GAS MARKET PARAMETERS REVIEW 2022

Final Recommendations Report

1 FEBRUARY 2023

NOTICES

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EXECUTIVE SUMMARY

Introduction

The Australian Energy Market Operator (AEMO) has engaged Market Reform to conduct the 2022 review of a number of parameters used in the Short Term Trading Market (STTM) and in the Victorian Declared Wholesale Gas Market (DWGM).

STTM market parameters are currently required to be reviewed at least once every five years in accordance with Rule 492 of the National Gas Rules (NGR). No similar requirement exists for a review of the parameters used in the DWGM. AEMO is using the occasion of an STTM review to undertake a third-party review the DWGM parameters also.

This report presents Market Reform's final findings and recommendations. The methodology proposed in this report is closely based on that used by Market Reform for the 2018 Review though the scenarios and data are revised. Some minor modifications were made to the methodology in response to are consultation on the draft methodology report for this review.

The study period

The gas market parameters under review are intended to be applicable from 1 July 2025. AEMO may seek to implement parameter changes earlier than this as allowed by NGR492(3).

Subsequent to the award of this work, Market Reform and AEMO have agreed to also review parameters for the year starting 1 July 2023. This is analysis is not part of the formal review but has been added to provide information of what the implications of different parameters are for 2023, which is expected to be a particularly tight supply year.

The range of years studied in this review was 1 July 2023 to 30 June 2028. This recognises that each gas market parameter review is triggered by a review of NEM parameters, and then next NEM review will apply from 1 July 2028.

Recommended Gas Market Parameters

We recommend no changes to the gas market parameters. The reasons for this are:

- The current parameters are still acceptable while still being close to the limits of what is acceptable.
- In the DWGM there are no options for adjusting CPT that both support investment and participant risk management. There is scope for increasing VoLL to $1000/GJ but it is no clear benefit to doing so.
- In the STTM, the analysis revealed no suitable alternatives for either MPC or CPT.
- We favour no change to the current APC values in both the STTM and DWGM. The AEMC's new settings of the NEM APC were based on the current gas APC values and raising the gas APC values would conflict with the NEM settings, potentially recreating some of the detrimental issues encountered in Winter 2022. While our analysis indicates lower APC values could be supported we do not propose it as it would significantly reduce market efficiency
- Preserving the current parameters minimises the impacts on current contractual arrangements.

Additional recommendations

The following recommendations may be viewed as beyond our scope but based on feedback and our own analysis and experience in conducting this review seem worthy of further consideration.

- There have been suggestions of aligning parameters between the DWGM and STTM. The goal of this would be to reduce the risk of one market being in an administered state earlier than another, creating distortions in flow between them. No single set of all three parameters was found that could be applied across both the DWGM and STTM. This result reflects the quite different market designs, including different frequencies and timeframes of scheduling. We instead recommend consideration of a new administered state trigger mechanism that would allow simultaneous administering or two or more markets from the DWGM and the three STTM supply and demand hubs. This should be in addition to the existing trigger mechanisms, and should be applied to mitigate detrimental impacts on inter-market gas flows when some markets are administered while others are not. The specific markets impacted would need to be determined as part of the event. The trigger would have to be a measure that reflects reduced supply to those markets where a rational response to the issue requires consistency of administered pricing between them.
- It would be beneficial to align the reviews of NEM paraments and the Gas Market Parameters. At minimum the reviews should be run concurrently with interactions between them. This would largely mitigate the risk of misalignment between parameters.

Market situation

In forming these recommendations, we have endeavoured to account for the future supply and demand positions of the relevant gas markets.

The DWGM and Adelaide and Sydney STTM hubs collectively face risks of small and infrequent shortfalls in winter from 2023 to 2026 under 1-in-20 year peak demand scenarios, though a potential shift away from gas to electricity could mitigate these risks. Later in the decade supply gaps may occur if anticipated gas infrastructure developments do not occur or are delivered late. The situation in these markets increases the impact of interactions with the National Electricity Market with high electricity market prices driving increased gas demand by Gas Powered Generation. Further, a general reversal of gas flows towards the DWGM as Victorian gas production declines will create further dependencies between Adelaide and Sydney STTM hubs and the DWGM. The Brisbane STTM is less impacted by these events, though some forecasts indicate small risk of tight supply in 2023.

The approach

Normal market price caps can have an impact on the efficiency of market outcomes. If the market clears where the supply and demand curves cross then market efficiency is maximised. Extreme prices that are not capped can translate into lost profits for gas buyers. Given an expectation of the profit lost during periods where price caps limit prices, we can translate this into a number of days of lost profit. We follow the convention of all prior reviews by defining an Acceptable Participant Risk to be no more than 500 days lost profit (based on a 50% hedged participant).

We used simulation of scenarios to assess the level of participant risk. We simulated outcomes for the DWGM and STTM across a time horizon during which an event is triggered that produces market stress. For a given scenario and market, each simulation was run without any price caps, to identify the maximum market efficiency solution, and with a trial set of gas market parameters (including current values) which, if binding, allows quantification of the reduction in market efficiency, i.e. the level of welfare loss.

For each case with the trial gas market parameters applied we recorded the level of participant risk for different representative participant classes, each with different business structures and characteristics.

The underlying assumption of this analysis is that the market is in equilibrium, such that supply and demand is aligned with the prevailing typical level of gas prices. For this reason our analysis used GSOO supply and demand data and corresponding price forecasts. These price forecasts are less than current levels of gas price.

Current levels of gas price are primarily driven by the Ukraine war. This may be resolved in six months. Equally, there could other be other events in the future, such as an economic downturn, that reduce gas prices. The best read on a potential future equilibrium is probably recent history prior to covid, and the GSOO price forecasts seem broadly consistent with that.

Put simply, determining Gas Market Parameters over the long term based on prices that may reflect transient effects can be very problematic. The market is not in equilibrium during transient events meaning that participants may be inadequately contracted and gas supply and demand will differ from GSOO forecasts.

Consultation

An industry consultation was conducted in regard to our draft recommendations. The feedback and our responses are provided in Section 8. No change in our recommendations were made in response to the consultation.

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TABLES

FIGURES

ABBREVIATIONS

ABBREVIATION	TERM
ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
ADGSM	Australian Domestic Gas Security Mechanism
ADL	The Adelaide STTM hub
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMDQ	Authorised Maximum Daily Quantity (DWGM)
APC	Administered Price Cap
BRIS	The Brisbane STTM hub
CPT	Cumulative Price Threshold
DTS	Declared Transmission System (DWGM)
DWGM	Victorian Declared Wholesale Gas Market
GJ	Gigajoule
GPG	Gas Powered Generation
GSG	Gas Supply Guarantee
GSH	Gas Supply Hub
GSOO	Gas Statement of Opportunities
GWCF	Gas Wholesale Consultative Forum
LNG	Liquefied Natural Gas
MCP	Marginal Clearing Price used in the DWGM CPT methodology. This is distinct from the market clearing price.
mmBtu	Million British thermal units.
MOS	Market Operator Service (STTM)
MPC	Market Price Cap (STTM)
MSV	Market Schedule Variations (STTM)
NBB	National Gas Bulletin Board

ABBREVIATION	TERM
NEM	National Electricity Market
NER	National Electricity Rules
NGERAC	National Gas Emergency Response Advisory Committee
NGR	National Gas Rules
PJ	Petajoule (1,000,000 GJ)
PUCT	Public Utilities Commission of Texas
RoLR	Retailer of Last Resort
STTM	Short Term Trading Market
SYD	The Sydney STTM hub.
TJ	Terajoule (1,000 GJ)
VGPR	Victorian Gas Planning Report Update 2022
VoLL	Value of Lost Load (DWGM)

1 INTRODUCTION

1.1 Background

The Australian Energy Market Operator (AEMO) has engaged Market Reform to conduct the 2022 review of a number of parameters used in the Short Term Trading Market (STTM) and in the Victorian Declared Wholesale Gas Market (DWGM) to ensure that they continue to be fit for purpose. The market parameters to be reviewed are collectively referred to as the gas market parameters and are described in Table 1.

Table 1 – The current gas market parameters

STTTM			
PARAMETER	PURPOSE	DOCUMENTED IN	VALUE
Market Price Cap (MPC)	The maximum market price to apply for a gas day.	National Gas Rules	$400/GJ
Administered Price Cap (APC)	A cap that replaces MPC during an administered price cap state so as to mitigate the risk of high prices.	National Gas Rules	$40/GJ
Cumulative Price Threshold (CPT)	The threshold for automatic imposition of an administered price cap state.	National Gas Rules	$440 (110% of MPC)
DWGM			
PARAMETER	PURPOSE	DOCUMENTED IN	VALUE
Value of Lost Load (VoLL)	The maximum market price.	National Gas Rules	$800/GJ
Administered Price Cap	A cap that replaces VoLL during an administered price cap state so as to mitigate the risk of high prices.	Wholesale Market Administered Pricing Procedures (Victoria)	$40/GJ
Cumulative Price Threshold	The threshold for automatic imposition of an administered price cap state.	Wholesale Market Administered Pricing Procedures (Victoria)	$1,400

STTM market parameters are currently required to be reviewed in accordance with Rule 492 of the National Gas Rules (NGR). This requires completion of the review no later than 6 months after the completion of each reliability standard and settings review under clause 3.9.3A of the NER (with this published on 1 September 2022). No similar requirement exists for a review of the parameters used in the DWGM. AEMO is using the occasion of an STTM review to undertake a third-party review of the DWGM parameters.

The cumulative price threshold is only one of a number of mechanisms for triggering administered states in each of the DWGM and STTM. These other triggers are beyond the scope of this work. When other triggers apply, e.g. a significant supply interruption or a Retailer of Last Resort (RoLR) event defined under the NGR, APC would still be applied.

This report presents the results of the review and Market Reform's recommendations. The methodology has been subject to industry consultation and the final methodology used was refined in response to participant submissions. The methodology used in this report is similar to that used by Market Reform for the 2018 Gas Market Parameter Review.

1.2 Advice sought

AEMO is seeking advice on the appropriate settings of the gas market parameters.

In developing recommendations, AEMO has asked for the review to have regard to the following:

1. Recognise links between markets

The analysis of the gas market parameters must recognise interactions between the STTM, DWGM and NEM, gas contracts and international gas markets, recent developments in each of these markets and the convergence of the gas and electricity markets. In particular, consideration of interactions between the STTM and DWGM and between each of these markets and the NEM should recognise the activities and operations of participants across markets.

2. Recognise industry structure and future developments

Any modelling of market outcomes should represent the broad industry structure as it exists today and include foreseeable changes to industry and market design in the future. Any changes to industry structure and market design since the previous review should be taken into consideration. Modelling need not attempt to represent actual industry players; it should represent the different distributions of participant size and roles in the contract and spot markets.

3. Data to be used

The determination of the gas market parameters should be based on available public and market data or be reasonable and logically based estimates of data values which are not otherwise public or available. Where historic or market data does not exist, Market Reform will have to adequately justify the use of alternative information.

4. Determination of MPC / VoLL

Market Price Cap (MPC) or Value of Lost Load (VoLL) is to be determined with the primary focus on economic price signalling as a market clearing incentive. It is to be a value greater than the maximum short run price expected to arise in the market, recognising that the STTM prices both the gas commodity and the cost of transmission in its prices whereas DWGM prices only include gas commodity costs. The value of MPC/VoLL is to be set with the aim of maximising the opportunity for an efficient market to clear in the short run. This objective implies that longer term investment costs will be recovered over time but does not restrict short run prices to be constrained by long run average cost.

In the STTM the value of MPC should be common to all hubs and across the ex-ante market price, contingency gas price and the ex-post market price. In the DWGM the value of VoLL should be common to all schedules.

In considering the short run cost of demand side response in each market, the appropriate measure should be the greater of the cost incurred for a rare temporary supply interruption and the cost of responding to a long-term loss of reliability due to supply side under-investment.

Whilst the setting of MPC/VoLL has fundamental implications for overall risk in the market and is a primary driver of that risk, the determination of its value is to focus on achieving economic price signals rather than to limit risk. Risk is addressed by the application of an administered price cap, and accordingly must be addressed when determining that price cap.

Market Reform is required to determine the appropriate settings of MPC and VoLL.

5. Determination of APC and CPT parameters

The purpose of the Administered Price Cap (APC) is as a last resort to address unmanageable risk in the market by limiting the impact of extreme and prolonged events. Accordingly, the APC is a balance between providing limitation of overall risk whilst maintaining appropriate incentives on individuals for prudent risk management and minimising distortion of incentives for appropriate investment.

APC is triggered by the Cumulative Price Threshold (CPT) or triggered as a result of events that occur on a given day, primarily force majeure type conditions.

The intent of CPT is a means of addressing unmanageable risk and distortions arising from prolonged exposure to very high prices. CPT allows for a high MPC/VoLL that meets the objectives of ensuring voluntary market clearing and at the same time allows management of risk due to high price.

Market Reform is required to determine the appropriate settings of APC and CPT.

1.3 The study period

The gas market parameters under review are intended to be applicable from 1 July 2025. AEMO may seek to implement changes earlier, applying from 1 July 2024 if this review identifies benefits in doing that.

Subsequent to the award of this work, Market Reform and AEMO have agreed to also review parameters for the year starting 1 July 2023. This is analysis is not part of the formal review but has been added to provide information of what the implications of different parameters are for 2023, which is expected to be a particularly tight supply year.

