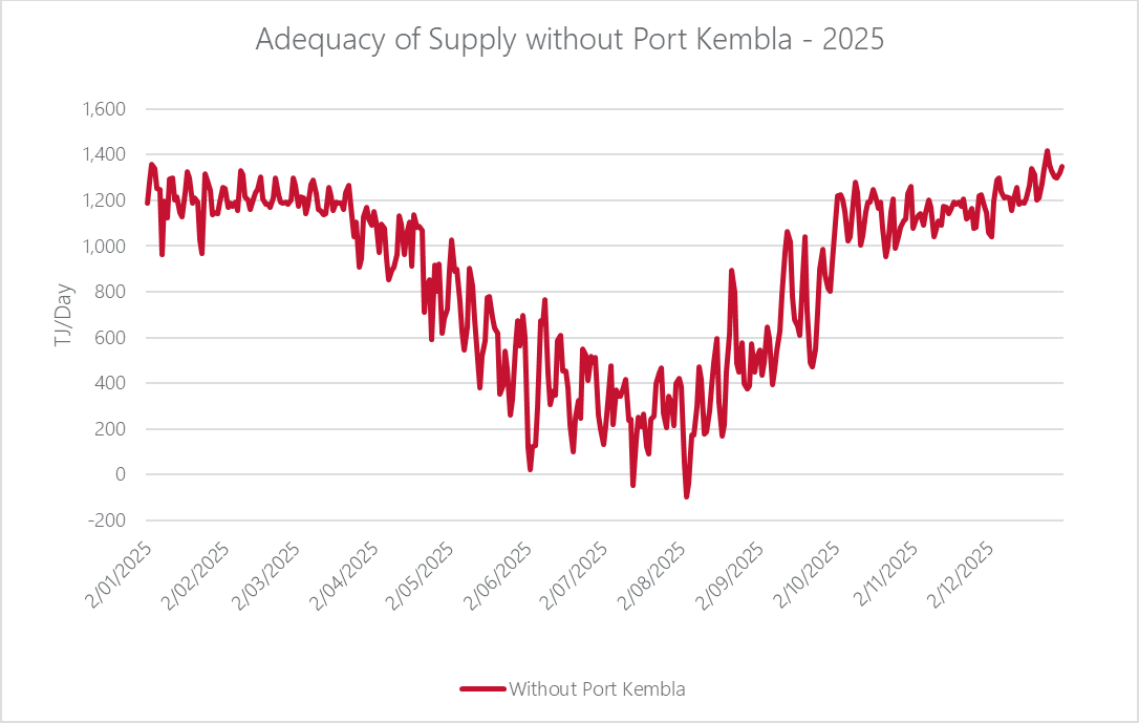
- The red dotted line adds the capacity that is available from storages, accounting for pipeline constraints in the south[8]; and
- Finally, the orange solid line shows the capacity available to the south with the construction of the Port Kembla Gas Terminal (PKGT).

AEMO states that[9]:

> *"Without new supply options, and if PKGT's commissioning and operation was delayed until after winter 2023, then peak day shortfalls of up to 100 TJ/d could occur in Victoria in the 2023 winter season under extreme peak demand conditions".*

The following figures present the "production and pipeline capacity" and "forecast Southern Demand" gap in 2025 from the above graph. Note that according to AEMO, these are "consistent with the 2015 reference weather patterns, and under 1-in-20 extreme peak demand conditions". It should also be noted that this assumes, amongst other things, that the Dandenong LNG storage is fully utilised.

Figure 4: Difference in "production and pipeline capacity" and "forecast Southern Demand"



Source: OGW analysis based on AEMO's 2021 GSOO

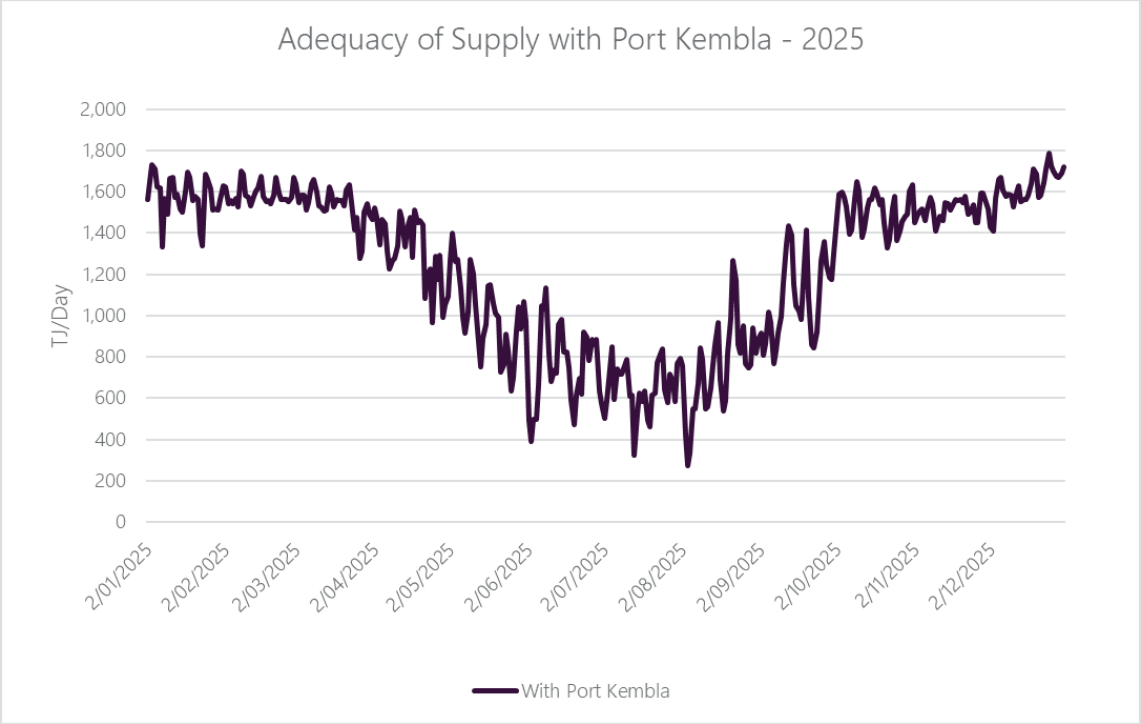
Based on our analysis of the underlying data:

- The largest supply gap is 98TJ/day; and
- A negative supply gap is expected on 3 days in 2025.

8 For example, AEMO states that: "*Victoria's SWP is projected to restrict the State's access to the full available capacity from Iona Underground Gas Storage during some critical periods, even accounting for the development of the Western Ring Outer Main (WORM) in late 2022*".

9 AEMO, *2021 Gas Statement of Opportunities*, page 55

Figure 5: Difference in "Production, pipeline, constrained storage and PKGT" and "forecast Southern Demand"



Source: OGW analysis based on AEMO's 2021 GSOO

As can be clearly seen, there is no gap expected under 1-in-20 extreme peak demand conditions in southern markets, if the Port Kembla LNG import terminal gets built[10], absent any allowance to AEMO's forecasts for other recent changes affecting the supply/demand balance in southern markets (discussed in more detail in the next section). AEMO affirms this in their GSOO[11]:

> *Producers' forecasts of existing and committed maximum daily production capacity would be sufficient to avoid domestic peak day gas shortfalls until at least 2026 under most circumstances, provided all developments proceed to schedule.*

This aligns with AEMO's view, as presented in the VGPR, which states that[12]:

> *…there is sufficient available supply for a 1-in-20 peak system demand day in 2025 by utilising Dandenong LNG and an increased reliance on New South Wales supply.*

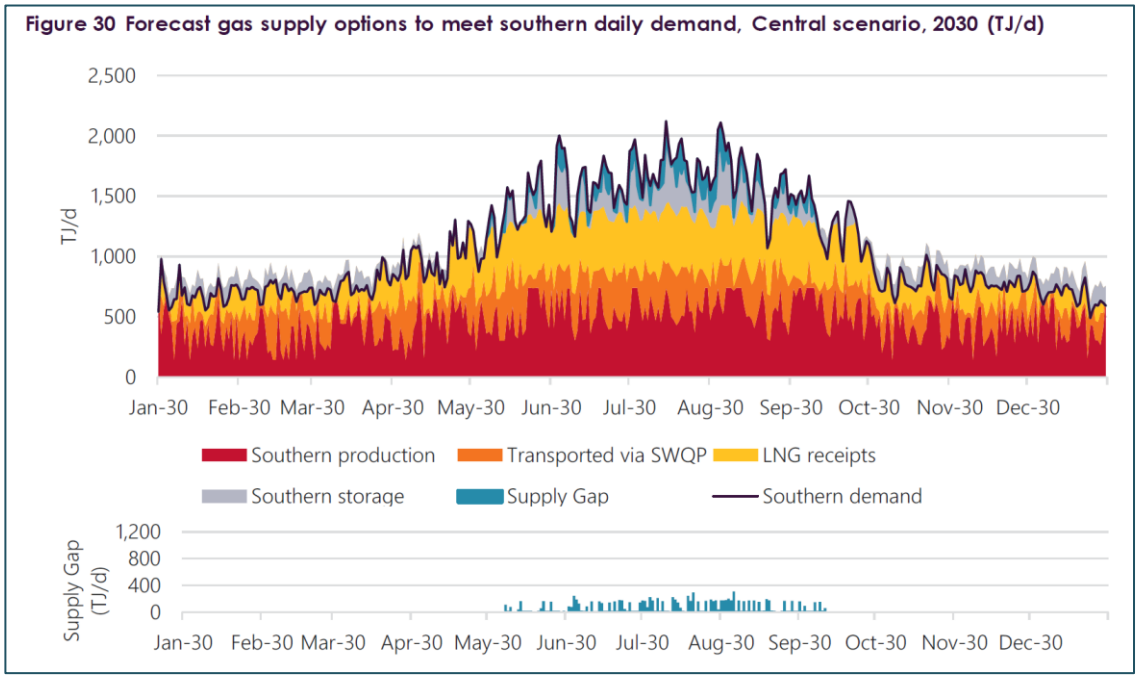
Notwithstanding the above, in the GSOO, AEMO are forecasting a significant supply gap (both magnitude and frequency) in 2030, as supply dwindles.

10 Which is what AEMO assumes will occur, noting that we have relied upon AEMO's published forecasts in this part of the analysis. For the avoidance of doubt, it is our understanding that at the time of writing, Port Kembla LNG import terminal had not yet reached FID.

11 AEMO, *2021 Gas Statement of Opportunities*, page 53

12 AEMO, *2021 Victorian Gas Planning Report*, page 48

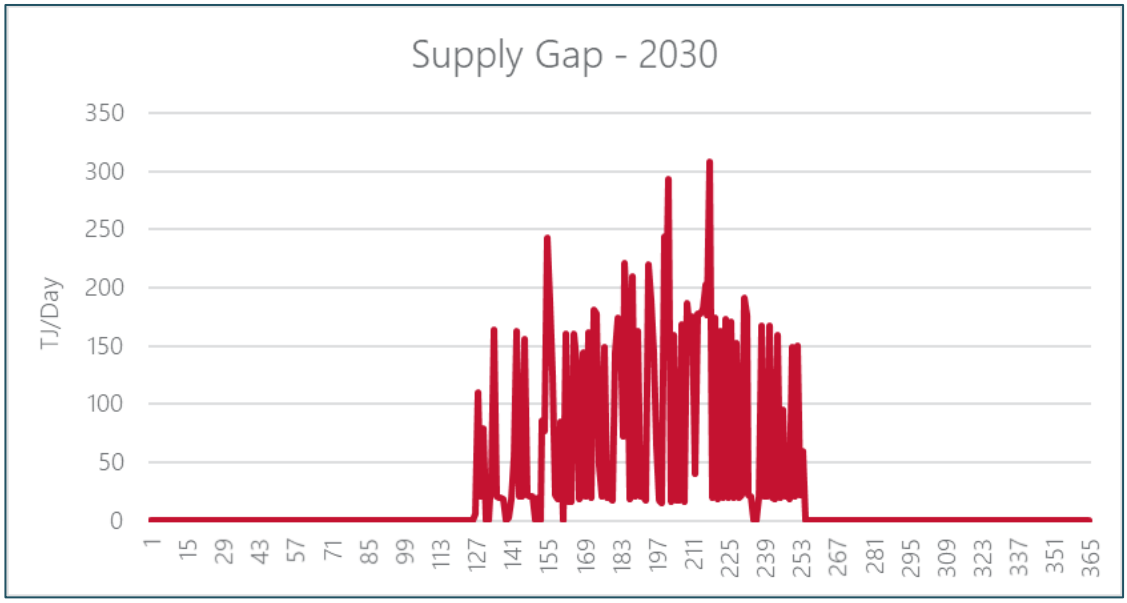
Figure 6: Forecast gas supply options to meet Southern daily demand, central scenario, 2030 (TJ/d)



Source: AEMO, *2021 Gas Statement of Opportunities*, page 56

The following figure drills down on the supply gap in 2030 in more detail.

Figure 7: Supply gap in 2030

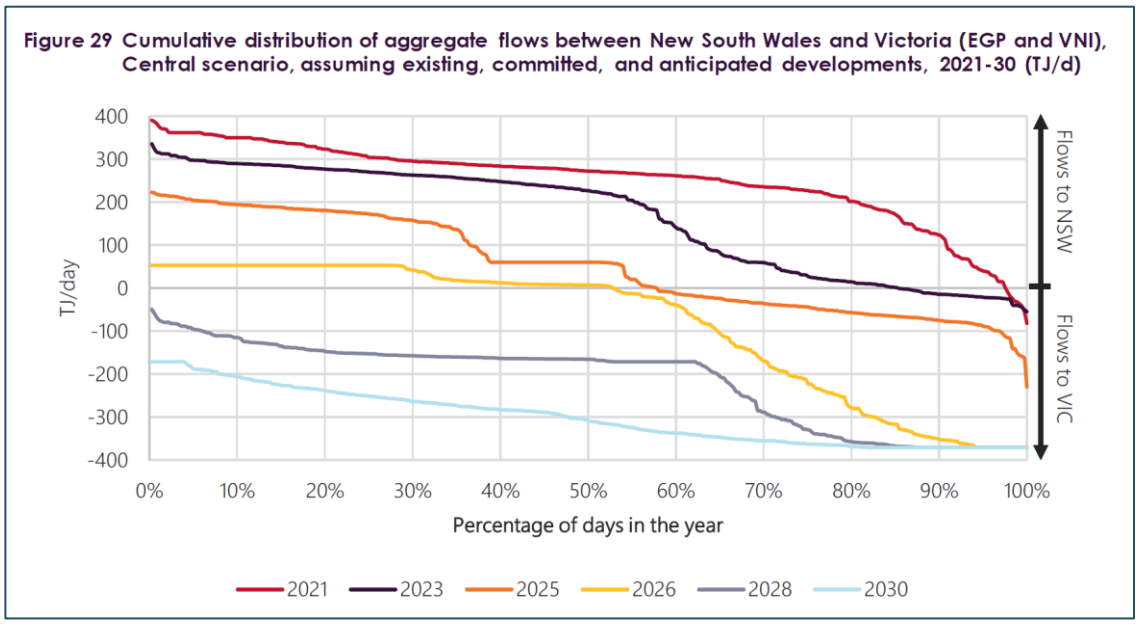


Source: OGW analysis based on AEMO's 2021 GSOO (figure 30)

Is it important to note that flows between Victoria and NSW are expected to reverse over time. For example, currently, gas flows north to NSW around 98% of the time (Eastern Gas Pipeline (EGP) and the Victorian NSW Interconnector (VNI - Culcairn)). In 2026, northerly flows to NSW are expected to occur around 53% of the time, with southern bound flows at level of capacity of the transmission system for around 6% of the year.

In 2028, gas is expected to flow south at all times of the year, with these flows forecast to be at the existing capacity of the transmission network (EGP and VNI) for around 13% of the time[13], with this increasing to, in the order of, 25% by 2030.

Figure 8: Cumulative distribution of aggregate flows between NSW and VIC (EGP, VNI)



Source: AEMO, *2021 Gas Statement of Opportunities*, page 57

As AEMO states[14]:

> *"Current infrastructure constraints on the MSP[15] limit the ability for northern supply to help cover southern shortfalls during maximum daily demand periods. At these times, and without further pipeline expansions, attempts to redirect gas earmarked for LNG export are unlikely to be effective in maintaining gas security"*

Following on from this, AEMO itself notes that[16]:

> *Further investments to address forecast supply gaps should be cognisant of the sector transformation underway and be adaptable to manage future changes in gas consumption patterns. Prudent options could include investments that can:*
>
> *• Flexibly match supply with seasonal demand and deliver variable annual supply efficiently.*
>
> *• Manage peak demand needs, **potentially through electrification, fuel switching**, and energy efficiency [emphasis added]*

13 Our understanding is that the in the order of 200 TJ/d of imports can be received from the PKGT via the EGP and VicHub, whilst supplies that can be received from the MSP via Culcairn are limited to 195 TJ/d, despite maximum capacity being listed 226TJ/day, due to capacity constraints in the New South Wales transmission network (AEMO 2021, *Victorian Gas Planning Report*, page 67).

14 AEMO, *2021 Gas Statement of Opportunities*, page 53

15 Moomba Sydney Pipeline

16 AEMO, *2021 Gas Statement of Opportunities*, page 4

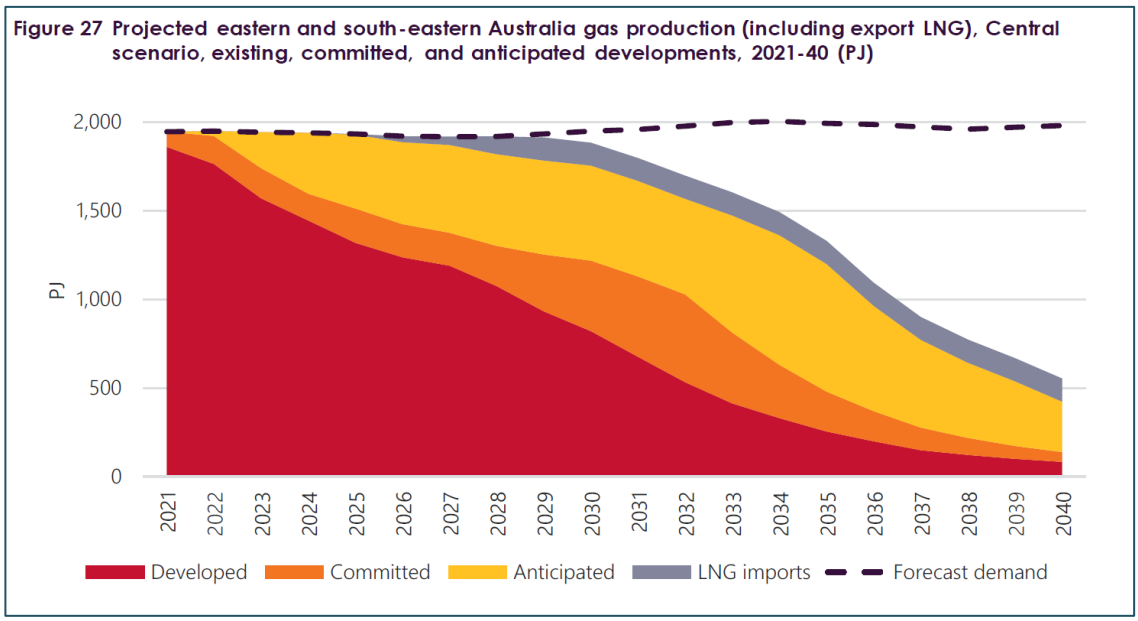
Notwithstanding the above, AEMO states in its 2021 GSOO that[17]:

> *"…while not considered in the scenario collection for this year's GSOO, a scenario with greater electrification of residential heating (or other heating alternatives to gas) would drive down Victoria's maximum daily demand for gas much faster than currently forecast. This possibility will be explored in more detail in future GSOOs, and AEMO's 2022 Integrated System Plan"*

Finally, the figure below shows the expected production forecast if existing, committed, and anticipated projects are developed, and all associated reserves and resources are commercially recoverable to meet demand in the long term. As AEMO states[18]:

> *"Provided all committed and anticipated projects are developed, there is projected to be sufficient supply to cover both extreme peak demand conditions and seasonal demand requirements until at least 2029….*
>
> *The figure shows that new supply options will be required across eastern and south-eastern Australia towards the end of the decade to ensure domestic and LNG export demand is met to the end of the outlook period"*

Figure 9: Supply/demand gap



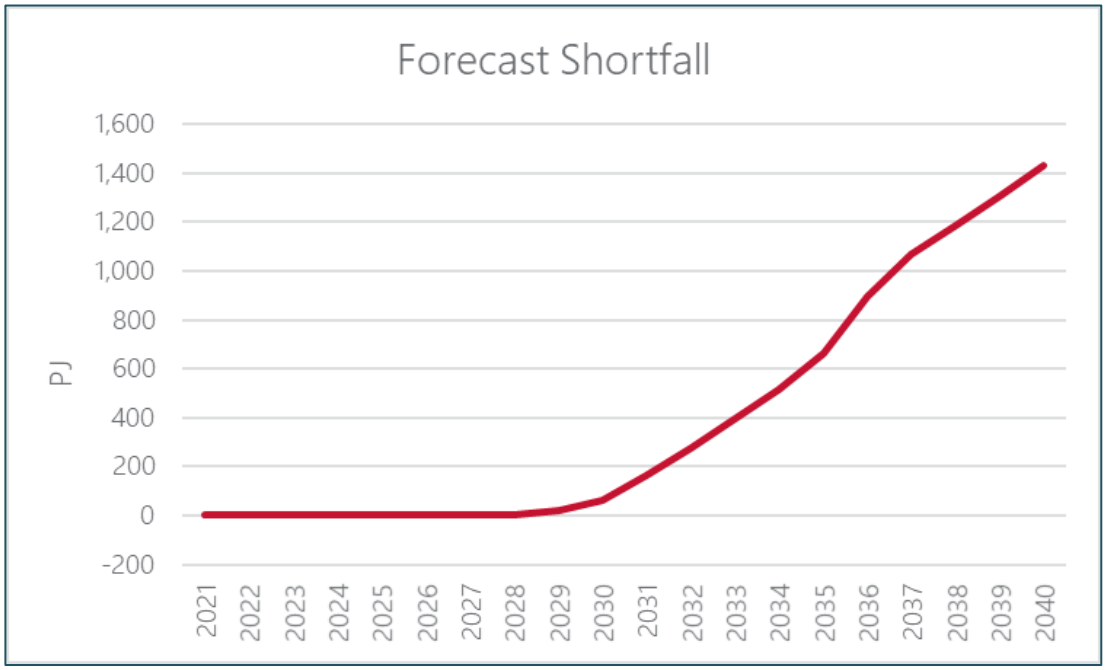
Source: AEMO, *2021 Gas Statement of Opportunities*, page 55

The magnitude of the shortfall is highlighted in the below figure.

17 AEMO, *2021 Gas Statement of Opportunities*, page 38

18 AEMO, *2021 Gas Statement of Opportunities*, pages 6 and 54

Figure 10: Annual Supply Shortfall (PJ)



Source: OGW analysis of AEMO data (Figure 27 of 2021 GSOO)

As shown in Figure 8, AEMO is forecasting a supply shortfall from 2029 even with the assumptions that committed, and anticipated projects are developed, and all associated reserves and resources are commercially recoverable. The gas supply shortfall rises steeply from 2029 to 2040.

2.3. Our summary of AEMO's view of the supply/demand situation

In summary, our understanding of AEMO's view of the supply/demand situation in Southern Markets and Victoria in particular is that:

- Without an import terminal at Port Kembla or other anticipated projects, AEMO is forecasting a supply gap of up to ~100TJ/day, for 3 days a year in 2023;
- With an import terminal at Port Kembla, and no other change, AEMO's modelling is indicating that there would be no supply gap in 2023;
- Moving beyond 2023, flows between Victoria and NSW are expected to reverse over time. For example:
  - Currently, gas is flowing north in the order of 98% of the time,
  - In 2026, this is expected to be for in the order of 53% of the time, with flows at capacity (EGP plus VNI) for around 6% of the year; and
  - In 2028, gas is expected to flow south at all times of the year, and be at existing capacity for around 13% of the time.
- This means that absent any investment to increase north/south transmission capacity, any supply imbalances affecting the Victorian market cannot be alleviated by bringing more gas from northern markets;

- AEMO has not, in its Central case, assumed any large scale program of electrification of gas substitution in Victoria; and
- AEMO is projecting there to be sufficient supply to cover seasonal demand requirements until at least 2029.

3. Factors that have changed since AEMO developed its forecasts

3.1. Objective of section

The objective of this section is to summarise the factors that have changed since AEMO's forecasts were developed, including that:

- At least two major industrial customers have announced their closures;
- APA has reached FID on its expansion of the SWQP and MSP; and
- The policy environment surrounding gas supply and demand has changed.

3.2. At least two major industrial customers have announced their closures

3.2.1. What has changed?

In February, 2021, Exxon Mobil announced they were closing their Altona refinery and converting it to an import terminal. This has a direct impact on gas demand, and moreover, it has a cascading effect on the consumption of gas by other consumers, in particular Qenos, the polyethylene and polymer producer, who announced that it will also close two of its production units (~50% of its plant) at its Altona plant.

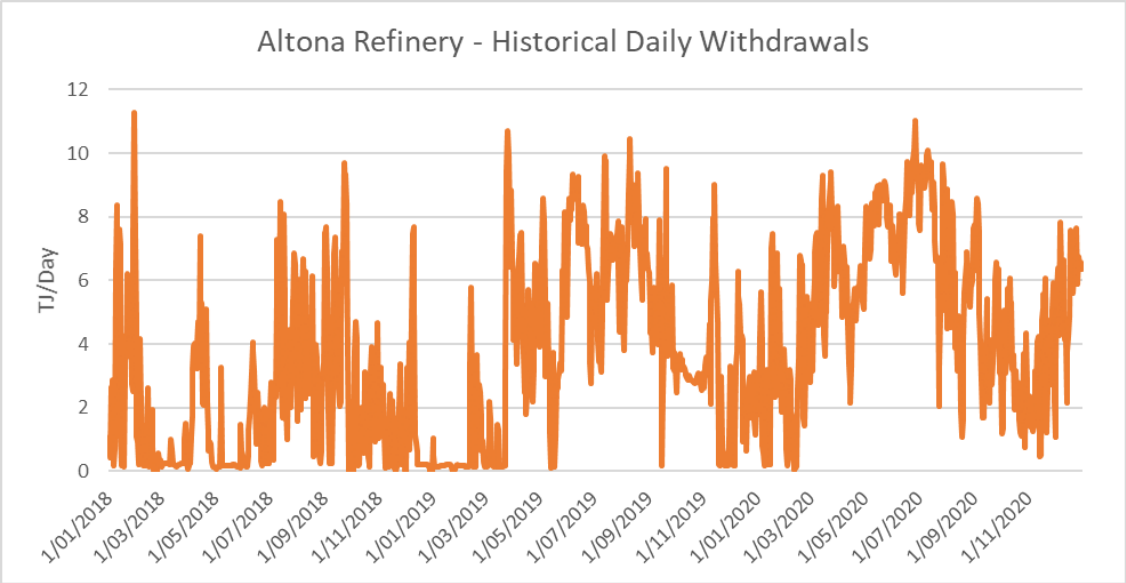
We are of the opinion that the closure of the Altona refinery and reduced production from Qenos' production facility, will not lead to increased local production from other producers (which in turn would require additional gas to be supplied to those producers), rather, their closure/reduced production is likely to lead to the increased importation of those products (e.g., refined petroleum products from South East Asia).

3.2.2. What is the likely impact of that change?

The closure of Altona refinery and the significant reduction in production from Qenos will demonstrably reduce the amount of demand that is placed on the VTS (including on peak days).

The following figure summarises the Altona Refinery's recent historical demand for gas.

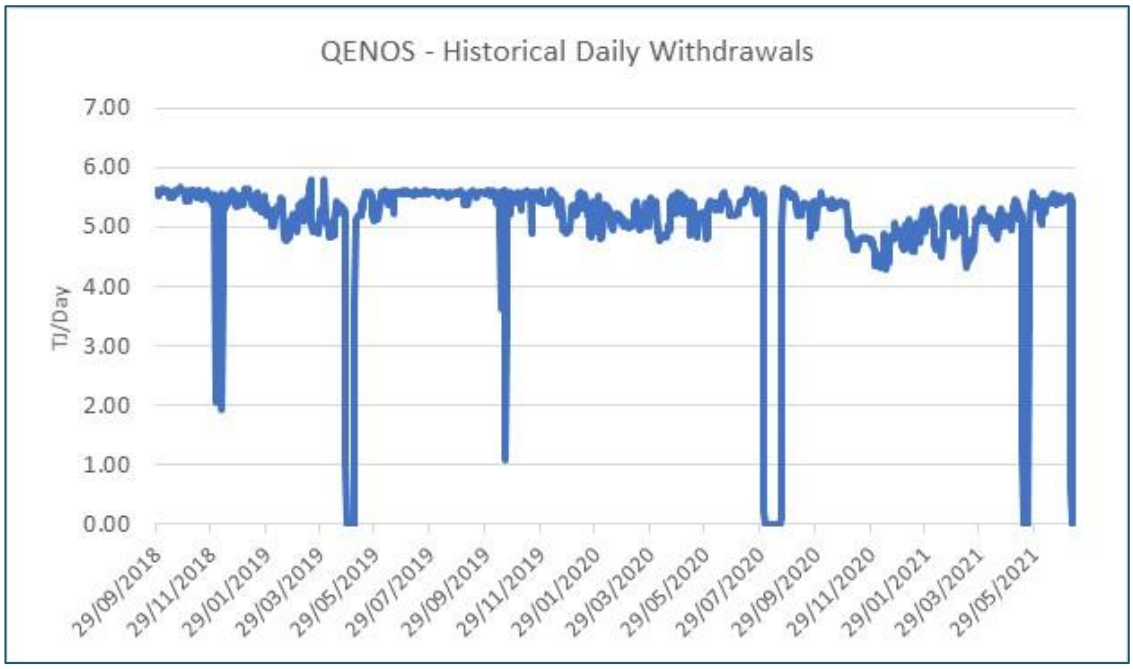
Figure 11: Altona refinery - Recent Historical Gas Demands



Source: OGW analysis of information provided by APA

The following figure summarises Qenos' recent historical demand for gas.

Figure 12: Qenos - Recent Historical Gas Demands



Source: OGW analysis of information obtained from Gas Bulletin Board

We have adopted the following simplified methodology to estimate the impact that their change in circumstances might have on both average and peak demand:

- **Reduction in Daily Average Demand**: Average consumption over the previous 3 years * estimated percentage change in reduction (100% for the Altona Refinery; 50% for Qenos[19])
- **Reduction in Coincident Peak Demand**: Average consumption over the previous 3 years on days when the DWGM peaked * estimated percentage change in reduction (as per above).

The following table summarises the results.

Table 6: Impact on Demand

Key Issue	Peak Demand	Annual and Daily Average
Altona Refinery load reduction	▪ Peak (TJ/day): 4.74	▪ Daily Average (TJ): 3.76 * 100% reduction (closure of refinery) ▪ Annual (TJ): 1372 reduction
Qenos load reduction	▪ Peak (TJ/day): 2.5TJ	▪ Historical daily average of 5TJ/day * 50% = 2.5TJ/ay ▪ Annual (TJ) = 912TJ
TOTAL	▪ **Peak (TJ/day) = 7.24**	▪ **Annual (TJ) = 2280**

19 *Qenos reconfigures Altona manufacturing facilities*, Media Release, 19 May 2021 ("*The planned changes, which come into effect later this year, will involve the closure and mothballing of one of Qenos' two Altona ethylene units as well as one of the two polyethylene plants*")

3.3. The SWQP/MSP upgrade has been committed to

3.3.1. What has changed?

APA has recently announced that it has reached FID to commence the expansion of transportation capacity on its East Coast Grid, linking Queensland with southern markets, by approximately 25%[20]. APA also announced a significant new East Coast Grid gas transportation agreement (GTA) with Origin Energy.

APA states that[21]:

> *APA's new three-year GTA with Origin Energy will commence on 1 January 2023 and will support Origin's energy needs in the southern markets, including winter peak demand and ahead of projected potential 2023 supply risks. Under this agreement Origin could meet over half of NSW's winter demand*

There is an option to extend the agreement by a further two-years.