To cover all eventualities, in this report the study period means the period from 1 July 2023 to 30 June 2028. This recognises that each gas market parameter review is triggered by a review of NEM parameters, and then next NEM review will apply from 1 July 2028.

1.4 Report outline

This report is structured as follows:

- Section 2 provides an overview of the markets relevant to this review, the trends in those markets, and the drivers of risks in those markets.
- Section 3 describes the role and relationships between the gas market parameters and also describes bounds on acceptable values.
- Section 4 provides a description of the parameter assessment problem to be solved in this review.

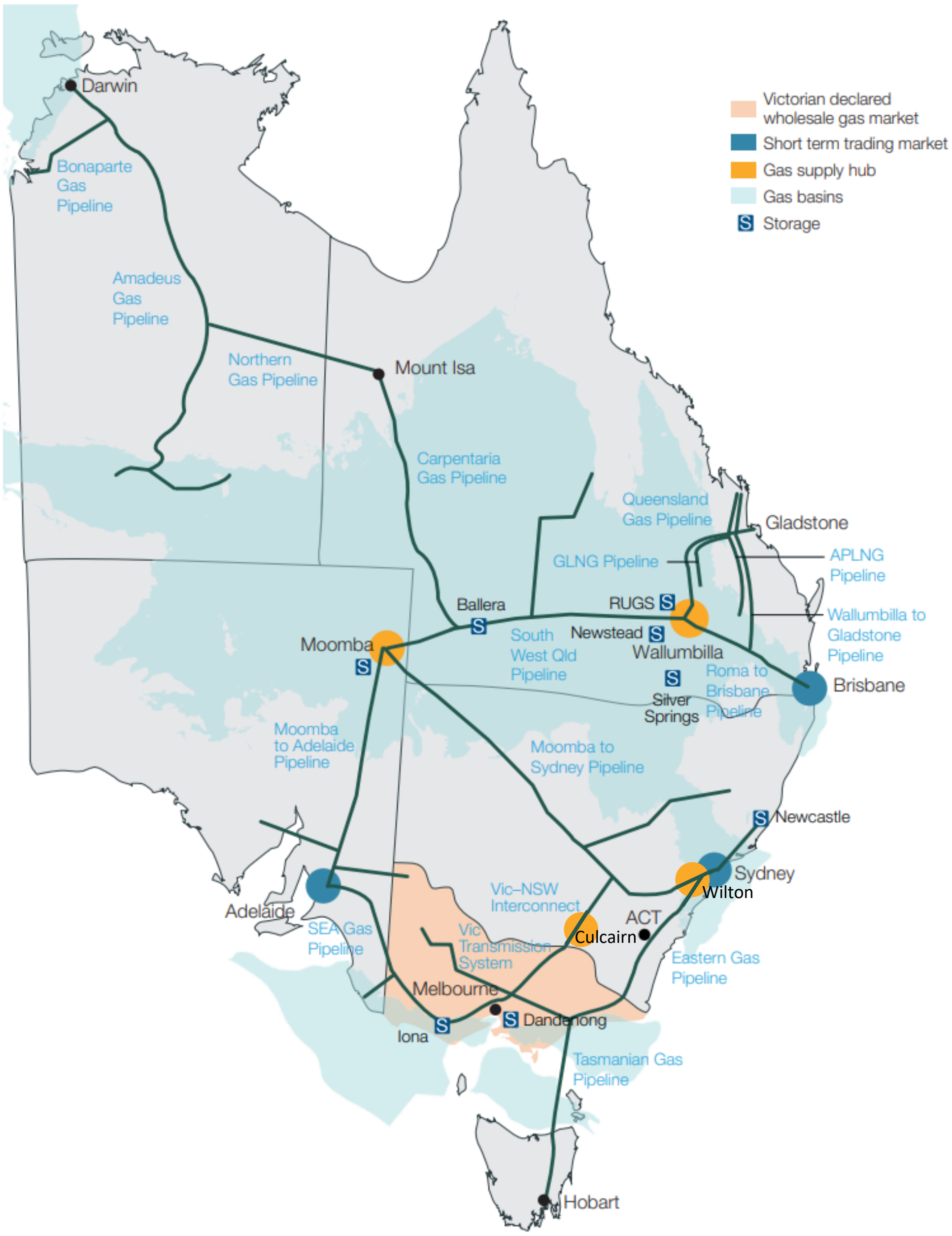
- Section 5 describes the solution methodology to the problem posed in Section 4. While this section refers generally to the scenarios to be considered, more detail of the actual scenarios under consideration is provided in Appendix A.
- Section 6 describes the key data and sources that were used in the modelling.
- Section 7 presents the study findings.
- Section 8 reports on the consultation on our draft recommendations.
- Section 9 presents our recommendations.
- Appendix A describes the scenarios considered.
- Appendix B provides summary data on the market outcomes in each scenario.
- Appendix C presents summaries of risk exposure levels for the different hypothetical participants.

2 OVERVIEW OF THE MARKETS AND DRIVERS OF RISK

2.1 The markets in the scope of this review

Figure 1 shows the location of the four markets in the scope of this review. The Victorian DWGM operates within the state of Victoria (light orange shaded area) while the three STTM supply and demand hubs at Adelaide, Sydney and Brisbane are indicated by the blue dots. While Figure 1 also shows the Gas Supply Hubs at Moomba, Wallumbilla, Wilton and Culcairn, these are outside the scope of this review.

Figure 1 – The Victorian DWGM, the STTM Hubs and the Gas Supply Hubs[1]



[1] Diagram from State of the Energy Market 2021 – Australian Energy Regulator 2nd July 2021. The Winton and Culcairn Gas Supply Hubs have been added to the version presented here.

It is important to appreciate that no form of administered price capping applies outside the DWGM and three STTM supply and demand hubs. This can make it attractive to sell gas out of these regions when administered price caps apply.

2.2 The context of the east coast during the study period

The 2022 Gas Statement of Opportunities (GSOO) [2] forecasts the adequacy of gas supplies out to 2041 in Australian jurisdictions other than Western Australia and the Northern Territory.

The GSOO considers a number of possible scenarios, and of particular relevance to this document is the outlook in the following scenarios:

- The *Step Change* scenario involves a rapid transition towards net-zero emissions, and high electrification (shifting from gas to electricity e.g., for residential heating) with relatively high renewable energy uptake. Notably stakeholder consultation on AEMO's 2022 Integrated System Plan identified this as the most likely scenario. Gas prices at the Wallumbilla Hub are forecast to decline continuously from $8.99/GJ in 2023 to $7.39/GJ in 2029.

- The *Progressive Change* scenario involves a more moderate trajectory towards net-zero, as well as moderate switching from gas to electricity, and therefore features higher gas demand compared with the Step Change scenario. Gas prices at the Wallumbilla Hub are forecast to decline continuously from $9.36/GJ in 2023 to $8.06/GJ in 2029.

The GSOO identifies risks of shortfalls in Victoria, Tasmania, New South Wales and the Australian Capital Territory due to gas flows being limited by existing pipeline capacity. Below are shown the GSOO's projected supply adequacy for the Step Change (Figure 2) and Progressive Change (Figure 3) for the south-eastern states. While these graphs show data out to 2041 this review does not extend beyond mid-2030.

[2] Gas Statement of Opportunities for Eastern and South-Eastern Australia, AEMO, March 2022.

Figure 2 – Projected annual adequacy in south-eastern regions in the GSOO step change scenario[3]

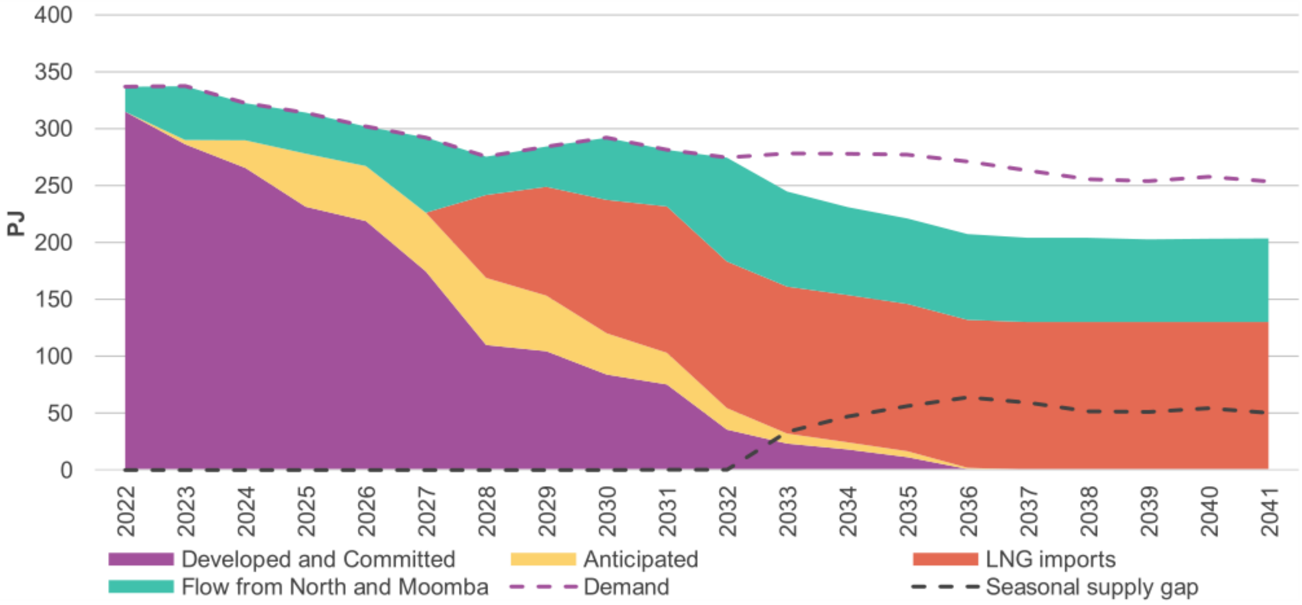
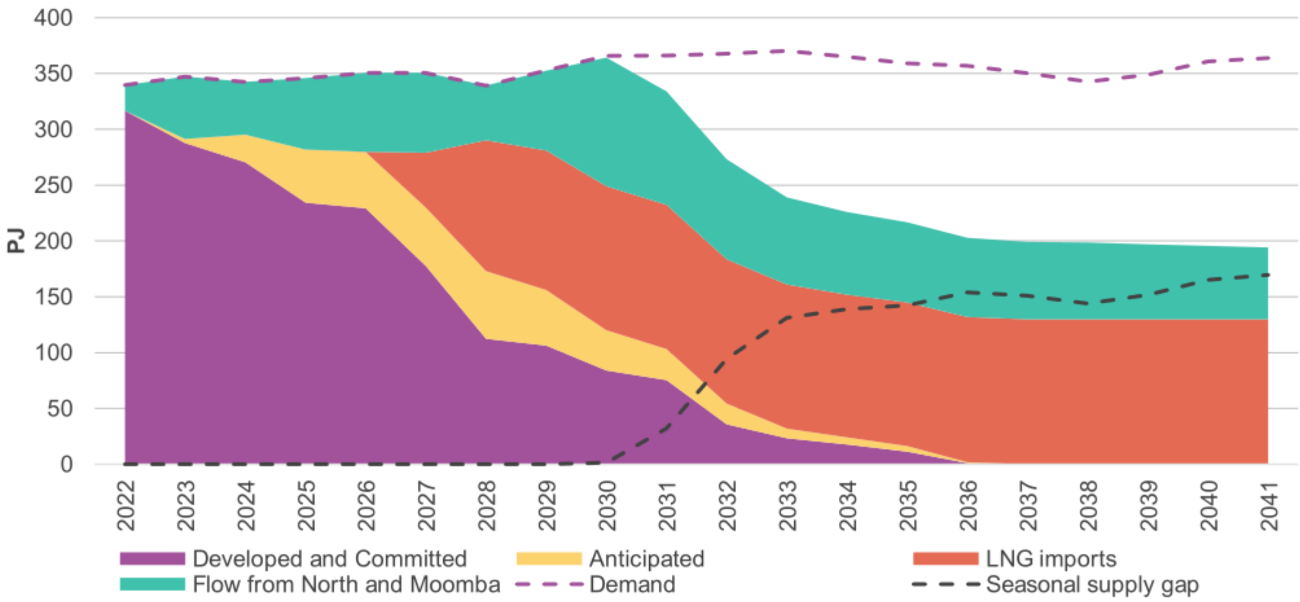


Figure 3 – Projected annual adequacy in south-eastern regions in the GSOO progressive change scenario[4]



The 2022 GSOO highlights the following trends and implications:

- South-eastern gas production is forecast to decline and remain at lower levels, making management of gas storage levels, whether as LNG or natural gas, increasingly important.

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[3] Reproduced from Figure 39 of the GSOO.
[4] Reproduced from Figure 40 of the GSOO.

- Requirements for gas-powered generation (GPG) as a source of flexible and firm electricity is a driver of gas demand and also of potential shortages on peak days. Curtailment of GPG output could avoid these shortfalls in the gas market but has the risk of moving the problem to the electricity market.
- Pipeline capacity limits on the Moomba-Sydney Pipeline (MSP) can constrain the transport of gas from northern producers to the south-eastern regions, even with expected completion of a Stage 1 upgrade by winter 2023. There are also limitations on transport of gas on the South West Pipeline (SWP) from Port Campbell (which connects at Iona) on peak demand days.

The GSOO forecasts risks of small and infrequent shortfalls in winter from 2023 to 2026 under 1-in-20 year demand for the Progressive Change scenario – however this is forecast to be (narrowly) avoided if greater electrification occurs as in the Step Change scenario.