APA further states that[22]:

> *The expansion will be delivered in two stages and at a capital investment of around $270 million. It will increase winter peak capacity of the East Coast Grid by 25% through additional compression and associated works on both the SWQP and MSP. The SWQP and the MSP are the key pathways for delivery of gas from Queensland and the Northern Territory, to southern markets.*
>
> *The first stage of expansion works will increase Wallumbilla to Wilton capacity by 12% and is targeted for commissioning in the first quarter of CY2023 ahead of forecast southern state winter supply risks identified in the 2021 AEMO Gas Statement Of Opportunities.*
>
> *Stage 2 of the expansion works, which will add a further 13% of capacity, will be staged to meet customer demand and is currently targeted for commissioning towards the end of CY2023.*

3.3.2. What is the likely impact of that change?

APA's expansion of the SWQP/MSP has implications for the economics of other (alternative) supply sources that AEMO was reflecting in its forecasts, and (potentially) the need for infrastructure investments to support those supply sources, along with the broader supply/demand balance within southern markets.

The estimated impact of this augmentation is that it will allow up to an extra 100TJ/day to flow into Sydney on peak demand days – with a consequent impact on flows into Melbourne, subject to transmission pipeline capacity being available (discussed in next section), based on the 25% increase in current capacity of ~ 400TJ/day[23].

Notwithstanding the above, for the purposes of this analysis, we would not expect APA's announcement to impact the likelihood of the Port Kembla Gas Terminal being constructed, given its current progression (with some reports indicating that it is 4 months into construction[24]) and relative importance to the supply demand balance over the short to medium term.

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20 APA, *ASX Announcement*, 5 May 2021

21 Ibid

22 Ibid

23 https://www.aemc.gov.au/energy-rules/national-gas-rules/gas-scheme-register/qld-south-west-queensland-pipeline; aligns with Figure 24, *2021, Gas Statement of Opportunities*, page 48

24 https://www.afr.com/companies/energy/construction-under-way-at-nsw-lng-terminal-20210809-p58h18

3.4. The policy environment surrounding gas supply and demand has changed

3.4.1. What has changed?

Victoria's Climate Change Act 2017 sets a target of net-zero emissions by 2050 and is designed to provide a clear signal to all sectors of the Victorian economy regarding the need for significant and sustained action to reduce emissions. More broadly, as part of Victoria's Climate Change Strategy, the State Government has set targets to reduce the State's greenhouse gas emissions from 2005 levels by 28-33% by 2025 and 45-50% by 2030.

The Victorian Government is also on record as investigating pathways to decarbonise its gas network and it explicitly states in its *Victorian Gas Substitution Roadmap Consultation Paper* that[25]:

> *"Electrification, hydrogen and biogas will all likely play a role in the decarbonisation of gas. Residential gas use and some commercial and industrial gas use can be readily electrified.* ***Some electrical appliances are already more energy efficient and cost-effective than their gas counterparts****, particularly where households have rooftop solar photovoltaic (PV) panels* ***[emphasis added]***

In the 2021 GSOO, which was published in March 2021, AEMO states that[26]:

> *"…while not considered in the scenario collection for this year's GSOO, a scenario with greater electrification of residential heating (or other heating alternatives to gas) would drive down Victoria's maximum daily demand for gas much faster than currently forecast. This possibility will be explored in more detail in future GSOOs, and AEMO's 2022 Integrated System Plan.*

Notwithstanding this, AEMO itself notes that[27]:

> *Further investments to address forecast supply gaps should be cognisant of the sector transformation underway and be adaptable to manage future changes in gas consumption patterns. Prudent options could include investments that can:*
>
> *• Flexibly match supply with seasonal demand and deliver variable annual supply efficiently.*
>
> *• Manage peak demand needs,* ***potentially through electrification, fuel switching****, and energy efficiency* ***[emphasis added]***

Importantly, AEMO's *Inputs, Assumptions and Scenarios Report* (IASP), which was published in July 2021, 4 months after the GSOO, and which details how AEMO *"will model the future in its forecasting and planning publications for the rest of 2021 and into 2022"*, states that[28]:

> *The Net Zero 2050 scenario represents a future that delivers action towards an economy-wide net zero emissions objective by 2050 through technology advancements. This transition focuses on short-term activities in low emission technology research and development to enable deployment of commercially viable alternatives to emissions-intensive activities in the 2030s and 2040s. Stronger economy-wide decarbonisation, particularly industry electrification, occurs in later years as the 2050 deadline approaches.* ***Consumers are initially continue (SIC) to heat their homes in the same manner they do today, but by the mid-2030s nearly half the current gas heating has been electrified, and in the final years of the horizon nearly all residential heating is electrified*** *[emphasis added]*

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25 Victorian Government, *Help Build Victoria's Gas Substitution Roadmap*, Consultation Paper, pg 6

26 AEMO, *2021 Gas Statement of Opportunities*, page 38

27 Ibid, page 4

28 AEMO, *2021 Inputs, Assumptions and Scenarios Report*, page 13

The highlighted section portends to the potential impact that AEMO expects could occur under a Net Zero 2050 scenario, which presumably reflect how it might model the impact of Victoria's already legislated target of net-zero emissions by 2050.

3.4.2. What is the likely impact of that change?

Any move to decarbonise Victoria's gas grid, will, everything else being equal:

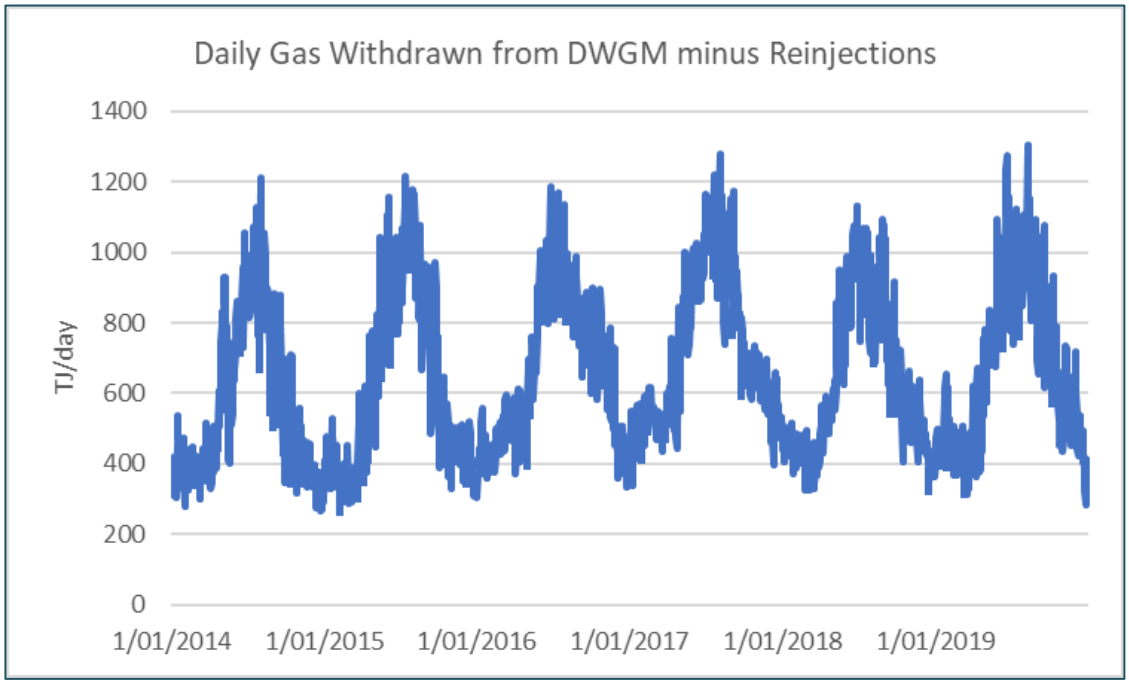
- Lead to a significant amount of gas load being electrified, which, if AEMO's IASR assumptions were adopted, would lead to nearly half the current gas heating load being electrified by the mid-2030s; and / or
- Lead to significant amounts of renewable gases entering the system, which[29]:
  - If they are hydrogen, might be at a distributed (distribution level) scale, avoiding APA's transmission network[30] but providing peak demand support (i.e., they would operate in a manner that would reduce peak demands placed on APA's transmission network); or
  - If they are biomethane or synthetic renewable methane, may not necessarily be in locations that would utilise the existing transmission network (nor might they be of a scale that would necessitate connection at transmission level).

Hydrogen and synthetic methane production will also add demand to the Victorian electricity system in the form of the need for additional renewable electricity production.These changes – particularly the electrification of residential gas heating loads – would, if they were to eventuate, have a materially different impact on total consumption (PJ) as compared to peak day demand, given the temperature dependency of gas demand in the DWGM. The following figure illustrates the variability of demand in the DWGM between 2014 and 2019.

29 For the avoidance of doubt, in our opinion, there are currently a number of impediments in the Rules and Law to the blending of hydrogen into natural gas networks, as well as to the connection of renewable gas facilities at a distribution network level. For example, the current definition of 'natural gas' in our opinion, precludes the blending of hydrogen, and the Law and the Rules do not enable the registration of any gas production facilities that are connected to the distribution system. Notwithstanding this, it is our understanding that these impediments are known to policy makers at both a State and Federal Government level, and that there is a program of work to change the relevant parts of the Law and Rules that are considered to be an impediment. For example, Minister Taylor has recently stated that as part of the Energy National Cabinet Reform Committee, "*Ministers agreed on an expedited process to amend the National Gas Law, National Energy Retail Law and subordinate instruments so hydrogen blends, biomethane and other renewable methane gas blends are brought within the national energy regulatory framework*" (https://www.minister.industry.gov.au/ministers/taylor/media-releases/energy-national-cabinet-reform-committee-1)

30 The reason for this is that there is significantly more uncertainty as to the ability for hydrogen to be blended into gas transmission networks as compared to gas distribution networks, due to materials that the pipelines are generally constructed from and the pressures at which they operate.

Figure 13: Daily gas demand in the DWGM



Source: OGW analysis based on data extract from NEO data subscription service

As AEMO notes in their GSOO[31]:

> *Industrial loads such as aluminium and chemical production, as well as some household and commercial loads, such as cooking and hot water demand, operate consistently across the year. Over the winter months (June to August in particular), additional gas is used for heating in households and business premises. On average, winter peaks in Victoria are two to three times higher than summer peaks, due predominately to heating load (see Table 3 and Table 4).*

The tables referred to by AEMO in the above quote are reproduced below.

Figure 14: Maximum Summer and Winter Demand forecasts; 1-2 and 1-20 year (TJ/day)

Table 3 Total 1-in-2 and 1-in-20 forecast maximum demand, summer, all sectors excluding GPG, including UAFG (TJ a day [TJ/d])

	NSW		QLD (incl LNG)		QLD (excl LNG)		SA		TAS		VIC	
	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20
2020*	251		4,331		330		94		19		410	
2021	283	306	4,519	4,540	351	372	107	115	21	23	453	585
2023	285	309	4,537	4,558	351	372	108	116	21	23	442	571
2025	286	311	4,556	4,578	341	363	108	116	22	24	435	563
2030	288	312	4,537	4,556	322	341	108	116	22	24	442	573
2040	295	320	4,538	4,558	323	343	108	116	24	26	483	636

* The 2020 values show actual maximum demand.

31 AEMO, *2021 Gas Statement of Opportunities*, page 35

Table 4 Total 1-in-2 and 1-in-20 forecast maximum demand, winter, all sectors excluding GPG, including UAFG (TJ/d)

	NSW		QLD (incl LNG)		QLD (excl LNG)		SA		TAS		VIC	
	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20
2020*	438		4,347		346		147		21		1,213	
2021	457	485	4,527	4,549	359	381	156	165	23	25	1,153	1,265
2023	463	489	4,545	4,566	359	380	158	166	23	25	1,124	1,237
2025	465	493	4,565	4,586	350	371	158	166	23	25	1,101	1,205
2030	468	497	4,546	4,565	331	350	158	167	24	26	1,144	1,252
2040	478	507	4,548	4,568	333	353	158	167	26	28	1,267	1,390

* The 2020 values show actual maximum demand.

Source: AEMO, *2021 Gas Statement of Opportunities*, page 35

As AEMO states[32]:

> *…on the maximum demand day, approximately 80% of the Victorian demand comes from residential and commercial customers, primarily for heating.*

The following figures illustrates the potential quantum of the impact of the electrification of residential heating and increased reliance on renewable gases, noting that the two factors are not necessarily mutually exclusive (i.e., it is possible that both wide-scale electrification could occur, and increased penetration of renewable gases occur).

Notwithstanding this, for the purposes the modelling we present below, we have treated them separately.

Impact of electrification

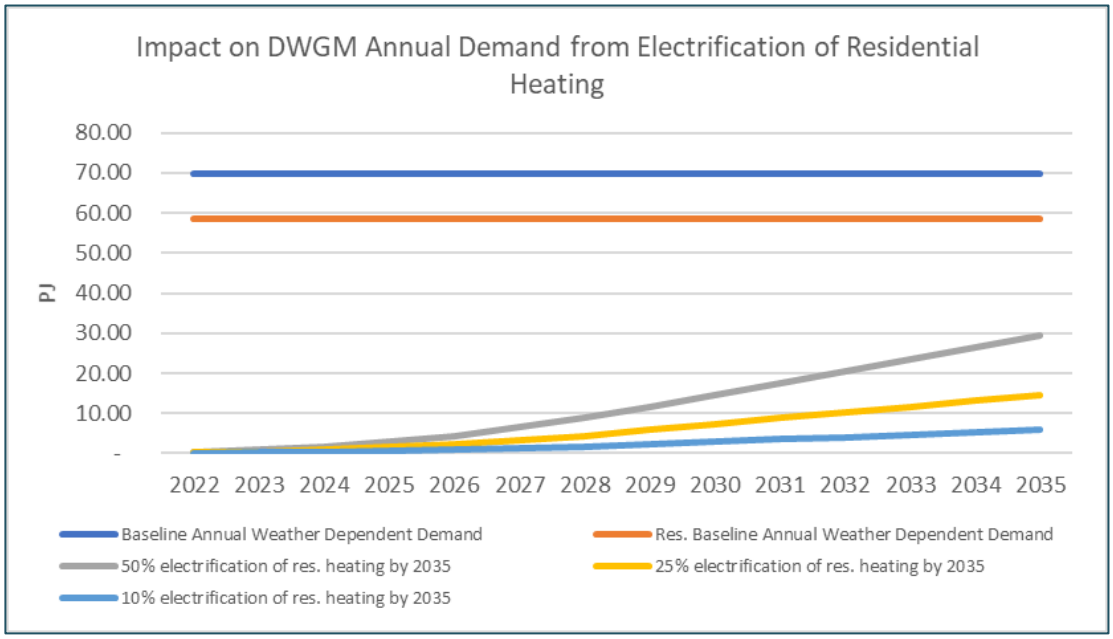
The following figures highlight the:

- Potential impact on annual gas demand of electrification of residential heating[33]; and
- Potential impact on peak day gas demand of electrification of residential heating.

32 AEMO, *2021 Gas Statement of Opportunities*, page 35

33 It should be noted that we have not assumed any material change to supply-side conditions affecting the electricity market (e.g., coal plant shutdowns). If electrification were to occur in an environment of coal power plant shutdowns, then there may be a need to increase reliance on GPG, which may counteract the reductions in direct gas consumption for heating purposes.