Further into the 2020s, in the Step Change scenario supply gaps of up to 25-33 PJ are forecast to occur from 2028, if anticipated gas infrastructure developments do not occur (i.e., only considering developed and committed developments).[5] With higher gas demand in the Progressive Change scenario, up to 10 PJ supply gaps are forecast from 2026 with only developed and committed developments being completed.

Supply side mitigation of these risks is limited in the near-term (e.g., 2023) but could occur through delivery of the anticipated, but not confirmed, projects such as the Port Kembla Energy Terminal (from 2024), located south of Sydney. In addition, government measures that are in place which could mitigate gas shortage risks include:

- The Competition and Consumer (Gas Market Emergency Price) Order 2022 which came into effect on 23rd December 2022.[6] The order applies a temporary price cap of $12/GJ[7] on new contract sales of gas for Australian jurisdictions other than Western Australia. The price cap applies to gas being sold by producers to commercial and industrial users, and is to apply for 12 months. This order does not materially impact this work as:
  - The order contains a number of exceptions, one of which that it does not constrain the price of gas being sold through the STTMs and the DWGM. The price cap also does not apply to gas contracts that were entered into prior to 23rd December 2022 (unless a variation is entered into during the price cap period), or for sales of gas that are intended for international export.
  - The Order is only in place until December 2023, so would only apply to 6 months of the period studied.
- The Australian Domestic Gas Security Mechanism (ADGSM) whereby the Federal Minister for Resources may, after a consultation process, impose LNG export restrictions for years in which a domestic gas shortfall is forecast. The scheme has been extended until 1st January 2030.
  - In 2021 a Heads of Agreement was established between the Federal Government and LNG exporters to make uncontracted gas available first to the domestic market before offering it to the international market.

[5] The GSOO identifies Port Kembla Energy Terminal near Sydney, Golden Beach near Longford, and some additional Victorian offshore developments as being anticipated projects that would help alleviate possible supply gaps.
[6] See Explanatory Statement - https://www.legislation.gov.au/Details/F2022L01743/Explanatory%20Statement/Text
[7] The Explanatory Statement states "The maximum price of $12 per GJ has been assessed to be a price which covers costs of production plus a reasonable rate of return on capital for gas sourced from developed fields."

- In August 2022 the ACCC reported failings and shortfalls in these arrangements in practice.[8]
- In September 2022, the Federal Government announced that a new Heads of Agreement had been agreed with three LNG exporters. This is expected to see an additional 157 PJ of gas offered into the domestic gas market for 2023.[9] As a result the ADGSM is not expected to be activated in 2023. The agreement includes the principle that domestic gas consumers will not pay more for the gas than international gas buyers, and makes reference to the ACCC's LNG net back price.[10]

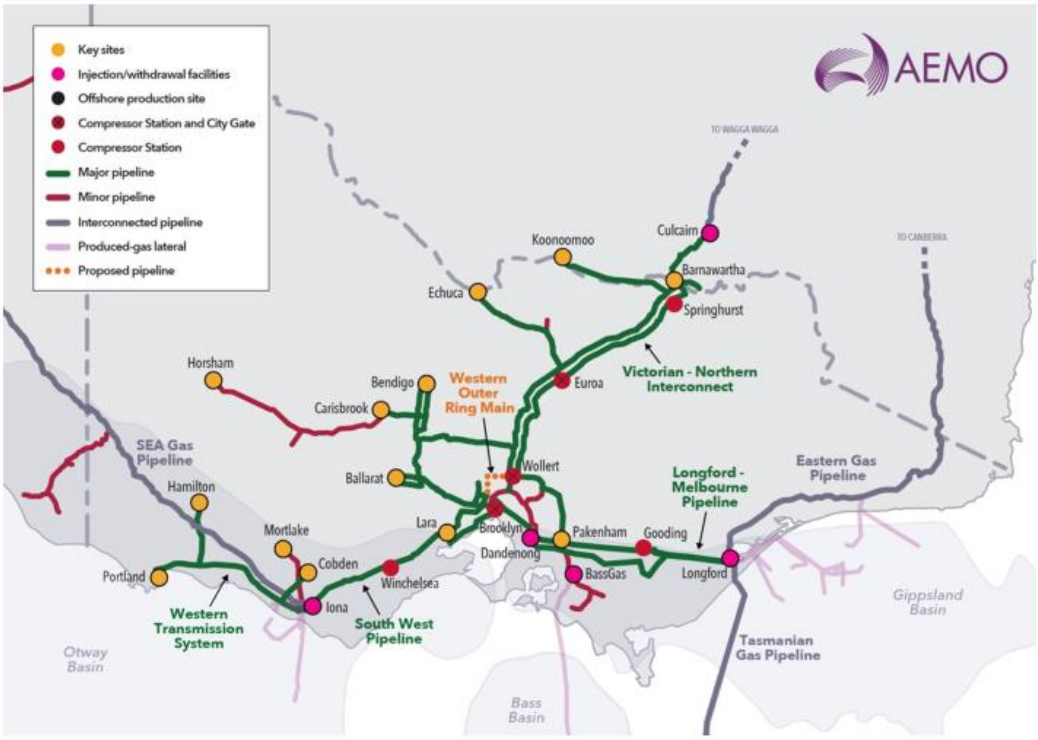
- The Gas Supply Guarantee (GSG) is a separate mechanism developed between the Commonwealth Government and gas producers and pipeline operators to make gas supply available to electricity generators during peak NEM periods. The AEMC has recommended that it be extended to March 2026.

2.3 Victorian Declared Wholesale Gas Market

2.3.1 Current industry structure

The DWGM is a market that operates across the Declared Transmission System (DTS) in Victoria. The extent of the DWGM is represented by the green pipelines in Figure 4.[11] This market is connected with New South Wales, South Australia and Tasmania via transmission pipelines that are not part of the market.

Figure 4 – The Victorian Declared Transmission System[12]



[8] ACCC – LNG exporters must divert gas to the domestic market to avoid shortfalls, media release, 1 August 2022.
[9] https://www.minister.industry.gov.au/ministers/king/media-releases/australian-government-secures-gas-supply
[10] https://www.industry.gov.au/sites/default/files/2022-09/heads_of_agreement_the_australian_east_coast_domestic_gas_supply_commitment.pdf
[11] The red pipelines include distribution networks.
[12] Reproduced from Figure 9 of the VGPR.

The main gas supply points are from Iona, BassGas, and Longford. Pipelines at Longford connect to Tasmania and NSW/ACT while Iona is connected with SA. Flows from or to NSW can also flow via Culcairn. An underground gas storage facility is located near Iona while an LNG storage facility is located at Dandenong.

Consumers in Victoria are primarily supplied by retailers but large customers can purchase gas directly from the market. Participants use contracts to limit their market exposure. Unlike other states, most demand is residential followed by industrial consumption. Due to the significant degree of heating load, demand is highly seasonal. Average summer demand is around 300 TJ/day but winter demand can be in the region of 1,200 TJ/day.

Since the launch of Queensland's LNG export projects in 2015, a cycle has developed, in which gas flows south from Queensland toward the southern States (NSW, VIC, SA, TAS) in winter to meet heating demand, and north from the southern States to Queensland in summer to supply LNG export facilities with gas for Asian winter demand peaks. In general, pipelines to other states can act as supply or demand in the DWGM.[13]

2.3.2 Supply and demand trends

There are a number of possible significant supply and demand changes going forward. These changes are factored into the broader east coast gas situation but are important to the DWGM context. The most recent Victorian Gas Planning Report Update (VGPR)[14], which only forecasts to 2026, identifies the following:

- Future gas needs are uncertain, with significant variation across plausible scenarios. For example, in the Progressive Change scenario, Victorian annual consumption and peak day demand remain relatively flat to 2026 (from 2022 forecast levels), while they decrease by 17% and 18% respectively in the Step Change scenario. However, both the Progressive and Step Change scenarios identify growth in large commercial and industrial gas demand, due to uptake in steam methane reforming.
- This demand-side uncertainty is being reflected in a relative hesitancy of the market to contract for future supply. In particular, in previous versions of the GSOO the Port Kembla Energy Terminal was classified as a committed project available from 2023, but in the 2022 GSOO, is now anticipated (i.e., not considered to have passed a final investment decision) for completion by 2024, due to uncertainty that sufficient capacity will be contracted to justify the project.
- Victorian gas production is forecast to continue to decline, with existing and committed supply forecast to decline from 360 PJ (2022) to 243 PJ (2026).
- The supply demand balance is tight in the Progressive Change scenario in particular, with a supply deficit being forecast for 2026, even under a 1-in-2-year demand event, as described further below.
- However, there are several anticipated projects which are forecast to become available (though have not reached a final investment decision) which would then help to provide additional supply.[15]

The 2022 VGPR Update does not forecast any material peak day shortages until 2026, though the supply-demand balance is tight from 2023, and may require curtailment of gas generation and use of LNG from the Dandenong

[13] See Table 19 of the Victorian Gas Planning Report Update 2022 (VGPR).
[14] VGPR.
[15] For example, Golden Beach in the Gippsland Basin near Longford (forecast supply of 43 PJ from 2024) and other projects as described in the VGPR.

storage facility on high demand days. The 1-in 20-year peak demand forecast for the DWGM in 2023 is 1248 TJ/day (Progressive Change). The forecast daily supply availability is 1287 TJ/day comprised of:

- 666 TJ/day from Gippsland,
- 476 TJ/day from Port Campbell near Iona (including under-ground gas storage),
- 87 TJ/day of LNG from Dandenong in Melbourne, and
- 59 TJ /day from NSW,

Resulting in a surplus of 39 TJ/day.

By 2026, deficits of 130 TJ/day and 23 TJ/day are forecast against 1-in-20 and 1-in-2-year demand, respectively.

2.3.3 System operation

AEMO is the system operator for the Victorian Declared Transmission System (DTS). The primary operational consideration is managing pressure, and hence linepack (gas stored in pipelines), within day and between days. It can take in the region of nine hours for gas to flow from Longford to Melbourne but demand in Melbourne can rise rapidly if temperature drops. Gas production facilities tend to supply gas at a constant rate, with that rate only changing at a few discrete intervals during the day.

AEMO must manage the linepack distribution across the system, through scheduling gas and operating compressors to maintain gas flows within the day. Between days, AEMO must manage end-of-day linepack to ensure that the system pressures at the end of the day are compatible with achieving required gas flows to satisfy forecast demand on the next gas day.

The normal operational process is to schedule gas through the market to meet demand across the gas day. As demand changes, rescheduling of gas injections can increase supply as required but, once it becomes too late to deliver gas from distant (low cost) locations, AEMO must schedule higher cost LNG from Melbourne to serve demand locally.

2.3.4 Market design

AEMO is the market operator of the Victorian DWGM. The DWGM is designed to facilitate the efficient scheduling of gas. Most market participants are retailers or direct market customers who also hold contracts for gas supply from gas producers, storage fields or other supply sources. The DWGM operates under a "market carriage" arrangement meaning that market participants have access to the DTS and are entitled to flow the gas that they have scheduled. The DTS is funded by Transmission Use of System Charges so the cost of the accessing the network is not included in the gas market.

To schedule gas, market participants place bids to inject gas at injection points to the DTS or place bids to buy gas at controllable withdrawal points from the DTS, and forecast their uncontrollable demand that will be taken at any price. AEMO can modify the aggregate demand forecast and profiles that across the network. Gas powered generation (GPG) is treated as uncontrollable demand forecast.

AEMO determines a constrained operational schedule which endeavours to efficiently match supply with demand while accounting for operational and network constraints in the DTS. Separately AEMO solves an "infinite tank" version of the gas scheduling problem that ignores transmission constraints and defines an unconstrained pricing schedule that sets market prices. To the extent that operational constraints result in a different actual pattern of injections or off-takes, then those who are constrained on are compensated by an ancillary payment, with this funded through an uplift charge applied to those deemed to have caused it (if identifiable) or through an uplift on all consumption (if not identifiable). Authorised Maximum Daily Quantity (AMDQ) is a form of hedge available in the market that provides some protection against uplift charges for the holders. From 1 January 2023, AMDQ is replaced by Capacity Certificates which will only provide tie breaking rights (see Section 2.3.5).

The market is scheduled five times per day, based on bids and demand forecasts closing 1 hour before the schedule. It runs by 6 AM for the following 24 hours, by 10 AM for the following 20 hours, by 2 PM for the following 16 hours, by 6 PM for the following 12 hours, and by 10 PM for the following 8 hours. The 6 AM schedule is the primary market schedule with all gas scheduled settled at the single market price applicable to that schedule (with constrained on ancillary payments funded separately). At each subsequent schedule, changes from the prior schedule are settled at the new market price. Actual deviations in gas flow during a scheduling interval from that scheduled are settled based on the price in the next scheduling horizon. Thus, if a participant over supplies at 9 AM then this will be priced at the price determined in the 10 AM schedule. The total uplift for the day required to fund constrained on ancillary payments is determined at the end of the day after the net ancillary payments take any successive positive and negative ancillary payments into account.

Most uplift in the market today is related to surprise events, though in the past there have been periods where congestion has dominated uplift (e.g., in 2007 just prior to an expansion of the gas network's storage capabilities). However, from 1st January 2023, congestion uplift will no longer apply (see Section 2.3.5).

2.3.5 Upcoming market design changes

The August 12th Energy Ministers meeting confirmed that an urgent rule change has been submitted to the AEMC to give AEMO power to contract underutilised storage capacity at Dandenong before winter 2023.[16]

Also of note are two determinations made by the AEMC that will update the DWGM design applicable to the study period:

- Effective from 1st January 2023 the AEMC's *DWGM Improvement To AMDQ Regime* rule change[17] replaces the current authorised maximum daily quantity (AMDQ) regime with a new approach that uses entry and exit capacity certificates.
- The AEMC's *DWGM Simpler Wholesale Price* rule change[18] requires pricing schedules to account for transmission constraints that affect withdrawals of gas, and removes the congestion uplift category. The congestion uplift framework is effective from 1st January 2023 (aligned with the AMDQ regime change), while the new arrangements for transmission constraints commenced in 2020.

A related rule change request proposed the introduction of a voluntary forward trading market for the DWGM, but the AEMC determined not to make a rule in this respect.

We have not identified any need to specifically to account for these changes in the gas parameter review which focuses on market clearing prices.

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[16] https://www.energy.gov.au/sites/default/files/2022-08/Energy%20Ministers%20Meeting%20Communique%20-%2012%20August%202022.docx

[17] AEMC - National Gas Amendment (DWGM Improvement To AMDQ Regime) Rule 2020 Rule Determination, 12 March 2020.

[18] AEMC - National Gas Amendment (DWGM Simpler Wholesale Price) Rule 2020, 12 March 2020

In response to a rule change request by the Victorian Minister for Energy, Environment and Climate Action the AEMC has commenced a consultation[19] on proposed rule change to require the Australian Energy Market Operator (AEMO) to:

- act as buyer of last resort of capacity in the Dandenong liquified natural gas storage facility and hold a target level of LNG stock in this facility during the winter months
- act as supplier of last resort in relation to the use of its LNG stock.•

This rule change, if adopted as proposed, would have the effect that AEMO's LNG stock would only be available to the market at a price of VoLL. This rule change process is not expected to be completed in the time frame of this review. If it were to be factored into our study then it would imply a minimum level of LNG in each scenario to be priced at VoLL. However, as the scenarios are designed to create conditions that would trigger administered pricing it is not critical to include this feature.

In August 2022, Energy Ministers agreed to explore a range of actions to support a more secure, resilient and flexible east coast gas market.[20] These actions are split into two tranches:

- Tranche 1 contains urgent regulatory amendments that empower the Australian Energy Market Operator (AEMO) to better manage gas supply adequacy and reliability risks ahead of winter 2023, across four main initiatives:
  - Monitoring the gas system(s) through the increased collection and assessment of data.
  - Signalling to industry when a threat to reliability/supply adequacy has been identified, including convening conferences and mandating attendance.
  - Directing gas industry participants to resolve a threat (especially where the market has/is not able to resolve the threat).
  - Trading in gas itself where necessary system reliability or supply adequacy threats.
- Tranche 2 contains reforms that, in the longer term, progress development of further supply adequacy and reliability measures which will help to guide how AEMO delivers its new functions. Tranche 2 reforms under consideration include a gas reliability standard, a demand management framework and a Projected Assessment of System Adequacy process (as exists in the NEM), but these are much less developed than those in tranche 1.

The policy was still being developed and consulted on during the course of this work, and therefore was not considered in the parameter assessment. We do not consider directions in this study as the focus is on market schedules and price outcomes given available supply and demand of gas based on GSOO forecasts of future conditions. While we do not consider AEMO directly trading in gas, the policy highlights that this is intended to be used sparingly.

[19] AEMC - Consultation Paper: National Gas Amendment (DWGM Interim LNG Storage Measures) Rule 2022, 1 September 2022.

[20] Australian Government, Department of Climate Change, Energy, the Environment and Water - Extension of AEMO Functions And Powers to Manage Supply Adequacy In the East Coast Gas Market, Consultation paper September 2022.

2.3.6 Price caps and triggers

Current price cap settings are as follows:

- The current market price cap (termed VoLL) in the DWGM is $800/GJ.
- The current administered price cap is $40/GJ.
- The cumulative price threshold is $1,400/GJ.

Under the Administered Pricing Procedures, AEMO will impose the administered price cap if any one of the following applies:[21]

- The market is suspended.
- Material curtailment has been ordered.
- Minor or Major Retailer of Last Resort (RoLR) event.
- AEMO is unable to publish a market price or pricing schedule as a result of a software failure.
- The cumulative price threshold (CPT) is exceeded.

The cumulative price period is 35 consecutive scheduling intervals (and with five schedules per day this would be seven days if the first period were at a 6 AM schedule). The notional Marginal Clearing Price (MCP) used in forming the CPT is the greater of the ex-ante market clearing price from the unconstrained pricing schedule and the highest priced injection offer scheduled from the operational schedule. Thus, if for a schedule, the unconstrained market clearing price was $10/GJ but $20/GJ for LNG was constrained on in the operational schedule then the MCP (for the purpose of the CPT only) would be $20/GJ.[22] The imposition of the APC is not considered in the calculation of MCP.

If the sum of the MCP values for 35 successive schedules exceeds the CPT of $1,400/GJ,[23] then from the first schedule for which this occurs, the maximum price in the market will be decreased from the VoLL ($800/GJ) to the APC ($40/GJ) until the end of the gas day following the gas day for which:

- the cumulative price last fell below the CPT, and
- no other trigger for APC exists.

Note that two successive schedules (schedules 1 and 2) with prices at the VoLL (whether as a result of high market prices or the cost of constrained on gas) would result in a breach of the CPT until the 36th schedule (seven days later) and the application of the APC.[24] CPT would also be triggered if the market price were at the VoLL for one period followed by accumulated prices over 34 periods with an average value that exceeds approximately $17.14/GJ.

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[21] Wholesale Market Administered, Pricing Procedures (Victoria) v4, AEMO, 1 July 2020.
[22] In the modelling, constrained on injection bids was specified exogenously based on the nature of the scenario.
[23] It is purely coincidental that the current CPT of $1400 divided by 35 periods equals the APC value of $40/GJ.
[24] As would one interval at the VoLL, followed by 34 intervals with an average price exceeding approximately $18/GJ.

2.3.7 Drivers of unmanageable risk for participants in the DWGM

Given the design of the DWGM and nature of the DTS, some of the major short-run unmanageable risk factors[25] for participants in the DWGM which could lead to a high MCP – either through the market clearing price or a high-cost constrained-on resource - include:

- Production failure on a high-demand day.
- Pipeline compressor failure limiting ability to move gas.
- Very high demand (beyond expectations), e.g., due to:
  - Extremely cold weather
  - High rate of gas export to support other markets in stressed situation.
  - High GPG demand (e.g., surprise event during the day).
- Low reserves of stored gas (e.g., LNG to support Melbourne).
- VoLL triggered by bidding behaviour at a system withdrawal point (e.g., failure to schedule supply to hedge that position which drives price to VoLL).

Each of these events could take more than two scheduling intervals to resolve so could produce cumulative prices that could trigger APC. For each event, the extent of the event will determine whether the situation can be addressed by dispatchable resources. Once dispatchable resources are exhausted, the market will be in an emergency situation, for which APC is likely to apply anyway, independent of the CPT trigger. Accordingly, our focus is on eventualities that can be addressed by dispatchable resources.

There are also longer-term risks – such as the ability to secure contracted gas and the general supply and demand situation for gas (including in external or international markets) – that can vary the level of exposure created by events in the short-run. The ACCC's Gas Enquiry 2017-2025[26] has described upstream competition in the gas market as ineffective, due both to concentration of gas supply and structural issues.

Specific scenarios under consideration for inclusion in this review are provided in Appendix A.

2.4 Short Term Trading Market

2.4.1 Current industry structure

The STTM includes three supply and demand hubs – Adelaide, Brisbane and Sydney. Their locations in the broader gas system are shown in Figure 1 (blue circles) above. Note that the Wallumbilla and Moomba gas supply hubs operate under different rules and are outside the scope of this review.

Each of the three in hubs within this reviews scope is a notional trading point between a distribution network and the delivery points of one or more transmission pipelines. Adelaide and Sydney are served by two and three

[25] We use "unmanageable risk"" in the context of administered pricing existing to address unmanageable risks for participants. In this context we are referring to events beyond those that participants would reasonably be expected to hedge against.
[26] July 2022 (Updated 1 August).

transmission pipelines respectively, while Brisbane is only supplied by a single pipeline. Sydney also has one production facility and an LNG storage facility connected to the hub.

The demand within each hub is a mixture of residential, commercial, and industrial load. There are GPGs within the Brisbane and Sydney hubs and there is also consumption by GPGs on the transmission pipelines outside each hub, resulting in strong links to the electricity market.

In 2020, STTM volumes increased relative to previous years, with gas traded through the STTM meeting approximately 25%, 22% and 8% of demand in Sydney, Adelaide and Brisbane, respectively.[27]

2.4.2 Supply and demand trends

The GSOO does not provide STTM hub specific information, though the discussion of the supply and demand trends in Section 2.1 is broadly applicable to the STTM hubs. In particular, there is no current forecast of shortfall for Brisbane, while Adelaide and Sydney share in the potential overall shortfalls for south-eastern region.

Without the reduction in gas demand that occurs in the Step Change due to electrification, infrequent gas shortages are forecast from 2023, but these become more severe by 2026 with the reduction in south eastern production. The delivery of anticipated projects would alleviate all forecast supply gaps, except in 2023.

The ACCC's Gas Enquiry 2017-2025[28] indicates that Queensland could be in a tight situation in 2023. A small shortfall of 2 PJ is predicted in 2023 if LNG exporters decide to export all of their excess gas. The 2 PJ net demand increase comprises a 21 PJ increase in demand less a 16 PJ increase in supply. The increase in demand is primarily a result of a 17 PJ increase in AEMO's GPG forecasts and a 24 PJ increase in the amount of gas that LNG exporters expect to export under LNG SPAs and spot cargoes, with this increase partially offset by a 20 PJ contraction in demand, with AEMO projecting that the commercial and industrial customers in Queensland will account for around 75% of this contraction. According to the ACCC, and while not stated in the GSOO, the reduction appears to be related to the closure of Incitec Pivot's Gibson Island plant at the end of 2022, which was announced in November 2021.

2.4.3 System operation

The STTM hubs do not have a single system operator. Rather, each transmission pipeline operator is responsible for the operation of its pipeline while the distribution system operator manages its network.

Shippers source gas from contracts with producers (or buy from other markets such as the DWGM) and hold shipping contracts on the pipelines. These shipping contracts can be of different priority – e.g., firm or "as available". A shipper without firm access may not be able to schedule gas on a pipeline if firm shippers are using it. Shippers must nominate to the pipeline operator the quantity of gas they want to flow on the pipeline to the hub under their contracts. This is influenced by the market processes discussed below. Within the distribution network the end consumers take delivery of shipped gas. While the STTM design assumes no constraints in the distribution network these can occur, limiting the ability of a gas to get to a customer.

[27] State of the Energy Market 2021 – Australian Energy Regulator 2nd July 2021.
[28] July 2022 (Updated 1 August).

Demand outside the hub – such as for gas powered generators – has the option to purchase gas from the hub and "back haul" it along a pipeline. Alternatively, they could have gas shipped to them via forward haulage on the pipeline without participating in the hub.

2.4.4 Market design

AEMO operates the STTM. To a large degree it can be thought of as an exchange which allows parties to trade gas with the actual scheduling of gas occurring through pipeline operator processes.

A day-ahead market determines a single daily quantity of gas for each shipper or user of gas. Shipper offers must be associated with shipper contracts they have on an STTM facility[29] or they may also bid on a transmission pipeline backhaul contract. Shipper offers at each hub must cover the cost of these arrangements. Users place priced or price taker bids for gas on distribution networks.

The facility operators must specify the capacity that they can deliver to the hub each day. This is a dynamic number as it depends on the level of demand upstream of the hub, which may not be known with certainty at the time the capacity is specified.

AEMO runs the market for each hub independently. The results of this market are published by 12:30 PM on the afternoon prior to the day of delivery. The outcome of this market is a schedule for each shipper on each pipeline and for each user to take gas from the hub. These schedules apply for the 24 hours from 6 AM on the day of delivery. An ex-ante market price at the hub is determined, as well as a price on the capacity of each pipeline if the pipeline flows are at capacity.

Buyers and sellers of gas are settled at the ex-ante market price. The capacity price is not applied to ex-ante trades – rather it is applied ex-post to actual flows. Shippers with non-firm pipeline capacity pay the capacity price to firm shippers who did not flow gas.

The day-ahead schedules are used by shippers to nominate gas flows to pipeline operators under normal pipeline scheduling process under their contracts. But there is no guarantee that they will necessarily secure that schedule on the pipeline.

On the day gas flows shippers are able to re-nominate increases or decreases under their contracts, or may trade with other shippers at a bilaterally determined price that is not seen by the market. Participants must notify AEMO of the volumes and counter parties for these bilateral trades via Market Schedule Variations (MSVs) if they are to be reflected correctly in STTM settlements. A small variation charge is imposed by the market on MSVs so as to encourage such trades to occur in the more transparent day-ahead market.

A contingency gas process also exists to handle events which could undermine the supply and demand situation in an STTM hub after the market has run. In situations where there is a trigger event, AEMO conducts a contingency gas conference to determine if additional gas flows are needed to manage the trigger event. Industry participants have an opportunity to accommodate the event triggering the conference but if required, AEMO can determine the need for contingency gas and can schedule contingency gas flows from offers submitted on the previous day and confirmed as available on the day. Offers can either be from pipelines or from sources

[29] A shipper can bid on STTM facilities - pipeline, production facility and storage facility.