Figure 15: Potential Impact on Annual Demand of Electrification of Residential Heating

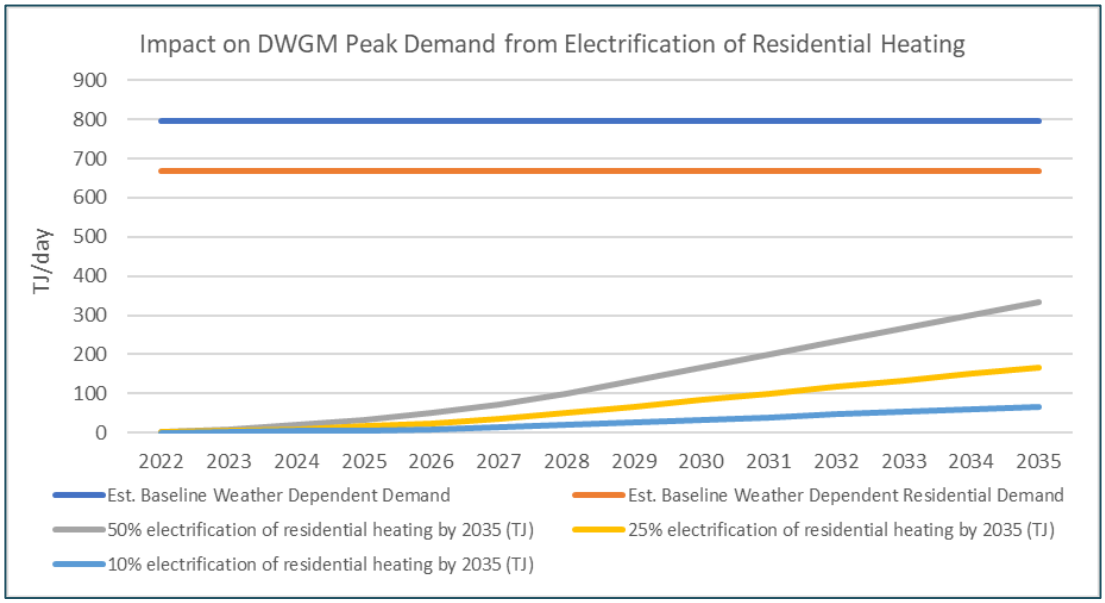


Notes: OGW analysis, based on: (a) weather dependent load is based on the average *total* load in each year between 2014 and 2019 in the DWGM, *less* the intercept (452TJ/day) resulting from a regression analysis of effective degree days (EDDs) - an index that is used to capture a range of weather variables - and actual DWGM demand across that time frame (noting that our intercept figure of 452TJ/day - i.e., the amount of load that is not weather dependent - is similar to the figures presented in Figure 12 above, which reproduce AEMO's summer maximum demand figures); (b) for simplicity, we have assumed that there is no change in annual weather dependent gas demands under our base case; and (c) we have proportioned the total amount of weather dependent demand to residential customers, based on their overall usage relative to the total usage of residential and commercial customers (~84%) as per the published RINs of the Victorian Gas Distribution businesses. Implicitly, this assumption assumes that all weather dependent demand is driven by residential and commercial usage, which broadly aligns with AEMO's statement on page 35 of the GSOO, which is reproduced on the previous page.

Figure 15 shows that, assuming that all weather dependent demand is driven by residential and commercial usage, then by 2035:

- 10% electrification of residential heating will result in a reduction of annual demand of around 6PJ;
- 25% electrification of residential heating will result in a reduction of annual demand of around 15PJ; and
- 50% electrification of residential heating will result in a reduction of annual demand of around 30PJ.

Figure 16: Potential Impact on Peak Day Demand of Electrification of Residential Heating



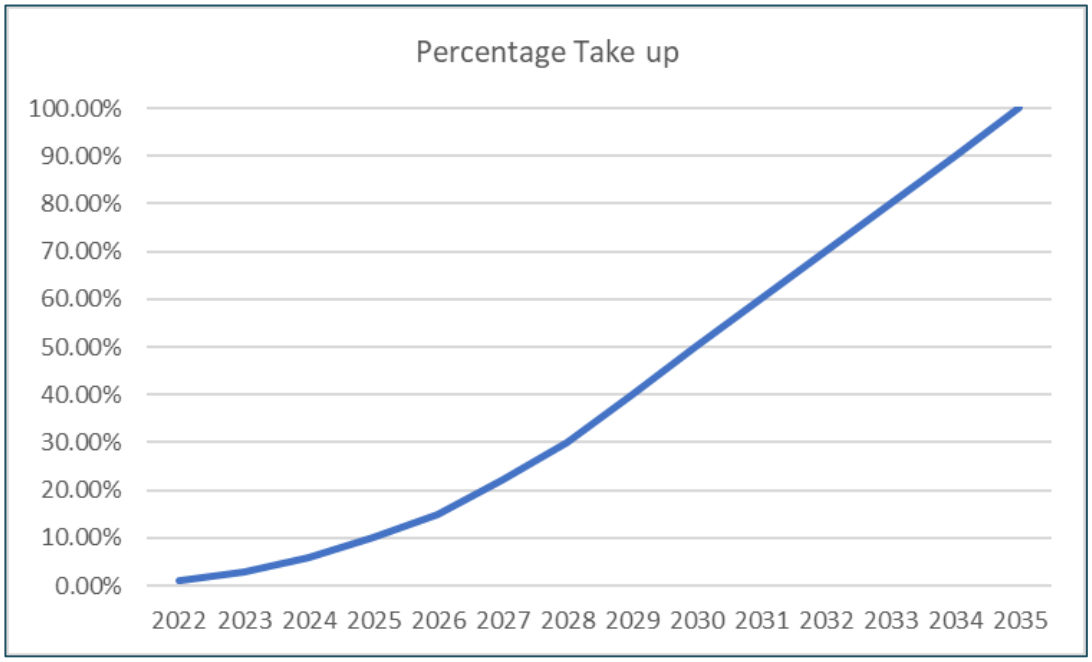
Notes: OGW analysis as per the approach outlined for Annual Demand, except that we assumed that total peak demand is 1250TJ/day.

Figure 16 shows that, assuming that all weather dependent demand is driven by residential and commercial usage, then by 2035:

- 10% electrification of residential heating will result in a reduction in peak demand of around 67TJ/day;
- 25% electrification of residential heating will result in a reduction of peak demand of around 167TJ/day; and
- 50% electrification of residential heating will result in a reduction of peak demand of around 335TJ/day.

The trajectory of electrification underpinning the above two graphs is outlined below.

Figure 17: Trajectory underpinning switch to electric heating (% of 2035 target)



Source: OGW estimate, noting that the "Percentage Take up" is the percentage of the final proportion of residential customers who are assumed to have had their current heating appliances electrified in 2035. So for example, if 50% of residential heating is assumed to be electrified in 2035 – as per AEMO's IASR – it is 100% of the 50%.

The actual trajectory of any widescale electrification will be dependent on a range of factors, including, but not limited to:

- The relative prices of gas and electricity, with the latter also reflecting the very opportunity cost to some customers of utilising excess production from their solar PV systems that would have otherwise been exported at very low feed-in-tariff rates;
- Customers' perceptions as to the different emissions intensity of the two fuel sources (and their willingness to pay);
- Customers' perceptions of future costs of gas and electricity, and their additional willingness to pay for particular features of gas as compared to electricity (e.g., perceived heating amenity); and
- The cost to the customer of switching to a different fuel source for their heating needs.

In relation to the latter, the cost to customers of switching over the period 2035 will differ, depending on whether:

- A customer already has a source of electric heating (e.g., air conditioning split system) that can be relied upon, without any additional upfront expenditure;
- A customer's existing gas heating appliance reaches the end of its useful life over the modelling horizon; or
- A customer has no existing source of electric heating, and their existing gas heating appliance does not reach the end of its useful life over the modelling horizon.

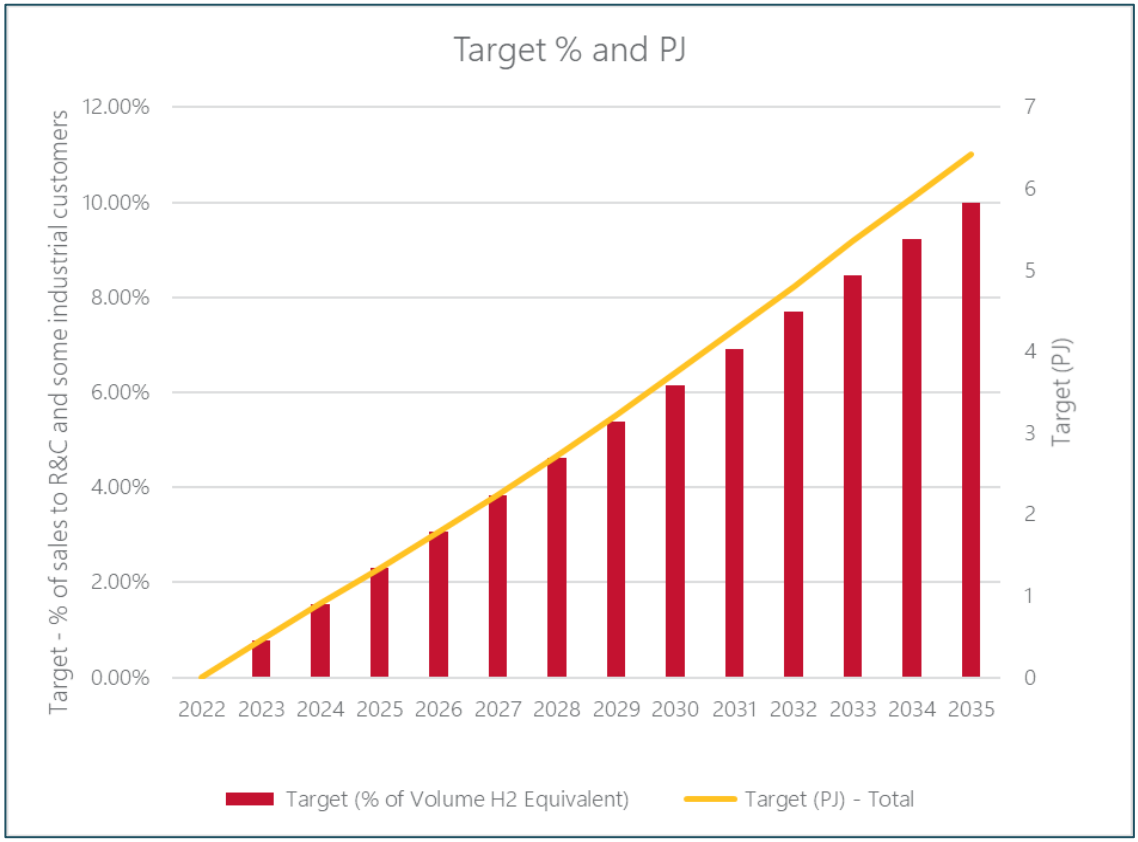
Whilst we have not explicitly modelled these different factors, our trajectory implicitly assumes that there are a sizable number of Victorian households who already have a source of electric heating (e.g., split system) in their home, which would allow them to switch fuels without having to make any material upfront investment.

Impact of renewable gases

The following figures highlight the potential impact on annual and peak day demand of increased penetration of renewable gases, in particular hydrogen.

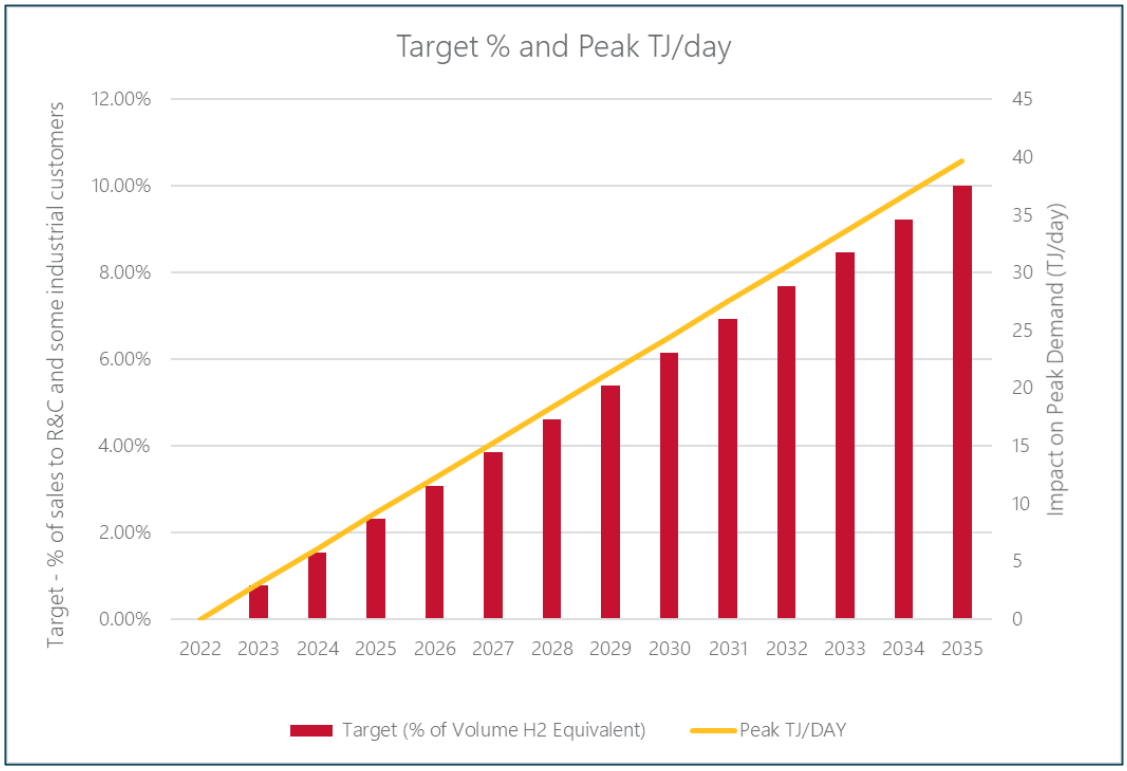
For the purposes of this analysis, we have assumed that renewable gases – namely hydrogen – are progressively increased over time to displace the use of natural gas use in the Victorian market. Consistent with a number of public statements by gas distribution businesses, we have assumed that the quantum of this displacement is, in 2035, 10% by volume hydrogen (H_2) equivalent (which equates to around 3% by energy). The basis upon which the 10% by volume is applied is the underlying forecast of demand in Victoria by AEMO's in its GSOO (see figure 34 of the GSOO).

Figure 18: Potential Annual Impact of Increased Penetration of Renewable Gases



Source: OGW

Figure 19: Potential Peak Day Impact of Increased Penetration of Renewable Gases



Source: OGW

3.5. Summary of impact on AEMO's GSOO forecasts

The following table summarises the potential impact that the above factors could have on AEMO's forecast of peak demand (TJ/day) to 2030.

Table 7: Impact on Peak Demand

Key Issue	Impact in 2025 (TJ/Day)	Impact in 2030 (TJ/Day)
Est. AEMO peak demand starting base	1250	1250
Increased Supply		
Increased supply resulting from expansion of the SWQP/MSP	100	100
Increased supply from Renewable Gases	9.15	24.42
Reduced Demand		
Reduced consumption from Altona Refinery and Qenos	(7.24)	(7.24)
Reduced peak day consumption due to electrification		
High (50%)	*(33.42)*	*(167.11)*
Medium (25%)	*(16.71)*	*(83.55)*
Low (10%)	*(6.68)*	*(33.42)*
Net Change in Supply Adequacy		
TOTAL Change - Medium Elec	133.1	215.21
TOTAL Change - High Elec	149.81	298.76
Supply Adequacy		
Original GSOO Peak Day Supply Adequacy with PKGT (Southern Mkts)	+273	-308
Peak Day Supply Adequacy after adjustments (Southern Mkts)	**+406.1 to +422.81**	**-92.79 to -9.24**

NOTES: OGW analysis

Our analysis indicates that as a result of the Victorian Government's legislated commitment to Net Zero by 2050, and reflecting AEMO's IASR that under a Net Zero scenario, nearly half the current gas heating could be electrified by the mid-2030s (which broadly aligns with the Victorian Government's pathways analysis), there may only be a very small supply shortfall (-9.24TJ) on peak demand days in 2030. To be clear, this assumes that additional north / south expansion capacity is enabled in order to allow the additional 100TJ/day facilitated by APA's expansion of the SWQP / MSP to reach Victoria.[34] If electrification were to lag AEMO's assumption, with only 25% of customers having their heating loads electrified by 2035, the supply shortfall is larger, but still not insurmountable (at -92.79TJ) in 2030. Options for covering this supply shortfall are discussed in the next section.

The following table summarises the potential impact that the above factors could have on AEMO's forecast of annual demand (PJ) to 2030.