(including demand side resources) in the hub. If contingency gas is scheduled then this also adjusts the positions of participants but is settled by AEMO at a contingency gas price.

The final schedule position of each participant is a function of its ex-ante market position, any intraday re-nominations or trades (as reflected in MSVs) and any contingency gas schedules. In the event of a material involuntary curtailment of gas in a hub then those who consume less than scheduled will be settled at the ex-ante price, while those who consume more than scheduled will be settled at the Market Price Cap (or the Administered Price Cap if applicable).

The STTM design includes the concept of Market Operator Service (MOS). Where the quantity of gas delivered on a pipeline differs from the pipeline schedule, AEMO tells the pipeline operators how to allocate MOS gas based on MOS offers provided to AEMO by competing MOS providers. These MOS offers reflect the cost of providing the service, since the MOS providers must pay the pipeline operator to allow them to provide these services. AEMO recovers the cost of the MOS service from participants that deviate from schedule. The MOS providers also have to replace the gas that flowed on the pipeline from which they provide the service. AEMO pays or charges the MOS provider for the MOS gas allocation on the gas day at the ex-ante market price for the gas day two days after the MOS gas flowed, which covers the cost of the MOS provider of restoring its inventory of MOS gas. To procure replacement gas the MOS provider has the choice of trading it in the gas day two days after the MOS gas flowed (at no price risk but with quantity risk) or to run down its MOS gas allocation on the gas day.

Pipelines operate in a flow control (constant flow) or pressure control (variable flow) mode. Where constraints occur in the distribution network then multiple pipelines, or multiple delivery points on the same pipeline, must operate in pressure control mode to ensure supply matches demand in different parts of the distribution network. This can result in increased MOS and decrease MOS occurring simultaneously on different pipelines in a hub.

To the extent that different volumes of gas actually flow on the pipeline, then the pipeline operators allocate these to MOS providers.

After the day, AEMO determines an ex-post imbalance price which reflects what the price would have been given knowledge of actual deliveries to the hub.

Deviations from the scheduled volumes of gas which improve the supply and demand situation (increased supply or decreased demand) are settled at a low deviation price based on the lesser of the ex-post imbalance price, ex-ante price, MOS costs for decreased flows, and the contingency gas price.

Deviations from the scheduled volumes of gas which worsen the supply and demand situation (decreased supply or increased demand) are settled at high deviation price based on the greater of the ex-post imbalance price, ex-ante price, MOS costs for increased flows, and the contingency gas price.

To the extent that the market has any shortfall or surplus revenue over a billing period then surpluses are partly allocated back to those who funded deviations (subject to a $0.14 per GJ cap) while shortfalls and the balance of surpluses are recovered in proportion to withdrawals.

2.4.5 Upcoming market design changes

Other than new direction powers for AEMO under development, as discussed above in the context of the DWGM, we are not aware of any other measures or rule change proposals that would materially change the design of the STTM hubs such that they should be considered in this review.

2.4.6 Price caps and triggers

The following price caps and settings currently apply in the STTM:[30]

- The market price cap is $400/GJ.
- The administered price cap is $40/GJ.
- The cumulative price threshold is 110% of the market price cap, i.e., $440/GJ.
- The CPT horizon is seven gas days.

The price to be accumulated is complex, as each day an ex-ante price is determined for the next day, contingency gas prices may be determined for the current day, and deviation prices are determined for the prior day. Hence the new contribution to the cumulative price each day *d* is the sum of:

- The contribution of the (positive) ex-ante price determined on day *d* for day *d+1*.
- The further (positive) increase in cost beyond the ex-ante price for day *d* determined on day *d* due to contingency gas scheduled in day *d* (5.5. hours into the gas day when the calculation is done[31]).
- The further (positive) increase in cost beyond the (positive) ex-ante price for day *d-1* determined on day *d-2* and the (positive) increase in that due to contingency gas for day *d-1* determined on *d-1* due to the high deviation price (capped at the applicable market price cap) for day *d-1* determined on day *d*.

Each day, the cumulative price is formed by adding the term described above to the total and removing the corresponding term from 7 days prior from the total. Generally, the prices used in the calculation of the cumulative price are the raw prices without application of the APC.[32] AEMO makes its determination of whether the CPT has been exceeded for a gas day during the prior gas day. It follows that APC will cease on the day following the last gas day for which the CPT is exceeded.

For a period where no contingency gas occurs, the relevant price that gets accumulated is simply the ex-ante price for the following day (i.e., *d+1*) plus the amount by which the high deviation price (capped by MPC) for the previous day (*d-1*) exceeds the ex-ante market price for that day.

With similarity to the previous section on the DWGM, two scheduling intervals in which the accumulated price is at the MPC would be sufficient to exceed the CPT, as would one interval at the MPC, followed by accumulated prices over six days with an average price that exceeds approximately $6.67/GJ.

2.4.7 Drivers of unmanageable risk for participants in the STTM

Given the nature of the STTM design, some of the major short-run unmanageable risk factors for participants in the STTM include:

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[30] Administered pricing can also be triggered for operational reasons, including defined involuntary curtailment events and significant operational constraints that reduce supply.
[31] This is when the ex-ante price for the next day is determined.
[32] Exceptions apply if AEMO is unable to produce ex ante schedules or ex post prices in a timely manner, in which case the price used will be capped at APC.

- Production failure limits supply to the hub.
- Pipeline compressor failure limits the ability to move gas to the hub.
- High GPG demand outside the hub reducing capacity to deliver to the hub.
- Very high demand (including in the broader gas markets).
- Contingency gas scenarios resulting from the above risks.

Each of these events could take more than two scheduling intervals (days) to resolve. For each event, the extent of the event will determine whether the situation can be addressed by dispatchable resources. The multiple day nature of the STTM settlement processes also means that there may be linkages between gas days. For example, a MOS provider could be exposed to risks from the cost of replacing gas two days after a gas day.

As with the DWGM we focus these risks on situations which can be addressed by dispatchable resources without requiring involuntary curtailment (as such events will trigger APC anyway). Again, there are also longer-term risks that can vary the level of exposure created by events in the short-run. Also, as for the DWGM, the limitations of upstream competition effectiveness identified by the ACCC may impact contracted gas prices.

Specific scenarios under consideration for inclusion in this review are provided in Appendix A.

2.5 Market linkages

2.5.1 Linkages between DWGM, STTM and broader gas markets

The Adelaide and Sydney STTM hubs are connected via transmission pipelines to the DWGM and gas can be moved between these markets. Key considerations with these linkages are:

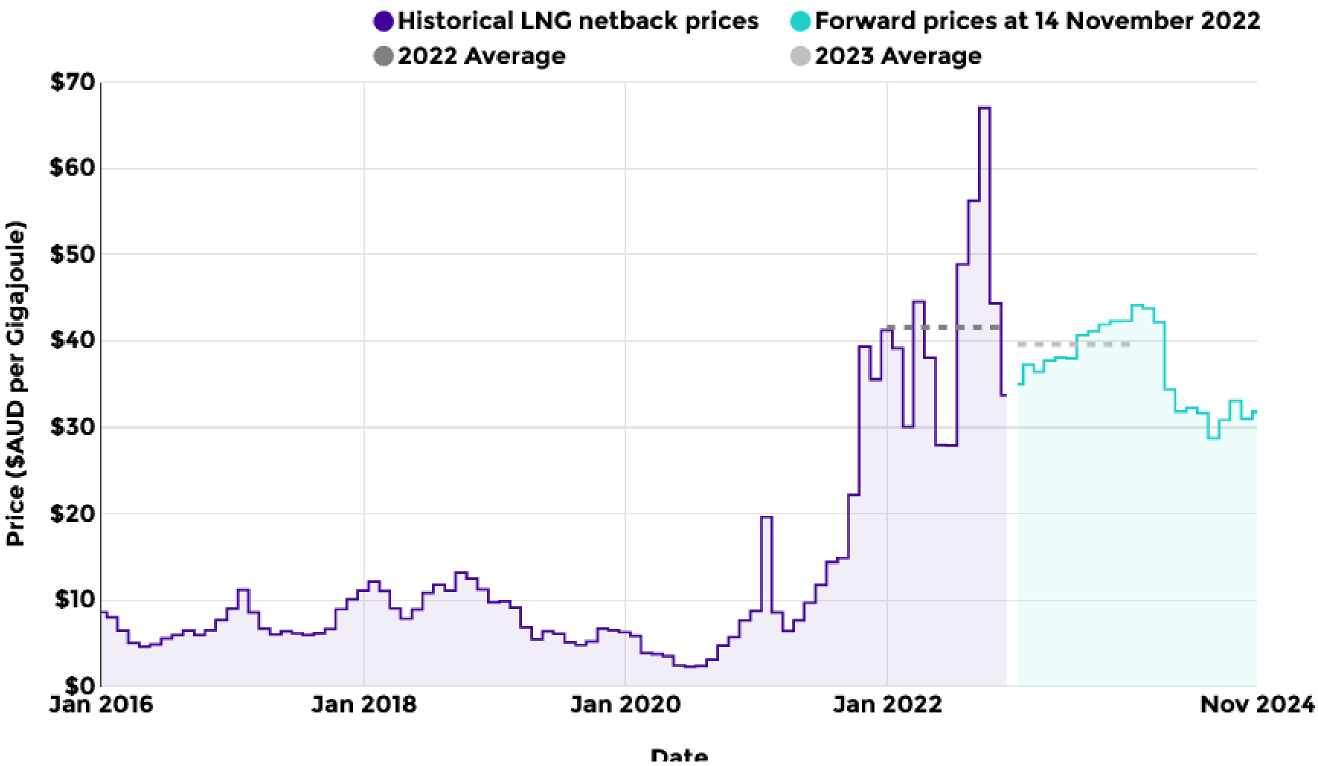
- The time frames for delivery mean that planned flows will tend to be driven by longer term (multiple day) issues rather than quick reactions to within day events.
- Multiple day issues could be relevant during the study period given concerns about the east coast gas supply and demand situation.
- When moving gas between the DWGM and an STTM hub the gas must be scheduled in each market as well as on the transmission pipeline connecting them, meaning that failure to get gas scheduled in one market can have flow-on costs and risks. Any mismatch in what is scheduled could leave a participant or shipper in a situation where it is over-supplying in one market or one pipeline while under-supplying on another, effectively exposing it to imbalance costs in each that are unlikely to offset each other.
- There are different price caps and administered price caps in the STTM and the DWGM, while there are no price caps on gas sold outside of the STTM and DWGM. This means that in tight situations gas flows may tend to move towards the markets with the ability to pay the most for that gas. Similar issues arise with interactions with the NEM, as discussed below.
- The east coast gas markets are now more linked to international markets due to LNG exports. The ACCC publishes information on LNG netback prices, being a measure of an export parity price that a gas supplier can expect to receive for exporting its gas. It is calculated by taking the price that could be received for LNG

and subtracting or 'netting back' the costs incurred by the supplier to convert the gas to LNG and ship it to the destination port.

– Figure 5 shows historic and forward LNG netback spot prices. During winter 2022 domestic spot gas prices reached parity with, and exceeded, the high international netback prices, with this being a factor in prices exceeding the cumulative price caps. The high forward LNG netback prices are dominated by European gas supply uncertainty during the northern winter.

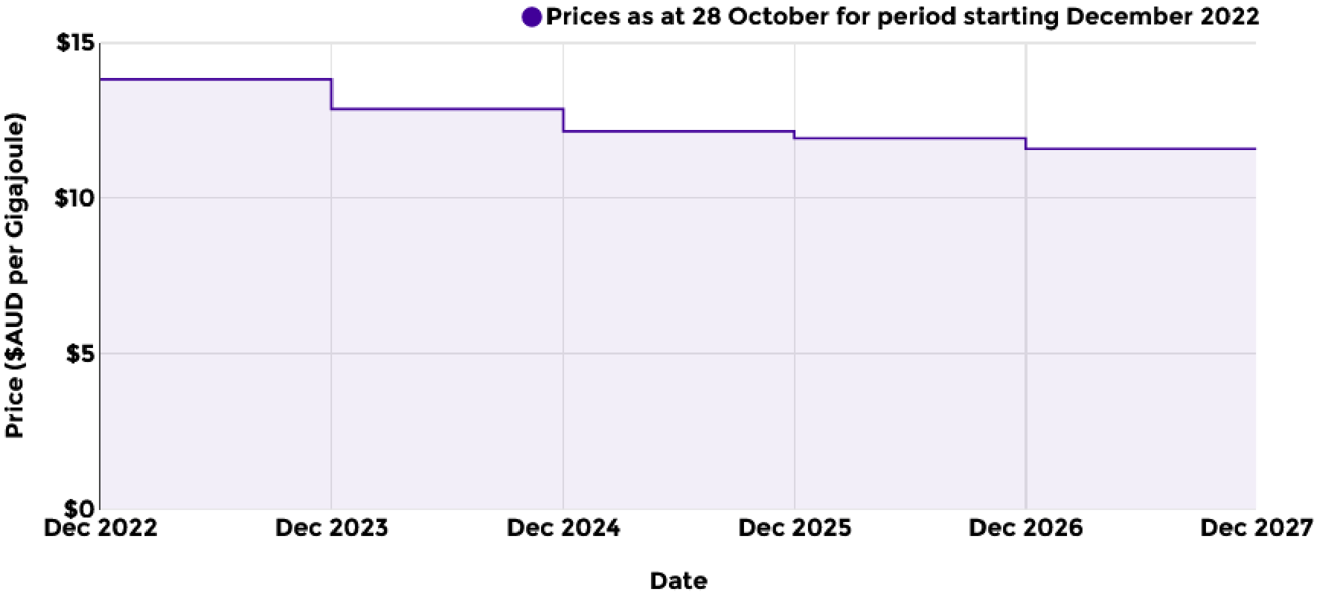
– Importantly, if gas is contracted over the longer term then the average price of that gas will be significantly less than the peak spot values. While there may be multiple views of long term contract prices, Figure 6 shows an ACCC projection of the medium term net-back prices, based on international oil-linked LNG prices, which provides one indicative measure of the value of longer term contracts out to five years.