Table 8: Impact on Annual Demand

Key Issue	Impact in 2025 (PJ)	Impact in 2030 (PJ)
	Increased Supply	
Increased supply resulting from expansion of the SWQP/MSP	None assumed for modelling	None assumed for modelling
Renewable Gases	1.34	3.73
	Reduced Demand	
Reduced consumption from Altona Refinery and Qenos	(2.28)	(2.28)
Reduced annual consumption due to electrification		
High (50%)	(2.93)	(14.64)
Medium (25%)	(1.46)	(7.32)
Low (10%)	(0.59)	(2.93)
	Net Change in Supply Adequacy	
TOTAL Change - Medium Elec	5.08	13.33
TOTAL Change - High Elec	6.55	20.65
	Supply Adequacy	
Original GSOO Supply Adequacy with PKGT (Southern Mkts)	No Shortfall	(65)
Annual Supply Adequacy after adjustments (Southern Mkts)	**No Shortfall**	**-51.7 to -44.35**

34 The SWQP/MSP expansion allows for more supply to be delivered to Sydney, which allows for an equivalent amount of Sydney-bound Longford production to be diverted to Melbourne.

NOTES: OGW analysis

The above:

- Reflects AEMO's underlying forecast that there is no supply gap in southern markets in 2025 under existing GSOO assumptions, therefore, the additional factors that we have discussed in this section which would otherwise reduce gas loads, would only contribute to a strengthening of this supply/demand position; however
- Even after incorporating the factors that we have discussed in this section of the report, there is still a supply shortfall in 2030 of 51.7PJ under the medium case, and 44.35 under our high case, assuming as given AEMO's other GSOO assumptions e.g., declining Longford supplies; LNG receipts; north / south transmission constraints for a substantial amount of the year. Whilst this shortfall is material, AEMO is forecasting no shortfall until 2029, beyond the AA period, and moreover, this figure is likely to be subject to significant uncertainty (e.g., the quantum of the reduction in Longford, noting the nature of any gas reservoir engineering analysis supporting this, and the inherent uncertainties that this entails). It also make no allowance for the potential for additional gas flowing from northern Australia.

4. Options for alleviating any forecast supply / demand imbalance towards the end of APA's AA period

4.1. Objective of section

The objective of this section is to:

- Outline the feasible options for alleviating any forecast supply / demand imbalance towards the end of APA's AA period, including:
  - Augmenting the South West Pipeline to accommodate increased withdrawals from Iona and/or LNG import terminals; and
  - Augmenting the Young-Culcairn link (Interconnect);
- Other more marginal options:
  - Augmenting the Dandenong LNG facility; and
  - Relying on price induced demand response of a formal, centralised, demand response mechanism.
- Outline the option(s) that is, in our opinion, likely to be economically attractive, in light of the factors that we have discussed in the previous sections and having regard to the general uncertainty regarding future gas market conditions.

4.2. Augment the South West Pipeline (SWP) for Iona/LNG Imports

The SWP connects Melbourne to supply from the Otway Basin, including providing access to the Iona Underground Gas Storage (Iona) facility.

The current capacity of the SWP is 426TJ/day east[35], however APA is planning to increase capacity by approximately 40 TJ/day via the proposed Western Outer Ring Main (WORM), which is expected to be completed by Q2 2023[36]. The WORM also allows for increased flows to the Iona underground storage facility and to Brooklyn and Wollert on the VTS.

In its 2021 GSOO, AEMO makes a number of statements suggesting that the SWP is, and will continue to be, a limitation on accessing supply from the western part of Victoria, particularly on peak demand days.

For example, AEMO states[37] that the SWP:

> *Projected to constrain flows during peak demand periods when the full capacity of the Iona UGS is most needed. Additional supply from the Otway Basin could not help support winter peak demand without upgrading or duplicating this pipeline.*

AEMO also states that[38]:

> *"Victoria's SWP is projected to restrict the state's access to the full available capacity from Iona UGS during some critical periods, even accounting for the development of the Western Ring Outer Main (WORM) in late 2022".*

35 AEMO, *2021 Victorian Gas Planning Report*, page 67

36 Refer to worm_update-04.pdf (apa.com.au)

37 AEMO, *2021 Gas Statement of Opportunities*, page 49

38 AEMO, *2021 Gas Statement of Opportunities*, page 55

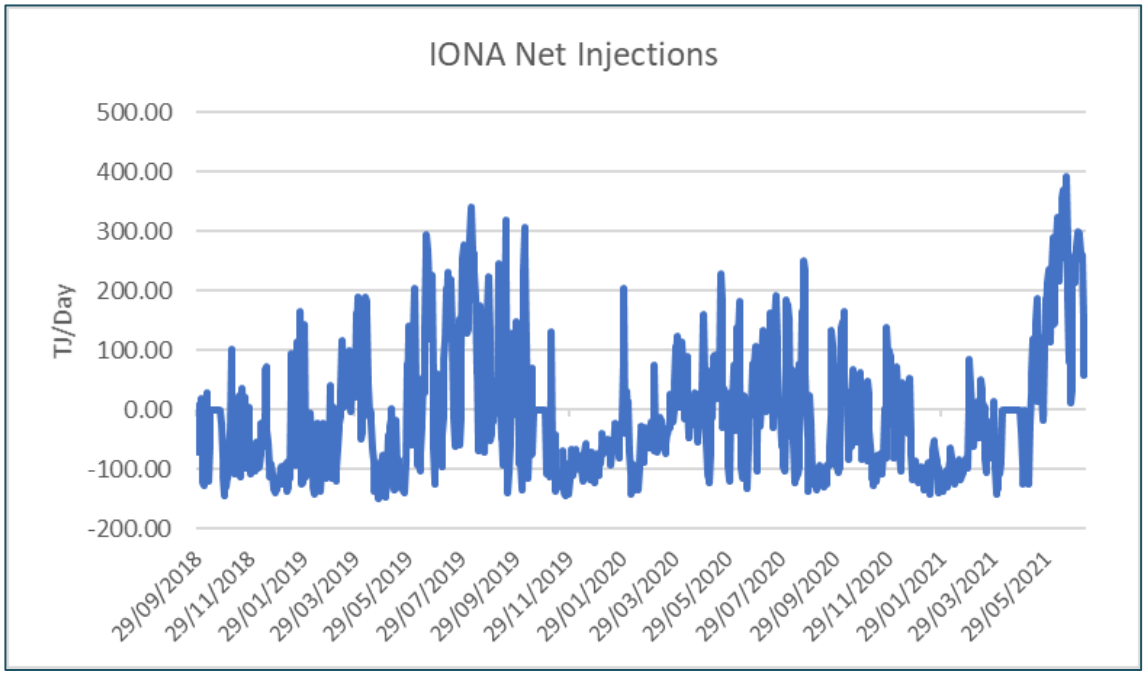
The key source of gas that utilises the SWP at present is Iona. Iona's current injection capacity is 520TJ/day[39], which exceeds the capacity of the SWP (even after the completion of the WORM). In its submission to APA's Capital Program, Lochard Energy, the owner of Iona, state that[40]:

> *The current phase of Iona expansion works will enable Iona to reach 570 TJ/d of SWP injection capacity from 2023. ….. Additionally, Lochard, in conjunction with its current and future customers, is advancing the planning works required for building further capacity at Iona. These works could deliver up to another 130 TJ/d of SWP injection capacity during 2023-2027 period.*

In summary, Iona's withdrawal capacity already exceeds the capacity of the SWP, and its proposed works would lead to withdrawal capacity of in the order of 700TJ/day.

Despite this, Iona's maximum net injection into the VTS has, in recent years, been 390TJ/day; less than the capacity of the SWP. It is not clear what specific factors have driven this, for example: whether it is only contracted to 390TJ/day; whether contracted market participants have chosen not to bid their Iona withdrawal rights at prices below market clearing prices; or whether on those days, the residual withdrawal capacity available to contracted parties is being used to service the South Australian market.

Figure 20: Iona Historical Daily Net Injections into SWP



Source: OGW analysis of GBB information; Net injections means Injections less Withdrawals

In addition to the Iona storage, there are two other projects that could utilise an augmented or expanded SWP, if/when they reach FID. These are:

- **Viva Energy LNG Import Terminal**: Viva Energy is seeking approval to develop a gas terminal at the Geelong Refinery[41]; and

39 As per AEMO's spreadsheet: "2021 GSOO Processing Transmission Storage Facilities.xls"

40 Lochard Energy, Submission to APA re VTS 2023-27 Capital Program, 30th June, 2021, page 2

41 https://www.vivaenergy.com.au/energy-hub/gas-terminal-project/about-our-project

- **VOPAK**: Vopak is investigating the feasibility of developing an offshore floating LNG import facility in Port Phillip Bay[42].

Based on AEMO information[43] provided as part of APA's consultation on Capital Issues for this AA, these two facilities could provide in the order of 600TJ/day MDQ, on top of what might be able to be provided by Iona. To support all facilities, significant additional capital expenditure to augment the SWP would be required. Alternatively, AEMO notes that LNG injections could be accommodated by backing down injections from Iona[44]. If this were the case, no (or minimal) expenditure would be required to augment the SWP.

Therefore, in summary, there are a number of SWP expansion options, each of which depends on a number of assumptions regarding whether or not the expansion should cater for none, one, or more of the LNG import terminals, which affects the magnitude of the expansion.

According to publicly available information from AEMO[45]:

- With Iona expansion only:
  - Additional compression at Winchelsea or downstream closer to Melbourne; and
  - Looping between Iona and Lara.
- With LNG terminal, and an assumption that Iona would not be backed down:
  - Additional compressor between Lara and Plumpton/Wollert.
  - Looping Lara to Brooklyn /Lara to Wollert.

Clearly, adding additional compression to support existing Iona withdrawal capacity has the advantage of leveraging an already completed investment. Although for the avoidance of doubt, the true test is whether the market has valued that existing withdrawal capacity enough to actually contract for it, subject to increased SWP capacity being made available. We are not in a position to assess whether or not this is the case, however it is a critical issue.

However, given our understanding of AEMO's GSOO and the broader conditions affecting the gas market, the disadvantage of adding additional compression to support existing Iona withdrawal capacity is that increasing the peak day capacity of the SWP to accommodate Iona's withdrawal capacity does not, in and of itself, materially increase the overall amount of gas that can be injected into the DWGM from Iona across the entire peak winter season. As AEMO indicates, the ability to provide (winter) seasonal support will be even more important in the future[46]:

> *"Over time, as maximum daily production continues to decline, the value of flexible seasonal "shaped" gas supplies is expected to increase to help cover monthly winter demand, not just extreme peaks".*

Iona's ability to provide this service will be a function of:

- The capacity of the Iona storage (i.e., how much gas Iona can hold, which can then be withdrawn over that peak period, absent any refilling);

42 https://vopakvictorialng.com/

43 AEMO, *Access Arrangement Roundtable Victorian Gas Planning Report,* slide 12

44 Ibid, page 14

45 Ibid, page 15

46 AEMO, *2021 Gas Statement of Opportunities,* page 6

- The maximum amount of gas that can be injected back into Iona from the DWGM on any given day to refill it (i.e., its refill rate, which the WORM will materially assist with); and
- The actual availability of gas (above Victoria's underlying demand for gas) to refill Iona during the peak winter period.

Put another way, the above factors limit a withdrawal holders' willingness to bid any (increased) withdrawal capacity into the market, even if the transmission capacity is available.

In the context of Victoria's overall gas demand, Iona's storage capacity/size, which is in the order of ~16PJ of usable capacity, is not of a scale that would allow it to operate as a seasonal storage - i.e., it is not able to be filled as at the start of winter, and then drawn down over the winter period in order to meet a *substantial* amount of Victoria's overall winter gas needs. For example, based on monthly gas consumption information contained in Table 24 of the VGPR (page 79) for 2021, Iona's 16PJ equates to 20.1% of the system consumption from June to August, and 13.45% of consumption over the May through September period.

This is not to say that it can't or will not be important in meeting peak day demand requirements over this period.

Moreover, market participants may find it difficult to refill Iona over this peak period, despite the increased capacity of the WORM, if:

- North / south transmission capacity is constrained (which AEMO projects to be the case for significant amounts of the year from 2026 onwards), as this makes it difficult to get more gas into Victoria from NSW/QLD during this period to refill Iona, *and*
- The majority of Victoria's indigenous gas is already projected to be relied upon to service demand throughout this winter period (i.e., there is unlikely to be surplus gas available during this period at commercially attractive rates, limiting market participants' ability to refill Iona in winter, despite there being no transmission constraint on re-filling).

In comparison, looping parts of the SWP to connect one or more of the LNG import facilities to allow their maximum gas injection during peak periods, whilst not backing down Iona, has the:

- Advantage of facilitating the connection of an additional, new source(s) of gas that can provide both peak demand support as well as increasingly valuable flexible seasonal gas supplies; *however*
- The potential disadvantage of being beholden to the economics of the Floating Storage Regasification Units (FSRU) facilities, which are highly flexible sources of supply which can be readily relocated *if* the supply/demand conditions in Victoria were to change in the future.
  - It is recognised that this flexibility can also be an advantage in the market under certain scenarios e.g., where it avoids investment in the SWP for a period while electrification takes place and peak demand is reduced.

The potential disadvantage is exacerbated under the market carriage model that operates in Victoria, if any pipeline expansion were required to support the FSRU facilities, as APA will not charge either of the LNG facilities (or Iona for that matter) for any expansion of the SWP, as there is no firm access provided to any individual user. The corollary is that it is:

- End customers that bear the costs of such investments, and/or
- APA that bears the financial risk if these assets turn out to be less useful to the market than what was envisaged when they were first developed (i.e., they are deemed to be 'stranded' or 'redundant' asset risk). This is because the Rules provide for the AER to, ex post, classify assets as 'redundant assets', if certain circumstances/factors eventuate. If this were to occur, this would result in their costs being removed from APA's capital base.

4.3. Augment the Young-Culcairn interconnect

AEMO states that the[47]:

> *The operator of the New South Wales transmission system north of Culcairn has advised AEMO that up to 195 TJ/d of imports into the DTS can be supported by winter 2021.*

AEMO notes that this reflects:

> *APA has undergone upgrades of upstream compression at Young compressor station, which supports Culcairn injection capacity.*
>
> *The import capacity is reduced if Uranquinty Power station is operating, or if there is high system demand off the Young to Culcairn lateral.*

This aligns with information provided by APA which indicated that a further 25TJ/d capacity from Young NSW into Victoria on the Victorian NSW Interconnect, on top of the existing 170TJ/day southern haulage capacity[48].

It is our understanding that further augmentations are available, including:

- Adding additional compressor stations, increasing the total capacity south of Young to Culcairn to 220TJ/day (plus an additional 80TJ/day to Uranquinty); and
- With NSW looping and additional compressors (including on the Victorian side), southbound capacity can be increased beyond that as needs require before additional Vic expansion would be required beyond about 400 TJ/day.

Whilst we have not assessed the detailed costs of this potential solution, this solution has the conceptual advantage:

- Of unlocking the full additional south bound capacity that is created by APA's expansion of the SWQP/MSP, noting that absent an investment such as this in additional north/south transmission capacity, AEMO's GSOO indicates that flows south bound on the EGP and Interconnect are at their capacity for a significant proportion of the year;
- Of potentially accommodating more, valuable, flexible seasonal "shaped" gas supplies, to be transported from the larger, more prospective markets outside of Victoria, to help cover monthly winter demand, not just extreme peaks; and
- Of being incremental and flexible, which means its funding is not reliant on the AER accepting the medium to long term forecast needs of the Victorian market, rather the market is able to respond (via contracting for solutions) closer to when the asset may in fact be needed, enabling more (and better) information as to the forecast supply / demand balance in Victoria to be revealed.

4.4. Other options

4.4.1. Augment Dandenong LNG

The following figure highlights the amount of gas that has been injected from the Dandenong LNG (DLNG) facility into the VTS over recent years.