Figure 5 – Historical and forward short-term LNG netback prices[33]



[33] https://www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-2025/lng-netback-price-series

Figure 6 – Forward medium-term LNG netback prices [34]



Another consideration is that gas flows between markets may not always be driven purely by markets. In emergency events that span states the National Gas Emergency Response Advisory Committee (NGERAC) may become involved. NGERAC comprises officials from Commonwealth, state and territory governments, and representatives of AEMO, gas industry sectors and gas users. The Committee's responsibilities include ensuring consistent management of natural gas supply disruptions across jurisdictions and advising jurisdictions on responses to multi-jurisdictional natural gas supply shortages.

Conceptually, the linkages between gas markets can be simplified from a modelling perspective by focusing on each market individually but considering a range of import and export scenarios for each market.

2.5.2 Linkages with the National Electricity Market

Gas powered generation creates a link between the National Electricity Market (NEM) and the broader gas markets, including the STTM and DWGM. As demand from gas powered generation in the NEM grows:

- Demand for gas in the DWGM and STTM hubs with gas powered generation increases.
- Gas powered generation outside of STTM hubs can impact the quantity of gas that can be supplied to the hub.
- Purchase of gas in the STTM for backhaul to gas powered generators can increase the effective demand in a hub.

Further, when NEM prices cause gas powered generation to commence generating at short notice, there is a risk that the market has inadequate linepack available to serve that generation.

[34] https://www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-2025/lng-netback-price-series

There are also economic links between the markets. Generally, gas powered generators will only operate when the ratio of the electricity price to the gas price exceeds the heat rate of their units (i.e., the rate at which it can convert gas to electricity). If gas prices are elevated due to conditions in the gas market, then electricity prices must be correspondingly high in order to justify purchases for gas powered generation (ignoring any contractual considerations or other considerations). If price caps applied in both the NEM and in gas markets are overly constraining then GPG may withdraw from the market. This scenario is discussed further in the context of winter 2022 in Section 2.6.

2.5.3 Upcoming NEM market design changes

A recently completed review of NEM parameters by the AEMC's Reliability Panel[35] for the period 1st July 2025 to 30th June 2028 had recommended that the level of the APC be increased from $300/MWh to $500/MWh from 1st July 2025. Amongst other reasons, the Reliability Panel considered that this increase would provide for more robust outcomes given the potential for further periods of high fuel prices. This recommendation took account of the current gas APC values. The panel also noted that the $300/MWh value was set when domestic gas and coal markets were more insulated from international markets. Given this, the gas parameter study will use a value of $500/MWh for the NEM APC in scenarios where the NEM APC is assumed to apply.

A rule change submitted by Alinta Energy[36], proposed to increase the NEM APC to $600/MWh with a sunset period of 12 months, to reflect the prevailing fuel input costs. In response to this, the AEMC has recently announced that the value of APC in the NEM to apply from 1 December 2022 to 30 June 2025 will be $600/MWh, a doubling of the prevailing value.[37]

The value of NEM APC is relevant as it supports and increased demand for gas by GPG during NEM administered pricing events. In our study, the value was an input into the construction of bid stacks for gas purchases for power generation for scenarios where that include high electricity prices as a driver of gas market events and outcomes. As there was little difference in gas demand impact of using $500/MWh or $600/MWh we used $600/MWh in all studies.

2.5.4 Risk management in gas and electricity markets

There are differences between approaches to managing risk in gas and electricity markets. Hedging in the NEM is predominately via financial instruments linked to spot market prices, including the Australian Stock Exchange (ASX). On the other hand, hedging in the gas industry tends to be more physical, being linked to holding contracts with producers and with pipeline operators. While the DWGM and STTM facilitate trading around a contract position, the underlying contract is much less freely available. Securing a firm contract may entail making a very long-term financial commitment (multiple years) to pipeline operators and producers. While "as available" contracts can be procured at lower cost, these offer little benefit to the holder at times of peak flow on pipelines as holders of firm capacity are supplied first. Consequently, the risk of a participant wanting to consume gas being unable to secure a contract-based hedge is greater in the gas industry than in the NEM.

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[35] https://www.aemc.gov.au/market-reviews-advice/2022-reliability-standard-and-settings-review
[36] Alinta Energy, Rule Change Proposal - Amendment To The Administered Price Cap To Mitigate The Ongoing Threat To The Reliable Operation Of The Market And System, 1 July 2022.
[37] AEMC - Rule Determination -National Electricity Amendment (Amending The Administered Price Cap) Rule 2022, Proponent Alinta Energy, 17 November 2022

However, the ASX did introduce a futures market for the Victorian market in 2013. Traded volumes were minimal until 2018 when trade picked up, although trading is still rather low, being less than 5% of the volumes traded in the DWGM.[38] The ASX now also now offers contracts at the Wallumbilla Gas Supply hub.

The levels of aggregate contract coverage by participants in gas and electricity is similar. However, small players – such as new entrant retailers – will tend to have a lower level of contract coverage than in the electricity market.

During extended periods of system stress in the electricity industry, contract prices will tend to be high, though contracts will still tend to be available to protect against even more extreme events. In gas, meanwhile, a participant might have to secure capacity from others who already hold it, and there are potential barriers to such transactions due to a lack of a transparent market for pipeline access.

Gas storage is also a risk management tool in gas markets. They allow gas bought at times of low prices by a market participant can be used by it when gas prices become high. Of course, the storage option also allows for arbitrage between market over both time and space.

2.5.5 Implications of linkages to risks in other markets

Short-run risks that arise between markets include:

- Gas supply disruptions in the broader gas markets exogenous to the markets under study cause increased competition for gas that would normally supply the STTM or DWGM. This could give rise to higher-than-usual flows between these markets.
- High electricity prices for a sustained period may require running gas-powered generation for longer durations and/or at higher utilisation, driving gas demand. If markets for both gas and electricity are under stress, there will be a trade-off between shifting the tight supply-demand balance between the gas or electricity markets, depending on whether gas-powered generation is curtailed or not.
- There may be coincident and cascading linked events across markets. For example, an electricity shortfall in Adelaide might cause high gas prices in the Adelaide STTM hub, with this supplied from the DWGM causing high gas prices in the DWGM which in turn trigger a high electricity price event in one or more NEM regions.

Specific scenarios under consideration for inclusion in this review are provided in Appendix A.

2.6 Commentary on winter 2022 events

2.6.1 Introduction

Key factors that contributed to the extreme events during winter 2022 were:

- Extremely elevated prices in international markets for thermal coal and gas.
- Domestic gas prices reaching parity with (and exceeding) international netback prices, after remaining significantly lower than the netback price from August 2021 to April 2022.

[38] Australian Energy Regulator – State of the Energy Market 2021 p196.

- Reduced coal generation availability in the NEM increasing the need for gas generation, and hence putting demand side pressure on gas markets. Coal outages were both planned and unplanned, and there were also coal fuel supply constraints due to flooding events.
- Particularly cold weather further increasing winter gas consumption.

These factors led to extremely tight conditions in both the eastern gas and electricity markets, resulting in unprecedented prices for gas and electricity. As a result, administered pricing has been applied in both the DWGM and the Sydney STTM, as well as in mainland regions in the NEM due to breach of the cumulative price threshold, and the Gas Supply Guarantee was activated by AEMO. Administered pricing was also applied in the Brisbane and Sydney STTM due to a retailer of last resort event.[39]

This section explores some of the impacts of these events and the implications for this review. It should be noted however that:

- This discussion is based on general observations about the event and should not be taken as a detailed review.
- This review focuses on future years and care needs to be taken in extrapolating the specific events of winter 2022 into the future.

2.6.2 Events in eastern gas markets

Driven by the factors above, prices in the eastern gas markets were highly elevated leading into winter 2022. Average prices for Q2 2022 in the DWGM and each STTM hub were all above $28/GJ, compared with average prices of $7-9/GJ for the same quarter the previous year.

Major events were as follows:

- A retailer of last resort event triggered administered pricing in Brisbane and Sydney STTM hubs from 24th May to 7th June – this was the first time a RoLR event has occurred in the STTM.
- Breach of the CPT in the DWGM led to capped prices from 10am on May 30, continuing across June.
- After the RoLR event concluded in Sydney, prices were then capped from 8th to 14th June due to CPT exceedance.
- AEMO invoked the Gas Supply Guarantee for the first time on 1st June, resulting in re-direction of gas for Queensland LNG export to domestic markets.

Later, AEMO issued a series of market notices for the DWGM (e.g., 11th July 2022, 18th July, 2nd August), notifying the market of a threat to system security in the DTS, due to low Iona underground gas storage levels, creating a risk of supply shortfalls due to storage depletion, with this expected to impact the total system.[40] These market notices sought a ceasing of gas purchases from the DWGM via controllable withdrawals, and also for gas withdrawals for gas powered generation to not occur without a corresponding supply injection.

[39] This section is written largely with statistics and outcomes as reported in AEMO's Quarterly Energy Dynamics Q2 2022.
[40] 2022 Review Of The Reliability Standard And Settings. Reliability Panel AEMC, 1 September 2022.

On 19th July, AEMO also activated the Gas Supply Guarantee (GSG) to secure additional gas supplies from Queensland to supply Victoria. This is the second time that the GSG has been triggered. These provisions remained in place until 30th September 2022.

2.6.3 Events in the National Electricity Market

In Q2 2022, the average electricity price was $264/MWh compared with the $85/MWh for Q2 2021. High electricity prices meant that administered price caps were applied in mainland NEM regions from 12th to 13th June due to NEM CPT exceedance, beginning in Queensland. The NEM administered price was then set at $300/MWh.[41] Subsequently, lower volumes of capacity were being made available to the NEM, and resultingly, AEMO resorted to the application of numerous directions in order to operate the power system securely and reliably. Ultimately, AEMO suspended the spot market in all regions from 15th June to 24th June, as well as activated reserves from the Reliability and Emergency Trader (RERT) on three occasions in June.

It is understood that the respective current levels of the APC for both the eastern gas markets and the NEM are such that some generating units were unable to source gas at a cost that could be recovered based solely on the capped NEM prices – put simply, the cost of gas generation may have materially exceeded the maximum NEM prices. To illustrate this point, the marginal generation cost of a GPG can be estimated by multiplying its gas purchase price (in $/GJ) by between 10 and 20 depending on the efficiency of the generator. If gas prices were at $40/GJ due to gas market APC's then, depending on their efficiency, a GPG will only be able to profitably generate on a spot basis if NEM prices are in the range of $400/MWh - $800/GJ. But the NEM price could not exceed $300/MWh because it was capped.

2.6.4 Potential gaps and trade-offs in administered pricing

The events of Winter 2022 highlight some potential gaps in the existing approach to administered pricing across markets.

- The setting of administered price parameters has in the past tended to be very much focused on specific markets in isolation. While general interactions with other markets may be an input, there has been little consideration of the implication of simultaneous capping of multiple markets. While caps have been set appropriately given stable historic levels of gas prices more flexibility in the process of changing caps may be warranted in the future.

- Differences between the level of price caps in the STTM and DWGM have been raised in prior reviews though stakeholder feedback has been that the different natures and context of the markets has been an argument against alignment of the parameters.

- While administered price caps serve to protect the price exposure for consumers for the gas they receive, absent any other measures it can be profitable for those holding surplus gas in capped markets to sell that gas into uncapped markets. The negative consequence of this is to reduce the supply certainty for consumers.

- Administered price caps have focused on addressing relatively short term events that market mechanisms cannot address within a few days. They are not appropriate long term measures in the event of a sustained

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[41] Section 2.5.3 describes future changes to the NEM APC value which are, in part, driven by these events.

increase in the fundamental price of a commodity, as prices need to rise to allow supply and demand to re-equilibrate.

These points highlight trade-offs between risks to consumers, system security, and the operability of markets. There is no single right answer and the best answer may be a combination of how administered price settings work across gas and electricity combined with a range of security measures and new policies.

Based on consultation feedback on our earlier Draft Consultation Report, and noting some of the challenges outlined above, there does appear to be broad support for:

- Future NEM and gas market parameter reviews to be aligned or combined into a single process;
- Greater alignment of the gas market parameters between gas markets, and
- For simultaneous triggering of administered pricing across markets (at least in the context of broader east coast issues).[42] This might best be viewed as a new trigger mechanism across markets that applies in addition to the existing triggers within individual markets.

2.6.5 What about an APC indexed to a reference gas price?

The 2022 Reliability Standards and Settings Review for the NEM raised the possibility of linking the NEM APC to another price, such as the APC in the DWGM, or to the ACCC LNG netback price.