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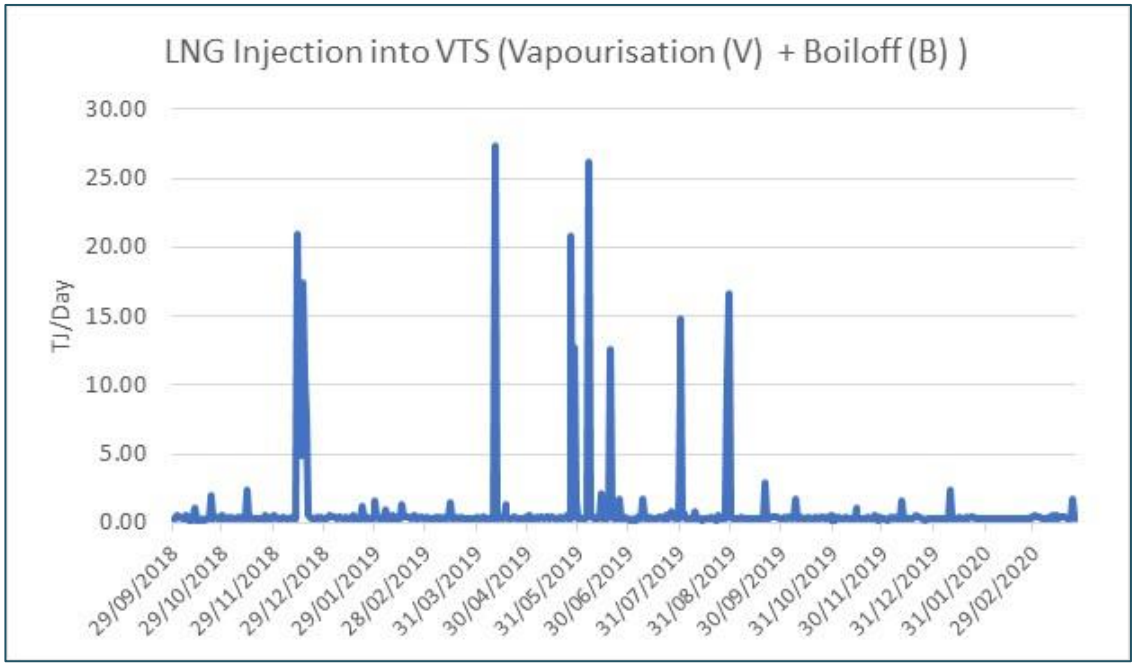
47 AEMO, *2021 Victorian Gas Planning Report*, page 71

48 https://www.apa.com.au/globalassets/our-services/gas-transmission/east-coast-grid/moomba-sydney-pipeline/msp-diagram.pdf (page 2)

Table 9 of AEMO's GSOO indicates that the DLNG can deliver up to 87 TJ/day into the Victorian system, and can hold up to 10 days' supply at this rate.

Figure 21: Dandenong LNG Injections into VTS



Source: OGW analysis of GBB information

As can be seen from the above graph, there has been very limited reliance placed on this facility over the last 2 years. In its VGPR, AEMO noted that[49]:

> *The contracted storage Dandenong LNG storage inventory has declined to only 80 TJ, which is 12% of its 680TJ capacity. The 4.5 TJ/hr of injection capacity from winter 2021 is less than the firm capacity of 5.5 TJ/hr.*
>
> *Due to reduced contracted levels, AEMO's ability to manage the DTS during peak winter demand is severely impacted, which increases the risk of gas curtailment in the DTS if peak shaving LNG is not available at firm rates of 5.5 TJ/hr.*

Notwithstanding this, we note that in key parts of the analysis AEMO presents in its 2021 GSOO (e.g., Figure 28 of AEMO's report, reproduced as Figure 1 in this report), the DLNG facility is assumed to be fully maximised.[50] Therefore, this facility cannot be assumed to be relied upon more in order to bridge any supply gap, based on its current operational parameters.

We haven't undertaken a detailed assessment of the specific costs or feasibility of augmenting the DLNG facility to increase its ability to provide additional peak day support to the Victorian DWGM. Whilst this is potentially feasible, its economic viability depends on, amongst other things, the probability that multiple supply gaps occur in a year. The fewer, or less frequent are these supply gaps, the more feasible an augmentation solution might become. The overall contracting of this facility also does not point easily to augmentation capital being viable.

49 AEMO, *2021 Victorian Gas Planning Report*, page 10

50 AEMO, *2021 Gas Statement of Opportunities*, Footnote 7

4.4.2. Demand-side response

Everything else being equal, the lower the probability of there being a gap between available supply and demand, the more likely it is that demand response could be the most economic means of balancing supply and demand. Demand response could be enabled by:

- A market-price induced demand response; or
- A centralised, demand side response mechanism that incentivises customer to provide demand response to the market[51].

The ability to rely on the former depends on a range of factors, including the potential price that might be induced by any supply/demand imbalance; customers' elasticity of demand;[52] and importantly, whether customers are in fact exposed to wholesale (spot) prices (or whether they have in fact contracted that exposure away, by entering into long-term take-or pay contracts with retailers). It is our understanding that most gas that is sold in the DWGM is sold under longer-term take-or-pay contracts, hence we place limited weight on this approach[53].

Similarly, there is currently no centralised demand side response mechanism for the Victorian Gas Market, which means that on present policy and market settings, this approach could not be relied upon to potentially assist in managing a peak day supply/demand imbalance. We note though that the ultimate response to excessive peak demand will inevitably be curtailment by the AEMO as the System Operator.

4.5. What options are likely to be the economically attractive, in light of the uncertainty around future gas market conditions?

As AEMO states in its 2021 GSOO[54]:

> *AEMO has demonstrated in this 2021 GSOO:*
>
> *• Additional peak management solutions, pipeline expansions or anticipated field development ahead of winter 2023 would help minimise risk of unplanned disruption in southern regions under certain conditions in the event PKGT's construction or commissioning schedule is delayed.*
>
> *• In the following years, while consumption may decline under some scenarios, peak and seasonal demands are forecast to continue to grow with growing customer connections, and GPG may amplify seasonal consumption patterns with shifts from summer to winter peaking. This uncertainty increases the value of flexible supply and infrastructure options to meet projected seasonal supply gaps.*

We are in complete agreement with AEMO in relation to the impact that this uncertainty has on the value that should be ascribed to flexible supply and infrastructure options.

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51 This could be further refined to incentivise demand response e.g., located in specific areas

52 Which will be affected by a range of unique factors that they face at that specific time, for example, for a gas-fired power station, their contractual position and/or the value of electricity production foregone, if they were to reduce their gas consumption in response to the gas price.

53 Although this may change in the future, if more customers move to contractual arrangements that expose them wholesale gas prices.

54 AEMO, *2021 Gas Statement of Opportunities*, page 9

Conceptually, a 'real options' analytical framework is ideally suited to undertake analysis in this type of uncertain environment. A 'real options' framework essentially represents a sophisticated probabilistic planning approach that can be used to assess the optimality of various options for balancing supply and demand. It explicitly recognises the trade-off between the value of flexibility and scale efficiency of supply and demand side options, having regard to the entire range of future events, and the ability of a modelled supply portfolio to be able to respond to that range of future events.

It explicitly quantifies the value of making decisions over time as would be the case in real life, rather than assuming perfect foresight. These decisions may involve higher costs in the short term, but lead to long term benefits.

Whilst we have not undertaken a detailed real options analysis for the purposes of this project, the concepts are applicable, and if applied, to our mind, lead to a small set of potentially attractive solutions being up for consideration at this stage, namely:

- Increased compression on the VN Interconnect (noting that this would be a market-led solution, and hence not directly related to APA's VTS AA), or
- Increased compression on the SWP, up to the capacity already constructed and contracted for by Iona.

The LNG import options may also prove to be attractive, the test will be whether they can reach FID; until such time, our assumption is that more marginal investments are likely to be more attractive to the market, given the uncertain investment environment.

4.5.1. Conclusions

Assuming that the PKGT reaches FID, the market – one where there are numerous sophisticated market participants – will have contracted in such a way as to materially reduce the uncertainty of gas supply for Victoria, despite the solution being outside of the (regulated) VTS.

Beyond this, our preliminary position is that unless the Iona injection capacity into the SWP is fully contracted long-term (i.e., the market has already revealed its need for, and preference of, this solution, relative to other available solutions), increased compression on the Interconnect (i.e., NSW side) between Young and Culcairn at low marginal investment costs is the solution that the market may be more likely to rely upon, given the current uncertainty affecting the gas market, as this solution has the conceptual advantage:

- Of unlocking the full additional south bound (peak) capacity that is created by APA's expansion of the SWQP/MSP, noting that absent an investment such as this in additional north/south transmission capacity, AEMO's GSOO indicates that flows south bound on the EGP and Interconnect are at their capacity for a significant proportion of the year;
- Of potentially accommodating more, valuable, flexible seasonal "shaped" gas supplies, to be transported from the larger, more prospective gas outside of Victoria, to help cover monthly winter demand, not just extreme peaks; and
- Of being incremental and flexible, which means its funding is not reliant on the AER accepting the medium to long term forecast needs of the Victorian market, rather the market is able to respond (via contracting for solutions) closer to when the asset may in fact be needed, enabling more (and better) information as to the forecast supply / demand balance in Victoria to be revealed.

To our mind, there is also a case for policymakers to consider introducing a market mechanism that would allow demand side participation in the peak of winter to assist in managing the risks of small excess peak demand excursions. This would likely be a very low-cost (and flexible) solution to managing transitional issues and uncertainty, and mimics what has been occurring in the National Electricity Market (NEM).

Given the uncertainty as to what future (peak and annual) demands will be placed on the Victorian gas transmission network over the next 5-10 years (and beyond), and the fact that there appears to be a feasible alternative market-led solution to addressing peak day demand issues, we see little justification to support APA lodging a capital expenditure forecast that involves looping any part of the SWP to accommodate increased supply from either or both of the two LNG import facilities in Victoria, whilst also maintaining Iona's existing capacity to provide gas on peak days.

This is not to say that the market may not facilitate the development of these (FSRU) supply solutions over the period of APA's next AA; it may be that the market values their ability to alleviate any shortfall in annual or seasonal gas requirements in Victoria, whilst providing some increase in peak day support (relative to existing levels), in lieu of relying on Iona. If this were to occur, it would demonstrate that the market is in effect, seeking to reallocate how the existing SWP pipeline capacity is utilised.

5. Long-term impact on APA

5.1.1. Objective of this section

Despite APA's AA period only being for 5 years, longer-term forecasts have implications for both investment proposals as well as argumentations, regarding the valid economic lives that should be applied to APA's assets (which in turn is linked to any assessment as to whether or not APA has a valid claim to accelerate depreciation on the VTS to ensure it can recover the value of the invested capital over the remaining life).

The objective of this section is to discuss the longer-term implications for APA related to the issues discussed in the previous sections, in particular, we elaborate on the implications for APA and the recovery of their existing asset base via regulatory depreciation charges.

These issues under the regulatory regime applying to the VTS also have implications for all customers supplied by that system.

5.1.2. Regulatory depreciation

Reference tariffs for an access arrangement are calculated from the total of the costs expected to be incurred by an efficient service provider. These costs – a business' Required Revenue Requirement - are made up of:

- Return on capital.
- Regulatory depreciation (return of capital).
- Operating expenditure.
- Incentive mechanisms.
- Benchmark tax allowance.

Regulatory depreciation is the cost component that provides for the service provider's up-front investment to be returned to it - via tariffs - over time. Decisions around regulatory depreciation are ostensibly timing decisions – that is, they affect the timing of cashflows, rather than the overall amount of money the regulated business receives in NPV terms.

5.1.3. Rules related to the regulatory depreciation

Rule 88 of the National Gas Rules (Depreciation schedule) requires that:

> *(1) The depreciation schedule sets out the basis on which the pipeline assets constituting the capital base are to be depreciated for the purpose of determining a reference tariff.*
>
> *(2) The depreciation schedule may consist of a number of separate schedules, each relating to a particular asset or class of assets.*

Rule 89 (Depreciation criteria) requires that:

(1) The depreciation schedule should be designed:

> *(a) so that reference tariffs will vary, over time, in a way that promotes efficient growth in the market for reference services; and*
>
> *(b) so that each asset or group of assets is depreciated over the economic life of that asset or group of assets; and*
>
> *(c) so as to allow, as far as reasonably practicable, for adjustment reflecting changes in the expected economic life of a particular asset, or a particular group of assets; and*

(d) so that (subject to the rules about capital redundancy), an asset is depreciated only once (ie that the amount by which the asset is depreciated over its economic life does not exceed the value of the asset at the time of its inclusion in the capital base (adjusted, if the accounting method approved by the AER permits, for inflation)); and

(e) so as to allow for the service provider's reasonable needs for cash flow to meet financing, non-capital and other costs.

(2) Compliance with subrule (1)(a) may involve deferral of a substantial proportion of the depreciation, particularly where:

(a) the present market for pipeline services is relatively immature; and

(b) the reference tariffs have been calculated on the assumption of significant market growth; and

(c) the pipeline has been designed and constructed so as to accommodate future growth in demand.

In our opinion, the Rules clearly provide a regulated gas business with the flexibility to propose changes to it forecast depreciation schedule to reflect, amongst other things, changes in the:

- Market for its reference services: and
- Economic life of the asset or group of assets that are used to provide its reference services.

In this context, and as explained in some detail in the body of this report, the:

- **Market for APA's reference services – being gas transmission services – could potentially change in the future**: To our mind, the combined effect of:
  - The Victorian Government setting a legislated Net Zero target for 2050;
  - The Victorian Government setting targets to reduce the State's greenhouse gas emissions from 2005 levels by 28-33% by 2025 and 45-50% by 2030"; and that
  - The Victorian Government having launched a detailed 'Gas Substitution Roadmap', which will "*detail the transition pathways and identify policy mechanisms to achieve Victoria's emissions reduction targets through reduced fugitive emissions, more efficient use of gas, electrification and increased use of alternative gases such as hydrogen and biogas",* and noting that each of the key decarbonisation pathways – electrification, more efficient use of gas and the increased use of renewable gases – will likely reduce the use of the gas transmission system,
  - AEMO's clear statement in its IASR regarding how it plans to model a Net Zero 2050 scenario in the future; and
  - Our modelling of the potential impact on demand on the VTS[55],

  highlights a potential risk to the market for APA's reference services.

55 Including the more detailed forecasts that are provided in the Addendum to this report.

- **Economic life of APA's transmission assets would shorten:** The economic life, which reflects the expected period of time during which an asset or group of asset remains useful to the average owner, reflects the market for the services that are, or could potentially be provided by that asset. In the context of APA's assets, for the reasons outlined above, the market for (natural) gas transmission services might decline over time, everything else being equal, impacting upon their economic life, unless of course those assets are able to be re-purposed and used to provide alternative (regulated) services. Clearly, one possibility is that APA's assets may be able to be utilised to move renewable gases such as hydrogen, synthetic methane and biogas. Whilst this is a possibility, it is also possible that the production and distribution of renewable gases will be either: (a) conducted via distributed facilities, likely connected directly into distribution networks or (b) via new, bespoke pipelines, connecting new sources of supply (not otherwise in close proximity to APA's existing gas transmission infrastructure, and potentially facilitating connection into the distribution network).

More certainty on this issue will be provided over time, which in theory, could be used to inform a revised assessment of APA's economic life in the future[56].

However, what the National Gas Rules (Rules) don't address is the nuanced consideration of the probability and timing of any issue that might affect the future market for APA's reference services or when the economic life of APA's transmission assets might reduce. Put another way, it doesn't explicitly address the balance that needs to be found between ensuring assets are correctly depreciated over their economic life, moving too early or too late to accelerate depreciation, and ensuring price changes are reasonable. Presumably, the AER would need to consider these issues in the context of the National Gas Objective (s23 of the NGL), which is:

> *The objective of this Law is to promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas.*

5.1.4. Regulatory Precedence

As part of its Dampier to Bunbury Pipeline (DBP) decision, the Economic Regulatory Authority (ERA) considered DBP's request to bring forward the projected end of the pipeline's economic life from 2090 to 2063.

A significant amount of information and supporting evidence was presented in this case, around issues such as[57]:

- The estimated year in which it expected that regulated tariffs for natural gas would achieve parity with alternative technologies (which was 2063, based on modelling results that indicated that this was when the DBP would need to charge a "*negative transport price for gas, which is deemed to be when the DBNGP can no longer earn revenue from transporting gas and hence will stop transporting activities rather than earn negative revenues*"[58]);
- The estimated depreciation amounts in future AAs; and
- The estimated impact on tariffs.

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56 For example, there is nothing in the Rules to suggest that if APA's forecast depreciation schedule was adjusted to reflect assumptions regarding a shorter economic life as a result of a declining market for natural gas, that this could not be adjusted as part of a future AA, if new information came to light that indicated APA's transmission assets could be repurposed to provide renewable gases.

57 For the avoidance of doubt, we have not been asked to undertake this type of analysis as part of this scope of work.

58 ERA, *Final decision on proposed revisions to the Dampier to Bunbury Natural Gas Pipeline access arrangement 2021 to 2025 - Submitted by DBNGP (WA) Transmission Pty Ltd,* page 333

As part of that assessment, the ERA considered concerns and stakeholder submissions that touched on varied issues such as:

- Whether the Rules envisaged that assets (or classes of assets) could have their remaining lives adjusted over time to better align them with their economic lives and promote efficient growth in the market for reference services;
- Whether or not it was too early to commence accelerated depreciation (with some stakeholders arguing that it was 'too early' to 'consider climate change' or 'because of the uncertainty'); and
- How to balance the needs between ensuring assets are correctly depreciated over their economic life and ensuring price changes are reasonable.

Having regard to all the evidence presented, in its Final Decision, the ERA approved DBP's request to bring forward the projected end of the pipeline's economic life from 2090 to 2063.

5.1.5. Our opinion as to whether there is a case under the Rules for APA to request accelerated depreciation

Prima facie, we think there is scope under the Rules for APA to seek the AER's consideration of an accelerated depreciation schedule for the assets that it uses to provide gas transmission (reference) services in Victoria. Such an outcome has regulatory precedence is aligned to the Rules, as in our opinion, the Rules clearly provide a regulated gas business with the flexibility to propose changes to it forecast depreciation schedule to reflect, amongst other things, changes in the:

- Market for its reference services: and
- Economic life of the asset or group of assets that are used to provide its reference services.

As outlined earlier, we are also of the opinion that there are a number of potential risks to the **market** for APA's current reference services, any of which could start to manifest in the short term, but with a higher probability of manifesting in the medium to long-term. These could affect the economic life of APA's assets.

Appendix A: Potential impact on future gas loads in Victoria

A.1: Objective of additional scope of work

Subsequent to being asked to complete the scope of work addressed in the main body of this report, APA asked us to prepare a high level load and demand forecast.

These forecasts were to:

- Reflect our best estimate of the likely gas loads to 2035;
- Reflect the information from the main body of our report, and any updated AEMO assumptions / information that were relevant; and
- Be at the system withdrawal zone (SWZ) level, hence forecasts have been produced for: Ballarat, Geelong, Gippsland, Melbourne, Northern and Western SWZs.

The resulting forecasts therefore reflect the factors that we have outlined in the main body of the report, being:

- Changes related to Altona and Qenos;
- The progressive electrification of residential gas heating loads between now and 2035; and
- The potential impact of (distributed-connected) renewable gas substituting natural gas.

We have produced forecasts for both:

- Peak day demand (1 in 20 TJ/day); and
- Overall gas demand (PJ).

We have also attempted to compare the resultant peak day demand needs in Victoria to sources of peak day supply.

A.2: Caveats

The caveats presented in the main body of our report also apply to the work presented in this Appendix. In particular, we would note that:

- In order to complete this task, we considered, and in many cases relied on, publicly available information. We have taken much of this information on face value, and to the extent it is incorrect, the conclusions drawn from that information may also be incorrect.
- Given the nature of the forecasts and uncertainty around the relevant policies that may be enacted in Victoria in order to achieve their legislated 2050 Net Zero targets, it has been necessary to make a number of assumptions and to draw conclusions from a number of different information sources, particularly regarding the potential impact of electrification.

The forecasts and conclusions contained in this report need to be considered in this light.

A.3: Our methodology for estimating the impact of changes affecting gas demands at each of Victoria's Six System Withdrawal Zones (SWZ)

We were asked to produce forecasts at the 6 system withdrawal zones (Ballarat, Geelong, Gippsland, Melbourne, Northern and Western).

To establish starting levels of gas consumption across the 6 zones, we have relied upon information contained in the VGPR, which breaks down AEMO's forecasts of gas consumption to 2025 at this level, by customer class (i.e., Tariff V and Tariff D). These forecasts are reproduced in the next section.

After establishing the starting point gas usages (to 2025) for each SWZ, we have then:

- Proportioned our Statewide estimated reductions in peak demand resulting from electrifying residential heating loads by allocating those reductions across:
  - AEMO's forecast Tariff V customer usage in each year to 2025, as per Table 29 of the VGPR;
  - Our forecast of Tariff V customer usage between 2025 and 2030, with this forecast derived by proportioning AEMO's forecast of each SWZ's 2025 Tariff V usage by AEMO's forecast annual growth rate in Victoria's 1-in-20 maximum demand, which we have derived from Table 4 of AEMO's 2021 GSOO[59]; and
  - Our forecast of Tariff V consumption between 2030 and 2035, with our assumption being that this will not change over this period under the BAU case. We acknowledge that this assumption differs to AEMO, who in fact forecast an increase in 1-in-20 peak demand between 2030 and 2040 (again, in Table 4 of AEMO's 2021 GSOO), however we believe our (relatively) conservative approach is reasonable, given the purpose of this analysis.
- Adopted a similar approach to what is described above to allocate the estimated reductions on total gas usage across the SWZ's;
- Allocated our estimates of the reduction in peak and annual demand associated with the closure of the Altona refinery and reduced gas consumption of Qenos (based on the approach discussed in the main body of this report), to the Melbourne SWZ; and
- Allocated our estimate of the potential increase in the use of renewable gases in each forecast year to each SWZ based on the proportion of the total forecast gas demands (so Tariff V and Tariff D) consumed at that SWZ. Again, the forecast is discussed in the main body of this report, and assumes that renewable gases are injected at a distribution level (thus avoiding the transmission system).

A.4: AEMO's original 2021 VGPR Forecasts for each SWZ

The following figures reproduce the key information that is contained in AEMO's 2021 VGPR forecasts that we have used for the purposes of establishing our starting point gas usages (to 2025) for each SWZ. These are:

- Annual system consumption by SWZ (Tariff V and D split) (PJ/yr);
- Annual 1-in-20 peak daily demand by SWZ (TJ/day); and

59 We are unable to determine whether the growth in peal demand between 2025 and 2030 is driven by Tariff V or Tariff D customers, hence we have assumed that same growth rate for the two groups of customers between 2025 and 2030, such that total forecast demand equates to what is presented in the GSOO for 2030.

- Annual 1-in-20 DTS and non-DTS peak day demand forecast (TJ/day).

This information is the most current, detailed information available regarding what AEMO forecast gas consumption to be in the VTS out to 2025.

Figure 22: Annual system consumption by SWZ (Tariff V and D split) (PJ/yr)

Table 18 Annual system consumption by SWZ (Tariff V and D split) (PJ/y)

SWZ		2021	2022	2023	2024	2025	Change over outlook
Ballarat	Tariff V	8.9	9.0	9.0	9.0	9.2	2.9%
	Tariff D	1.7	1.6	1.6	1.6	1.6	-8.9%
	SWZ total	**10.6**	**10.6**	**10.6**	**10.6**	**10.7**	**1.0%**
Geelong	Tariff V	11.5	11.6	11.6	11.6	11.7	1.5%
	Tariff D	9.1	9.1	8.9	8.8	8.6	-4.5%
	SWZ total	**20.6**	**20.6**	**20.4**	**20.3**	**20.3**	**-1.2%**
Gippsland	Tariff V	5.9	5.9	5.9	6.0	6.0	2.9%
	Tariff D	8.1	7.9	7.7	7.4	7.1	-12.2%
	SWZ total	**14.0**	**13.8**	**13.6**	**13.4**	**13.2**	**-5.8%**
Melbourne	Tariff V	92.2	90.5	88.5	86.7	85.6	-7.2%
	Tariff D	35.5	35.3	34.9	34.5	33.9	-4.5%
	SWZ total	**127.7**	**125.8**	**123.4**	**121.2**	**119.5**	**-6.4%**
Northern	Tariff V	1.3	1.3	1.3	1.3	1.3	-1.1%
	Tariff D	2.7	2.7	2.7	2.7	2.7	0.9%
	SWZ total	**4.0**	**4.0**	**4.0**	**4.0**	**4.0**	**0.2%**
Western	Tariff V	11.3	11.3	11.3	11.3	11.4	0.3%
	Tariff D	8.6	8.7	8.7	8.6	8.5	-1.9%
	SWZ total	**20.0**	**20.1**	**20.0**	**19.9**	**19.8**	**-0.6%**

Source: AEMO, *2021 Victorian Gas Planning Report*, page 76

Figure 23: Annual 1-in-20 peak daily demand by SWZ (TJ/day)

Table 20 Annual 1-in-20 peak daily demand by SWZ (TJ/d)

SWZ		2021	2022	2023	2024	2025	Change over outlook
Ballarat	Tariff V	65.3	65.8	65.9	66.6	67.7	3.6%
	Tariff D	5.8	5.5	5.5	5.4	5.3	-8.5%
	SWZ total	**71.2**	**71.4**	**71.4**	**72.1**	**73.0**	**2.6%**
Geelong	Tariff V	86.5	87.0	86.8	87.4	88.4	2.2%
	Tariff D	39.0	39.1	38.0	37.9	37.4	-4.1%
	SWZ total	**125.5**	**126.1**	**124.8**	**125.3**	**125.8**	**0.2%**
Gippsland	Tariff V	45.4	45.8	45.8	46.3	47.0	3.6%
	Tariff D	28.5	27.8	26.9	26.1	25.1	-11.8%
	SWZ total	**73.9**	**73.6**	**72.8**	**72.4**	**72.2**	**-2.4%**
Melbourne	Tariff V	735.8	723.4	705.8	695.2	687.3	-6.6%
	Tariff D	127.1	126.1	124.5	123.5	121.9	-4.1%
	SWZ total	**863.0**	**849.5**	**830.3**	**818.7**	**809.2**	**-6.2%**
Northern	Tariff V	80.7	80.8	80.4	80.8	81.4	0.9%
	Tariff D	30.1	30.4	30.3	30.2	29.7	-1.4%
	SWZ total	**110.8**	**111.2**	**110.7**	**110.9**	**111.1**	**0.3%**
Western	Tariff V	9.4	9.4	9.3	9.3	9.3	-0.5%
	Tariff D	9.0	9.1	9.2	9.2	9.1	1.4%
	SWZ total	**18.4**	**18.5**	**18.5**	**18.5**	**18.5**	**0.4%**

Source: AEMO, *2021 Victorian Gas Planning Report*, page 77-78

Figure 24: Annual 1-in-20 DTS and non-DTS peak day demand forecast (TJ/day)

Table 23 Annual 1-in-20 non-DTS peak day demand forecast (TJ/d)

	2021	2022	2023	2024	2025	Change over outlook
Tariff V (non-DTS)	1.4	1.5	1.5	1.6	1.7	15.6%
Tariff D (non-DTS)	2.0	2.1	2.1	2.0	2.0	-1.0%
System demand non-DTS	3.5	3.6	3.6	3.7	3.7	5.8%
System demand DTS	1,262.8	1,250.2	1,228.5	1,217.9	1,209.8	-4.2%
System demand Victoria	1,266.3	1,253.7	1,232.1	1,221.5	1,213.5	-4.2%

Source: AEMO, *2021 Victorian Gas Planning Report*, page 79

A.5: Our adjustments to Peak Demand forecasts for each SWZ

The following table summarises our adjustments (highlighted grey) to the 1-in-20 peak demand (TJ/day) forecasts for each SWZ.

Table 9: Peak demand forecasts - Ballarat

Annual 1-in-20 peak daily demand by SWZ (TJ/day)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Tariff V - VGPR	65.30	65.80	65.90	66.60	67.70	68.17	68.64	69.11	69.59	70.07	70.07	70.07	70.07	70.07	70.07
Tariff V - Adj (Electrification)	-	-0.22	-0.66	-1.36	-2.31	-3.46	-5.07	-6.92	-9.22	-11.53	-13.84	-16.14	-18.45	-20.76	-23.06
Tariff D - Adj (Refinery and Qenos)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution Connected Renewable Gas	-	-	-0.18	-0.36	-0.55	-0.74	-0.92	-1.11	-1.29	-1.47	-1.66	-1.84	-2.03	-2.21	-2.40
Tariff D - VGPR	5.80	5.50	5.50	5.40	5.30	5.34	5.37	5.41	5.45	5.49	5.49	5.49	5.49	5.49	5.49
SWZ Total	**71.10**	**71.08**	**70.56**	**70.28**	**70.14**	**69.31**	**68.02**	**66.50**	**64.53**	**62.55**	**60.06**	**57.57**	**55.08**	**52.59**	**50.10**

Table 10: Peak demand forecasts - Geelong

Annual 1-in-20 peak daily demand by SWZ (TJ/day)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Tariff V - VGPR	86.50	87.00	86.80	87.40	88.40	89.01	89.63	90.25	90.87	91.50	91.50	91.50	91.50	91.50	91.50
Tariff V - Adj (Electrification)	-	-0.29	-0.88	-1.78	-3.01	-4.52	-6.63	-9.03	-12.05	-15.06	-18.07	-21.08	-24.09	-27.10	-30.11

Tariff D - Adj (Refinery and Qenos)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution Connected Renewable Gas	-	-	-0.31	-0.63	-0.95	-1.27	-1.59	-1.91	-2.22	-2.54	-2.86	-3.18	-3.49	-3.81	-4.13
Tariff D - VGPR	39.00	39.10	38.00	37.90	37.40	37.66	37.92	38.18	38.45	38.71	38.71	38.71	38.71	38.71	38.71
SWZ Total	**126**	**126**	**124**	**123**	**122**	**121**	**119**	**117**	**115**	**113**	**109**	**106**	**103**	**99**	**96**

Table 11: Peak demand forecasts - Gippsland

Annual 1-in-20 peak daily demand by SWZ (TJ/day)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Tariff V - VGPR	45.40	45.80	45.80	46.30	47.00	47.32	47.65	47.98	48.31	48.65	48.65	48.65	48.65	48.65	48.65
Tariff V - Adj (Electrification)	-	-0.15	-0.46	-0.94	-1.60	-2.40	-3.52	-4.80	-6.40	-8.01	-9.61	-11.21	-12.81	-14.41	-16.01
Tariff D - Adj (Refinery and Qenos)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution Connected Renewable Gas	-	-	-0.18	-0.36	-0.55	-0.73	-0.91	-1.09	-1.27	-1.46	-1.64	-1.82	-2.00	-2.18	-2.37
Tariff D - VGPR	28.50	27.80	26.90	26.10	25.10	25.27	25.45	25.62	25.80	25.98	25.98	25.98	25.98	25.98	25.98
SWZ Total	**73.90**	**73.45**	**72.06**	**71.10**	**69.95**	**69.47**	**68.67**	**67.71**	**66.44**	**65.17**	**63.38**	**61.60**	**59.82**	**58.03**	**56.25**

Table 12: Peak demand forecasts - Melbourne

Annual 1-in-20 peak daily demand by SWZ (TJ/day)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Tariff V - VGPR	736	723	706	695	687	692	697	702	707	711	711	711	711	711	711
Tariff V - Adj (Electrification)	-	-2.39	-7.12	-14.14	-23.41	-35.12	-51.51	-70.24	-93.65	-117.07	-140.48	-163.89	-187.30	-210.72	-234.13
Tariff D - Adj (Refinery and Qenos)	-7.24	-7.24	-7.24	-7.24	-7.24	-7.24	-7.24	-7.24	-7.24	-7.24	-7.24	-7.24	-7.24	-7.24	-7.24
Distribution Connected Renewable Gas	-	-	-2.06	-4.10	-6.13	-8.17	-10.21	-12.25	-14.30	-16.34	-18.38	-20.42	-22.47	-24.51	-26.55
Tariff D - VGPR	127	126	125	124	122	123	124	124	125	126	126	126	126	126	126
SWZ Total	**856**	**840**	**814**	**793**	**772**	**764**	**751**	**736**	**717**	**697**	**671**	**646**	**621**	**595**	**570**

Table 13: Peak demand forecasts - Northern

Annual 1-in-20 peak daily demand by SWZ (TJ/day)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Tariff V - VGPR	80.70	80.80	80.40	80.80	81.40	81.96	82.53	83.10	83.67	84.25	84.25	84.25	84.25	84.25	84.25
Tariff V - Adj (Electrification)	-	-0.27	-0.81	-1.64	-2.77	-4.16	-6.10	-8.32	-11.09	-13.86	-16.64	-19.41	-22.18	-24.96	-27.73
Tariff D - Adj (Refinery and Qenos)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution Connected Renewable Gas	-	-	-0.28	-0.56	-0.84	-1.12	-1.40	-1.68	-1.96	-2.24	-2.52	-2.80	-3.08	-3.36	-3.65