In the context of gas price caps, consideration could also be given to referencing gas APCs to prevailing gas prices via some type of index. This would, for example, avoid the unworkable situation where the commodity price of gas rises to a level that exceeds the value of the gas APC. This would help the market clear and would reduce the reliability of gas supply to those who could afford that gas.

While our analysis considers scenarios with linkage to the world LNG market, we do not propose to explore a dynamic APC value as that is beyond the scope of this review which is focused on setting single values. Further, as we discuss, a dynamic APC value is challenging with respect to consumer cost exposure. This section does however provide some discussion of the issue.

The current APC primarily serves to provide protection against the consequence of short term infrastructure problems or extreme load beyond expectations. An underlying assumption is that the market is in equilibrium, such that supply and demand is aligned with the prevailing typical level of gas prices.

An increase in the underlying commodity price of gas, independent of demand forecasts or infrastructure, beyond APC creates an anomaly in the short to medium term:[43]

- If the situation lasts a few weeks or months then the application of APC makes supply impossible without extraordinary levels of compensation, which still need to be recovered from the market and simply shift the exposure. Though it is important to note that appropriate levels of forward contracting can provide protection if APC is not applied.

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[42] It would make less sense in the context of a temporary local issue in one market that has no material impact on other markets.

[43] If forward LNG netback price predictions show in Figure 5 (above) unfold and the east coast gas market were again to become linked to those prices then gas prices could exceed current APC values.

- If the condition is permanent then over a period of time supply and demand will adjust to that new price and a new APC could be set relative to that new position.

This example shows that the balance between protecting consumers while also maximising efficiency breaks down while a market is reacting to a sudden, significant and permanent commodity price rise. For the market to work at all in the short term it is best that APC be dynamically modified with commodity price (so as to at least provide protection against infrastructure failures or extreme demand) or that it is not applied at all (with high levels of contracting providing protection instead). Ultimately there are limits to how much protection can be provided to consumers through administered pricing if the price rise reflects a reduced ability to supply consumers.

It should also not be assumed that a dynamic gas APC might not of itself create problems. An example of how a dynamic approach could be problematic is illustrated by events in Texas in February 2021.

In February 2021 Winter Storm Uri struck Texas and extremely severe and cold weather resulted in widespread generation outages, very high gas and electricity prices (in turn causing defaults and bankruptcies) and – perhaps most relevantly – the failing of an electricity price cap linked to a gas price index.[44]

There was no single cause of the event. Electricity demand was exceeded forecasts by about 10 GW due to the cold weather, there was failure of gas supply, storage and distribution equipment, as well as of various generation technologies. These events reinforced each other, with some generators unable to receive gas due to freezing of gas infrastructure, while some critical infrastructure was subject to power cuts.

The evolution of gas and electricity prices, and the application of caps to limits prices is instructive:

- With a tight gas supply-demand balance, gas prices were very elevated. Typically, gas trades at prices around $US 2-3/mmBtu (or per million British thermal units), but a gas index which is used as a reference for indexing electricity prices was close to $US 400/mmBtu.
- There was no mechanism to limit gas prices, as there is in Australian gas markets via the APC.
- In turn high gas prices and electricity demand, drove electricity prices to a high offer cap of $US 9,000/MWh (analogous to the NEM market price cap). High prices endured for long enough that a circuit breaker similar to the CPT was triggered. Resultingly, electricity prices were then limited to a low offer cap (analogous to the NEM APC) to protect consumers.
- However, at the time, the low offer cap was to be calculated as the *greater* of $US 2,000/MWh and the natural gas index price multiplied by 50. With the natural gas index above $US 360/mmBtu, this meant the low offer cap would be set at above $US 15,000/MWh, i.e., above the value of the high offer cap.
- The Public Utilities Commission of Texas (PUCT) overrode this, and prices were instead set at the high offer cap.

[44] The Timeline and Events of the February 2021 Texas Electric Grid Blackouts – The University of Texas in Austin Energy Institute, July 2021. The PUCT commissioned this report.

In the aftermath, various changes to the markets offer cap settings have been made. In particular, the low offer cap is now set simply at $US 2,000/MWh, with no reference to the gas price. The high offer cap has also been reduced to $5,000/MWh.

2.6.6 Considerations for this review

The learnings from the events of winter 2022 have been considered in forming scenarios, with specific scenarios added to reflect the broad features of winter 2022. Further, links with the gas parameters to the equivalent parameters in the National Electricity Market are relevant since gas market outcomes - and hence the gas parameters themselves - will strongly influence electricity supply costs.

3 ROLE AND BOUNDS OF GAS MARKET PARAMETERS

3.1 Introduction

It is important to appreciate the relationship between the maximum price in a market – such as VoLL in the DWGM and MPC in the STTM and administered pricing arrangements. This section provides an overview of the roles of the various gas market parameters and the important considerations in setting their values.

3.2 The Maximum Market Price (MPC/VoLL)

VoLL in the DWGM and MPC in the STTM are the maximum market prices in those markets. The maximum market price represents the price at which the market – as a matter of policy – is prepared to accept that it is not willing to pay more to supply demand. It should be set at a level high enough:

- To allow the market to clear in the short run, whether this be through demand response, redirecting supply from one use to another, or for additional high-cost supply to come into the market on a short-term basis; and
- Encourage investment in capacity over time to support the ability for the market to clear.

It is common to try and justify the maximum market price based on some economic consideration of the "optimal" amount of peaking capacity in a long-run equilibrium. That is, over the long term the investment and operating costs of the gas system are perfectly aligned with the value of delivered gas. However, a long-run equilibrium view assumes perfect planning and will tend to imply lower prices in situations where the market is in disequilibrium – as most real markets are most of the time. In effect, a maximum market price based on an optimal long run equilibrium may actually cap prices at a level too low to allow a market to respond to short term situations arising from imperfections in forecasting, planning or investment.

It is appropriate to review the maximum market price from time to time to assure that it is high enough to accomplish its principal objectives but not so high as to cause other problems that are not best dealt with directly. It should be a stable market parameter that is not changed, and particularly not lowered, without a compelling argument that the current value is causing problems that are not best dealt with some other way. In particular, the maximum market price should not be lowered primarily because an inherently uncertain engineering/economic calculation suggests that a lower value might support a hypothetical long-run market equilibrium.

The view taken in this review is that the maximum market price should be high enough as not to interfere with the operation of markets.

The risks of extended periods of high prices should be managed with policies such as the Administered Price Cap (APC) and Cumulative Price Threshold (CPT), and other problems – such as market power for example - should be attacked directly by modifications in the market design or regulatory arrangements.

3.3 The Cumulative Price Threshold (CPT)

A Cumulative Price Threshold (CPT) serves to limit the total amount of revenue suppliers in a market should be able to earn over a cumulative price period before an Administered Price Cap is imposed. The normal logic is to set CPT at level such that investors in peaking capacity can recover enough revenue to justify the investment prior to APC being applied. The cumulative price period is essentially seven days in both the DWGM and the STTM, as it is in the NEM, and the review of that value is outside the scope of this review. In theory if there were multiple CPT events a year then it would not be necessary for owners of peaking capacity to recover all of their costs in one cumulative price period. We assume that investment costs must be recovered during a single a cumulative price period.

While the prices that trigger CPT may be less than VoLL, at $1,400/GJ the CPT in the DWGM would allow only one schedules priced at the VoLL of $800/GJ within a cumulative price period but not two. At $440/GJ the CPT in the STTM would allow only one schedule at the MPC of $400/GJ but not two.

3.4 The Administered Price Cap (APC)

Once the CPT triggers APC then it can be assumed that investors have recovered an adequate return on their investment. APC is intended to be a price cap that – to a great extent – allows trade based on short run costs to continue while limiting profits on peaking capacity.[45] APC acts to limit the financial risk of consumers. The imposition of APC may require some interventions to ensure that supply and demand clear when APC is lower than the natural price that the market would otherwise clear at.

3.5 The bounds on parameter settings

Here we summarise the logical bounds on the gas market parameters to be considered in this review.

- The maximum market price (VoLL or MPC) should be set at level no less than that which the market could be expected to clear at without requiring involuntary curtailment.
- The maximum market price (VoLL or MPC) should not be an impediment to efficient investment, but should not be so tightly defined by that criterion as to restrict investment to mitigate deficiencies in planning or forecasting.
- CPT should be set to a level that would allow reasonable opportunity to recover peak capacity investment costs over the cumulative pricing period (and allowing for revenues earned under normal market operation and subsequently under APC).
- APC should not be set so low as to remove the need for prudent risk management by the demand side.
- APC should not be set so low as to exacerbate issues by having supply withdrawn from the gas market or creating bigger issues in other markets (e.g., due to APC being too low for GPGs to be able to source gas).

In addition, the gas market parameters applied in the STTM and in the DGWM should avoid, where possible, inefficient outcomes between those markets or with the NEM and the broader gas market, e.g., for example, recognising that the gas price is a driver of short-run electricity production costs, the administrative price caps in each market should be set such that incentives to procure gas and produce electricity remain.

[45] Peaking capacity can be viewed as higher cost, less frequently used, sources of gas used in extreme demand situations, such as locally stored LNG or contingency gas.

4 THE PARAMETER ASSESSMENT PROBLEM DEFINED

4.1 Introduction

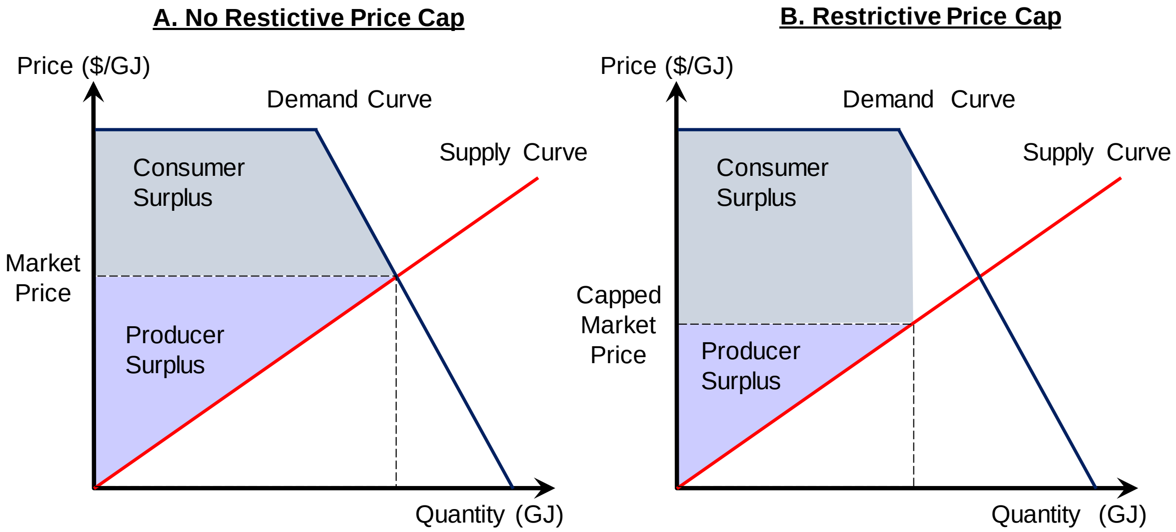
This section provides a summary of the problem that must be solved to test alternative parameter settings and provides the rationale for it. A parameter setting includes a value for VoLL or MPC, as applicable, a value for the CPT and a value for the APC.

4.2 Efficiency vs market risk

The core objective is to explore the trade-off between market efficiency and market risk. The primary measure of market efficiency is the sum of consumer and producer surplus.

Figure 7 illustrates the concept of market efficiency and the impact that price caps can have on it.

Figure 7 – Market efficiency, consumer and producer surplus, and the impact of price caps



Consumer surplus is the amount by which the total benefit consumers receive from gas exceeds what they must pay for it. Producer surplus reflects the total amount by which payments to suppliers exceed their costs.[46] Case A in Figure 5 shows a situation where the market clears without being restricted by a price cap. The market price is set at the point where the supply and demand curves intersect, and this is the point at which the sum of consumer surplus and producer surplus (i.e., total surplus) is maximised.

Case B illustrates the impact of capping the market price below the price where the market would otherwise clear. Suppliers have little incentive to supply gas which costs more to deliver than the capped market price allows or on

[46] Once involuntary curtailment occurs APC will apply anyway. Consequently, this assessment is limited to situations where involuntary curtailment is not required. As uncontrollable withdrawal will be unchanging with price, but the impact of varying price caps applied to uncontrollable withdrawals will dominate consumer surplus, we exclude the fixed amount of uncontrollable withdrawal from the consumer surplus calculation. However, we will track any involuntary curtailment that occurs in our simulations as that will indicate that the situation represented by the scenario is too extreme.

which they cannot earn a profit[47], so the total quantity of gas made available may be restricted. While the consumers actually supplied benefit from a lower price, the reduced gas supply means that the sum of consumer and producer surplus is lower and market efficiency is reduced. A higher price cap will tend to alleviate this problem and improve the total surplus.

On the other hand, less restrictive gas market parameters (i.e., higher price caps) increase the risk of participants in the market to the extent they are exposed to the market price. Exposed participants must buy expensive gas to fulfil their obligations to retail gas consumers, or to support their own industrial or commercial use of gas.