Tariff D - VGPR	30.10	30.40	30.30	30.20	29.70	29.91	30.11	30.32	30.53	30.74	30.74	30.74	30.74	30.74	30.74
SWZ Total	**111**	**111**	**110**	**109**	**107**	**107**	**105**	**103**	**101**	**99**	**96**	**93**	**90**	**87**	**84**

Table 14: Peak demand forecasts - Western

Annual 1-in-20 peak daily demand by SWZ (TJ/day)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Tariff V - VGPR	9.40	9.40	9.30	9.30	9.30	9.36	9.43	9.49	9.56	9.63	9.63	9.63	9.63	9.63	9.63
Tariff V - Adj (Electrification)	-	-0.03	-0.09	-0.19	-0.32	-0.48	-0.70	-0.95	-1.27	-1.58	-1.90	-2.22	-2.53	-2.85	-3.17
Tariff D - Adj (Refinery and Qenos)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution Connected Renewable Gas	-	-	-0.05	-0.09	-0.14	-0.19	-0.23	-0.28	-0.33	-0.37	-0.42	-0.46	-0.51	-0.56	-0.60
Tariff D - VGPR	9.00	9.10	9.20	9.20	9.10	9.16	9.23	9.29	9.35	9.42	9.42	9.42	9.42	9.42	9.42
SWZ Total	**18.40**	**18.47**	**18.36**	**18.22**	**17.94**	**17.87**	**17.73**	**17.56**	**17.32**	**17.09**	**16.73**	**16.36**	**16.00**	**15.64**	**15.27**

Table 15: Peak demand forecasts - Total

Annual 1-in-20 peak daily demand by SWZ (TJ/day)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Tariff V - VGPR	1,023	1,012	994	986	981	988	995	1,002	1,009	1,015	1,015	1,015	1,015	1,015	1,015
Tariff V - Adj (Electrification)	-	-3.34	-10.03	-20.05	-33.42	-50.13	-73.53	-100.26	-133.69	-167.11	-200.53	-233.95	-267.37	-300.79	-334.21
Tariff D - Adj (Refinery and Qenos)	-7.24	-7.24	-7.24	-7.24	-7.24	-7.24	-7.24	-7.24	-7.24	-7.24	-7.24	-7.24	-7.24	-7.24	-7.24
Distribution Connected Renewable Gas	-	-	-3.05	-6.11	-9.16	-12.21	-15.26	-18.32	-21.37	-24.42	-27.48	-30.53	-33.58	-36.63	-39.69
Tariff D - VGPR	240	238	234	232	229	230	232	233	235	237	237	237	237	237	237
SWZ Total	**1,255**	**1,240**	**1,208**	**1,185**	**1,160**	**1,148**	**1,130**	**1,109**	**1,081**	**1,053**	**1,017**	**980**	**944**	**907**	**871**

The table directly above indicates that in total, peak demand could reduce from a forecast 1252 TJ/day in 2035 to 871TJ/day, if we saw (amongst other things) a significant (50%) electrification of residential heating load by 2035. In the main body of the report, we assess what this means for the supply / demand balance in the southern markets, using AEMO's GSOO data, for years 2025 and 2030.

In a Victorian context, the 2035 forecast of 871TJ/day could theoretically[60] be accommodated by a combination of withdrawals from gas storage (Iona and the Dandenong LNG) and the transportation of gas from northern markets. This assumes that ~465TJ/day can be withdrawn from Iona, reflecting the capacity of the SWP (which is less than Iona's actual withdrawal capacity), 87TJ/day can be withdrawn from the Dandenong LNG facility, and 395TJ/day can be transferred south via the VNI and EGP.

60 For the avoidance of doubt, this is a simplified analysis; the actual availability of gas will be a function of many factors, including the amount of gas that is available to be withdrawn from storage on those peak demand days. This may be different to the maximum withdrawal/throughput capacities.

A.6: Our adjustments to Annual Demand forecasts for each SWZ

The following table summarises our adjustments (highlighted grey) to annual demand (PJ) forecasts for each SWZ.

Table 16: Annual demand forecasts - Ballarat

Annual demand by SWZ (PJ)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Tariff V - VGPR	8.90	9.00	9.00	9.00	9.20	9.24	9.27	9.31	9.34	9.38	9.38	9.38	9.38	9.38	9.38
Tariff V - Adj (Electrification)	-	-0.02	-0.06	-0.13	-0.22	-0.32	-0.47	-0.65	-0.86	-1.08	-1.29	-1.51	-1.72	-1.94	-2.15
Tariff D - Adj (Refinery and Qenos)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution Connected Renewable Gas	-	-	-0.03	-0.05	-0.08	-0.10	-0.13	-0.16	-0.19	-0.22	-0.25	-0.28	-0.31	-0.34	-0.37
Tariff D - VGPR	1.70	1.60	1.60	1.60	1.60	1.61	1.61	1.62	1.62	1.63	1.63	1.63	1.63	1.63	1.63
SWZ Total	**10.60**	**10.58**	**10.51**	**10.42**	**10.51**	**10.42**	**10.28**	**10.12**	**9.92**	**9.72**	**9.47**	**9.23**	**8.98**	**8.73**	**8.49**

Table 17: Annual demand forecasts - Geelong

Annual demand by SWZ (PJ)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Tariff V - VGPR	11.50	11.60	11.60	11.60	11.70	11.75	11.79	11.84	11.88	11.93	11.93	11.93	11.93	11.93	11.93
Tariff V - Adj (Electrification)	-	-0.03	-0.08	-0.16	-0.27	-0.41	-0.60	-0.82	-1.09	-1.37	-1.64	-1.91	-2.19	-2.46	-2.74

Tariff D - Adj (Refinery and Qenos)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution Connected Renewable Gas	-	-	-0.05	-0.10	-0.15	-0.19	-0.24	-0.29	-0.35	-0.40	-0.46	-0.52	-0.58	-0.64	-0.69
Tariff D - VGPR	9.10	9.10	8.90	8.80	8.60	8.63	8.67	8.70	8.73	8.77	8.77	8.77	8.77	8.77	8.77
SWZ Total	**20.60**	**20.67**	**20.37**	**20.14**	**19.88**	**19.77**	**19.61**	**19.42**	**19.17**	**18.92**	**18.59**	**18.26**	**17.93**	**17.59**	**17.26**

Table 18: Annual demand forecasts - Gippsland

Annual demand by SWZ (PJ)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Tariff V - VGPR	5.90	5.90	5.90	6.00	6.00	6.02	6.05	6.07	6.09	6.12	6.12	6.12	6.12	6.12	6.12
Tariff V - Adj (Electrification)	-	-0.01	-0.04	-0.08	-0.14	-0.21	-0.31	-0.42	-0.56	-0.70	-0.84	-0.98	-1.12	-1.26	-1.40
Tariff D - Adj (Refinery and Qenos)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution Connected Renewable Gas	-	-	-0.03	-0.06	-0.09	-0.12	-0.16	-0.19	-0.22	-0.26	-0.30	-0.34	-0.37	-0.41	-0.45
Tariff D - VGPR	8.10	7.90	7.70	7.40	7.10	7.13	7.15	7.18	7.21	7.24	7.24	7.24	7.24	7.24	7.24
SWZ Total	**14.00**	**13.79**	**13.53**	**13.25**	**12.87**	**12.82**	**12.74**	**12.64**	**12.52**	**12.39**	**12.22**	**12.04**	**11.86**	**11.68**	**11.50**

Table 19: Annual demand forecasts - Melbourne

Annual demand by SWZ (PJ)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Tariff V - VGPR	92.20	90.50	88.50	86.70	85.60	85.93	86.26	86.59	86.93	87.26	87.26	87.26	87.26	87.26	87.26
Tariff V - Adj (Electrification)	-	-0.20	-0.61	-1.21	-2.00	-3.00	-4.40	-6.00	-8.01	-10.01	-12.01	-14.01	-16.01	-18.01	-20.01
Tariff D - Adj (Refinery and Qenos)	-2.28	-2.28	-2.28	-2.28	-2.28	-2.28	-2.28	-2.28	-2.28	-2.28	-2.28	-2.28	-2.28	-2.28	-2.28
Distribution Connected Renewable Gas	-	-	-0.30	-0.58	-0.85	-1.14	-1.43	-1.73	-2.05	-2.38	-2.72	-3.06	-3.41	-3.75	-4.09
Tariff D - VGPR	35.50	35.30	34.90	34.50	33.90	34.03	34.16	34.29	34.43	34.56	34.56	34.56	34.56	34.56	34.56
SWZ Total	**125.42**	**123.32**	**120.21**	**117.13**	**114.36**	**113.54**	**112.31**	**110.87**	**109.02**	**107.16**	**104.82**	**102.47**	**100.12**	**97.78**	**95.44**

Table 20: Annual demand forecasts - Northern

Annual demand by SWZ (PJ)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Tariff V - VGPR	1.30	1.30	1.30	1.30	1.30	1.31	1.31	1.32	1.32	1.33	1.33	1.33	1.33	1.33	1.33
Tariff V - Adj (Electrification)	-	-0.00	-0.01	-0.02	-0.03	-0.05	-0.07	-0.09	-0.12	-0.15	-0.18	-0.21	-0.24	-0.27	-0.30
Tariff D - Adj (Refinery and Qenos)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution Connected Renewable Gas	-	-	-0.01	-0.02	-0.03	-0.04	-0.05	-0.06	-0.07	-0.08	-0.09	-0.10	-0.11	-0.13	-0.14
Tariff D - VGPR	2.70	2.70	2.70	2.70	2.70	2.71	2.72	2.73	2.74	2.75	2.75	2.75	2.75	2.75	2.75

SWZ Total	**4.00**	**4.00**	**3.98**	**3.96**	**3.94**	**3.93**	**3.92**	**3.90**	**3.87**	**3.85**	**3.80**	**3.76**	**3.72**	**3.68**	**3.64**

Table 21: Annual demand forecasts - Western

Annual demand by SWZ (PJ)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Tariff V - VGPR	11.30	11.30	11.30	11.30	11.40	11.44	11.49	11.53	11.58	11.62	11.62	11.62	11.62	11.62	11.62
Tariff V - Adj (Electrification)	-	-0.03	-0.08	-0.16	-0.27	-0.40	-0.59	-0.80	-1.07	-1.33	-1.60	-1.87	-2.13	-2.40	-2.67
Tariff D - Adj (Refinery and Qenos)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Distribution Connected Renewable Gas	-	-	-0.05	-0.10	-0.14	-0.19	-0.24	-0.29	-0.34	-0.40	-0.45	-0.51	-0.57	-0.63	-0.68
Tariff D - VGPR	8.60	8.70	8.70	8.60	8.50	8.53	8.57	8.60	8.63	8.67	8.67	8.67	8.67	8.67	8.67
SWZ Total	**19.90**	**19.97**	**19.87**	**19.65**	**19.49**	**19.39**	**19.23**	**19.04**	**18.80**	**18.56**	**18.24**	**17.91**	**17.59**	**17.26**	**16.94**

Table 22: Annual demand forecasts - Total

Annual demand by SWZ (PJ)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Tariff V - VGPR	131.10	129.60	127.60	125.90	125.20	125.68	126.17	126.65	127.14	127.63	127.63	127.63	127.63	127.63	127.63
Tariff V - Adj (Electrification)	-	-0.29	-0.88	-1.76	-2.93	-4.39	-6.44	-8.78	-11.71	-14.64	-17.56	-20.49	-23.42	-26.34	-29.27

Tariff D - Adj (Refinery and Qenos)	-2.28	-2.28	-2.28	-2.28	-2.28	-2.28	-2.28	-2.28	-2.28	-2.28	-2.28	-2.28	-2.28	-2.28	-2.28
Distribution Connected Renewable Gas	-	-	-0.46	-0.91	-1.34	-1.79	-2.25	-2.72	-3.22	-3.74	-4.26	-4.80	-5.36	-5.89	-6.42
Tariff D - VGPR	65.70	65.30	64.50	63.60	62.40	62.64	62.88	63.12	63.37	63.61	63.61	63.61	63.61	63.61	63.61
SWZ Total	**194.52**	**192.33**	**188.48**	**184.55**	**181.05**	**179.87**	**178.08**	**176.00**	**173.30**	**170.59**	**167.14**	**163.67**	**160.19**	**156.73**	**153.27**

As discussed in the main body of the report, the reduction in overall gas demand resulting from the above interventions does not alleviate the shortfall AEMO's is projecting in southern markets in the later part of the decade (and beyond).

A.7: Final forecasts for APA's AA period

The following table summarises our 1-in-20 peak demand (TJ/day) forecasts for each SWZ for APA's AA period.

Table 23: Peak demand forecasts - Total (TJ/day)

SWZ	Annual 1-in-20 peak daily demand by SWZ (TJ/day)	2023	2024	2025	2026	2027
Ballarat	Tariff V	65.07	64.91	64.88	64.03	62.71
	Tariff D	5.49	5.37	5.26	5.28	5.31
	SWZ Total	**70.56**	**70.28**	**70.14**	**69.31**	**68.02**
Geelong	Tariff V	85.71	85.18	84.72	83.60	81.89
	Tariff D	37.91	37.71	37.12	37.28	37.45
	SWZ Total	**123.61**	**122.89**	**121.84**	**120.88**	**119.33**
Gippsland	Tariff V	45.22	45.13	45.04	44.45	43.54
	Tariff D	26.83	25.97	24.91	25.02	25.13
	SWZ Total	**72.06**	**71.10**	**69.95**	**69.47**	**68.67**
Melbourne	Tariff V	696.93	677.57	658.68	649.99	636.66
	Tariff D	116.95	115.64	113.74	114.27	114.81
	SWZ Total	**813.88**	**793.21**	**772.42**	**764.27**	**751.47**
Northern	Tariff V	79.39	78.75	78.01	76.98	75.40
	Tariff D	30.22	30.05	29.48	29.61	29.74
	SWZ Total	**109.61**	**108.80**	**107.49**	**106.59**	**105.14**
Western	Tariff V	9.18	9.06	8.91	8.80	8.61
	Tariff D	9.18	9.15	9.03	9.07	9.11
	SWZ Total	**18.36**	**18.22**	**17.94**	**17.87**	**17.73**
TOTAL	Tariff V (TJ/Day)	982	961	940	928	909
	Tariff D (TJ/Day)	227	224	220	221	222
	TOTAL (TJ/Day)	**1,208**	**1,185**	**1,160**	**1,148**	**1,130**

The following table summarises our annual demand (PJ) forecasts for each SWZ for APA's AA period.

Table 24: Annual demand forecasts – Total (PJ)

SWZ	Annual demand by SWZ (PJ)	2023	2024	2025	2026	2027
Ballarat	Tariff V	8.92	8.83	8.92	8.83	8.69
	Tariff D	1.60	1.59	1.59	1.59	1.59
	SWZ Total	**10.51**	**10.42**	**10.51**	**10.42**	**10.28**
Geelong	Tariff V	11.49	11.38	11.34	11.22	11.05
	Tariff D	8.88	8.76	8.54	8.55	8.56
	SWZ Total	**20.37**	**20.14**	**19.88**	**19.77**	**19.61**
Gippsland	Tariff V	5.85	5.89	5.82	5.76	5.67
	Tariff D	7.68	7.36	7.05	7.06	7.07
	SWZ Total	**13.53**	**13.25**	**12.87**	**12.82**	**12.74**
Melbourne	Tariff V	87.68	85.07	82.99	82.11	80.83
	Tariff D	32.54	32.05	31.38	31.43	31.48
	SWZ Total	**120.21**	**117.13**	**114.36**	**113.54**	**112.31**
Northern	Tariff V	1.29	1.28	1.26	1.25	1.23
	Tariff D	2.69	2.69	2.68	2.68	2.69
	SWZ Total	**3.98**	**3.96**	**3.94**	**3.93**	**3.92**
Western	Tariff V	11.19	11.09	11.05	10.94	10.77
	Tariff D	8.68	8.56	8.44	8.45	8.46
	SWZ Total	**19.87**	**19.65**	**19.49**	**19.39**	**19.23**
TOTAL	Tariff V	126.41	123.54	121.38	120.10	118.23
	Tariff D	62.06	61.01	59.67	59.77	59.85
	TOTAL (PJ)	**188.48**	**184.55**	**181.05**	**179.87**	**178.08**