The measure of market risk used in this study has been used in all studies since 2013.[48] The measure of market risk of a firm (or participant) is the number of days it would take firms of various sizes to recover the total lost profit from an event. The 2013 review concluded that a CPT event cost of more than 500 days of foregone gross operating profit, relative to normal profits absent an event, could reflect a level of risk that is unmanageable and excessive for participants and allowing for variations in the level of hedging.[49] Hence the measure of market risk is defined as the ratio of the profit lost by the firm, and the firm's average daily profit, in turn defined by the total annual profit of the participant divided by 500 days, or:

Days Lost Profit= (Profit Lost)/(Average Daily Profit)

Each participant is assumed to consume an average of 1 TJ/day, and both retailing participants, and industrial users are considered.

- For gas retailers, the application of an average price and a typical gas retail margin enables calculation of the average daily profit.
- For industrial users, the implications associated with the use of 1 TJ of gas are more complex. Using available ABS statistics, we can estimate the range of intensity of energy use across industry groupings, calculate the revenue associated with that gas use and determine the average daily profit. The calculation of lost profit is slightly more complicated. For each participant type the same calculation method applies in determining the profit from the base case and the profit available in the scenario case, except that the quantity and price in each case will be different according to the context/scenario. As a result, each of these profit estimates will differ from the average daily profit and each other.

In previous reviews of gas market parameters, the loss of more than 500 days' worth of profit as a result of an extreme pricing event was taken to represent the point where the risk exposure of a participant becomes unacceptable, creating the potential for participant insolvency. The same threshold is proposed for use in this study. This standard applies to all participants equally.[50] Some participants, such as industrial users, face a

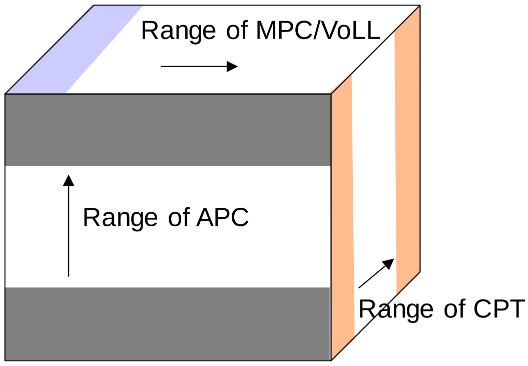
[47] Under administered pricing the gas markets do offer cost-based compensation for suppliers scheduled with costs higher than APC. However, suppliers are not guaranteed to have their costs compensated fully and may prefer to move the gas to other markets or to other days (where they can get a profit). Suppliers also may not want to reveal their costs.
[48] DWGM CPT Review, AEMO, 2013.
[49] Normal market risk is the responsibility of participants to manage so the role of the gas market parameters is not to control risk arising from protracted industry disruptions. If current market conditions were to become embedded and form a new equilibrium, the lost profit standard will be relative to profits obtained in that new equilibrium. Accordingly, we propose to continue to adopt the 500 days lost profit as an appropriate measure of unacceptable risk when applied to gas market events in the context of an equilibrated market.
[50] There are differences in balance sheet structure between the many participants in the gas market that may lead to different conclusions about the level of loss that could be sustained by each participant type.

different risk relative to retailers when curtailment occurs, however the evaluation of curtailment costs is beyond the scope of this report. Therefore, the risk for all participants is the risk of obtaining potentially inflated quantities of gas, but at a greatly inflated price.

4.3 The grid of gas market parameters

Our methodology requires the assessment of both market efficiency and risk exposures for different gas market parameters. As we will only be considering discrete combinations of gas market parameters, we refer to the set of considered gas market parameters as a forming a grid of gas market parameters. This grid, including the limits imposed by bounds, is illustrated in Figure 8.

Figure 8 – The grid of gas market parameters



For each parameter and combination of gas market parameters, the minimum and maximum value parameters in the grid are defined by the economic and logical bounds described in Section 3.5. Within the set of considered parameters we will include the current settings for each of the STTM and the DWGM[51]. It is necessary to also consider sets of parameters with no CPT or APC applied for a given VoLL/MPC to provide a reference case of a market with no administered pricing and hence the maximum market efficiency achievable.

4.4 Assessing gas market parameters

The performance of a given set of gas market parameters can be determined by simulating those gas market parameters across a range of situations. In each case the level of relative market efficiency and the degree to which risk exposures for a range of participant types can be assessed. By varying the key setting in the scenarios, the sensitivity of each parameter setting can be assessed.

A strongly performing set of gas market parameters would consistently produce higher market efficiency in different situations while maintaining an acceptable risk exposure for all represented participant types. If a set of gas market parameters were to perform very well in some cases but very poorly if the scenario were slightly varied (e.g., under a sensitivity analysis) then that would make that parameter setting less attractive. If the current gas market parameters are found to be in the strongly performing set of possibilities that would suggest that change is unwarranted. However, if the current gas market parameters perform noticeably less well than others than that would suggest grounds for change.

The proposed methodology for solving this problem is described in the next section.

[51] And to keep consistency between the markets in the modelling we will include the case where each market is simulated with the current parameters of the other.

5 SOLUTION METHODOLOGY

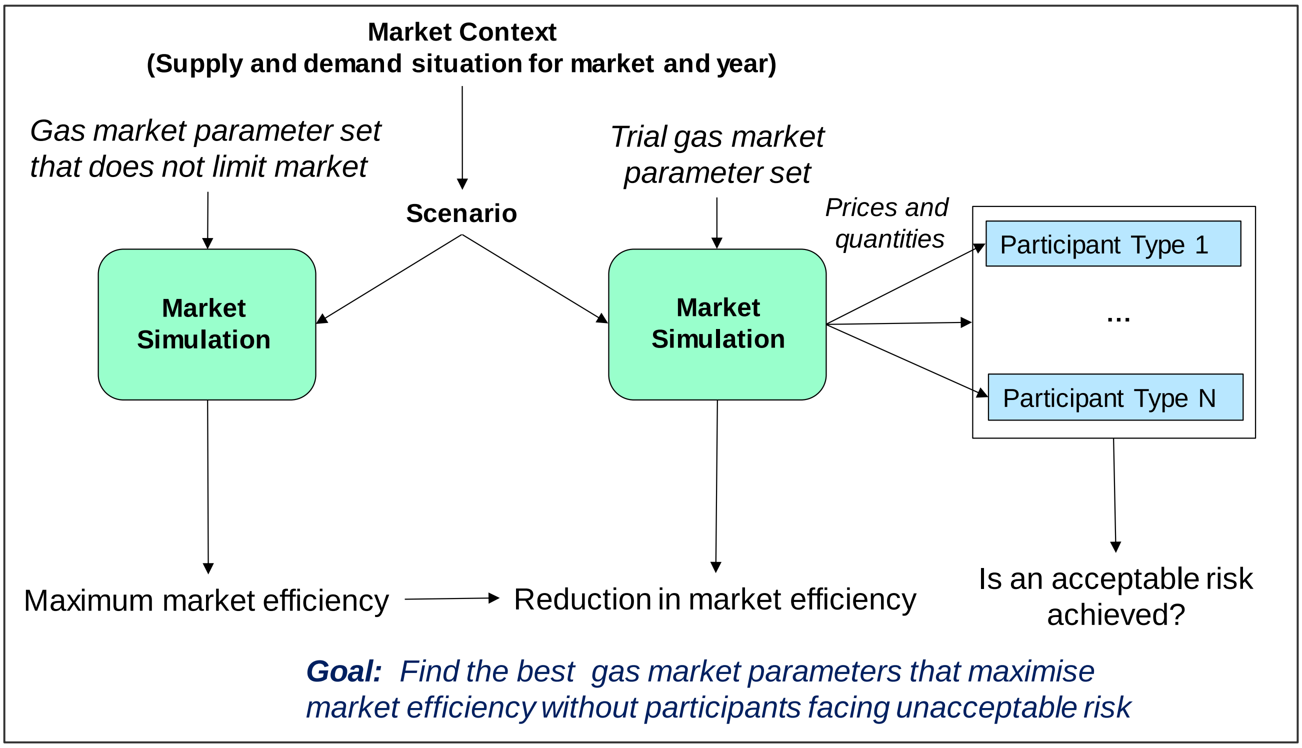
5.1 Introduction

The previous section described the structure of the parameter assessment problem. This section describes how we solved that problem.

5.2 Overview of the methodology and model

Figure 9 provides an overview of the solution methodology for the parameter assessment problem defined in Section 4.

Figure 9 – Overview of the methodology



The key concepts in Figure 9 are:

- A market context describes a specific market, in a specific year with some specific supply and demand conditions. For example, this could be the DWGM in 2023 with the supply and demand figures as forecast by the Victorian Gas Planning Report.
- A scenario represents a specific event that happens in that a market – such as production problem or some the impact that a broader gas market issue has on the market under study.
- The range of gas market parameters from the grid of parameters includes:
  - A set of parameters that does not limit the market. This set will have different values of VoLL/MPC but no administered price cap will apply. This will correspond to the maximum market efficiency case, though the risks for participants may not be acceptable.

  - A broader range of alternative parameters with different levels of CPT and APC for a given setting of VoLL/MPC.

- By simulating the market context across the event represented in the scenario, and for enough time to work through the flow on effects of the cumulative pricing period, we can assess the market efficiency and participant risk exposures for the different parameter sets. The simulation of the event only considers the week leading up to the event to initialise the cumulative price for the context in which the event occurs and the period over which administered pricing applies.

- For a given VoLL/MPC the set of gas market parameters that does not limit market efficiency was used as a reference point to determine the loss in market efficiency for each parameter set with the same VoLL/MPC but with APC and CPT imposed.

- For each occurrence of APC, two variations of participant behaviour was considered. One variation was a "truncated variation" with market response modified to reflect the lack of willingness to offer into a capped market when cost is above the cap. This simply means that the supply of gas that would otherwise be offered at a price above the value APC is assumed not to be available to the market. The second variation is a "no-response" variation in which supply and demand curves are unchanged by the imposition of the APC.

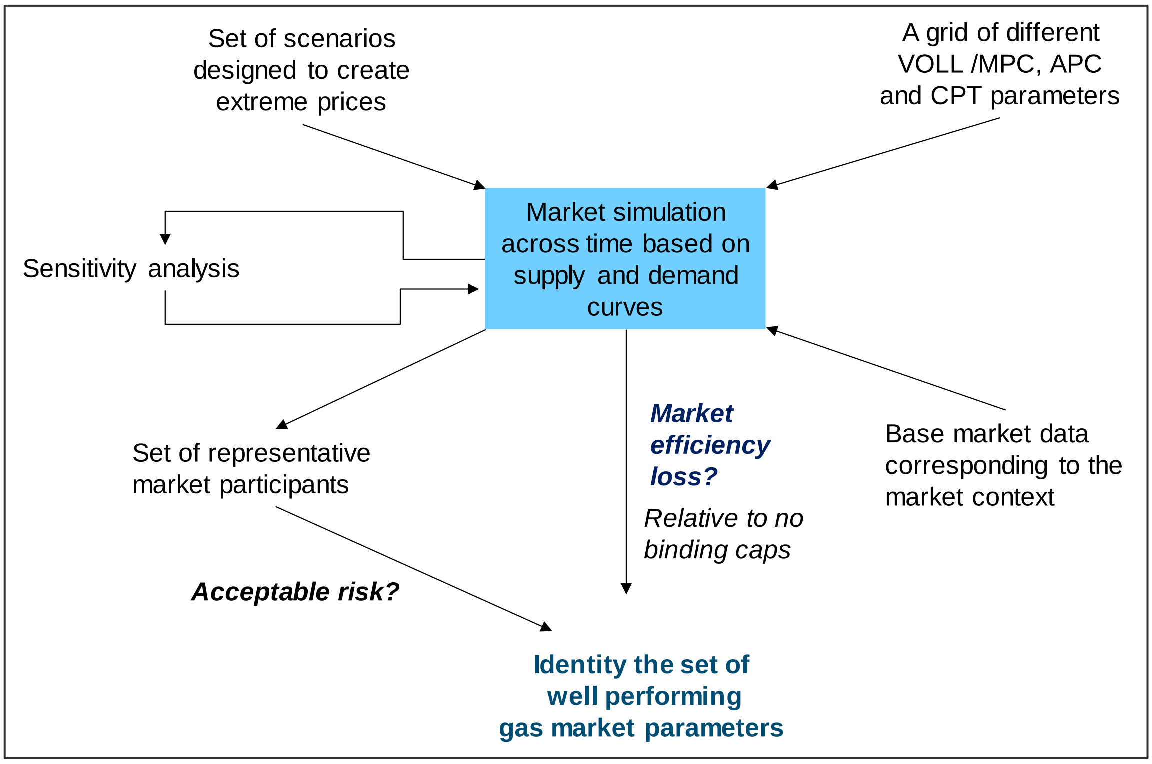
- This analysis will also indicate if VoLL/MPC values are too low and interfering with the short run market.

- Given the parameters, and the resulting prices and quantities, we can assess the risk exposure for a range of hypothetical representative participants. This was assessed relative to an estimate of their profits derived by simulating the market context without the scenario occurring (not shown).

- The goal is to find those parameter settings which perform best in terms of minimising the reduction in market efficiency while maintaining acceptable risk. Effectively, we seek those combinations of gas market parameters that perform best across all scenarios.

A range of different modelling components that were used to implement this methodology are shown in Figure 10.

Figure 10 – Modelling components



The key components are:

- The market context.
- The scenarios.
- The market simulation.
- The representative market participants.
- The sensitivity analysis.
- The calculation of market efficiency loss.
- The calculation of the acceptable risk.

These components are described in the remainder of this section. We also discuss the relationship between investment and the bounds on the gas market parameters.

5.3 Market context

The DWGM and STTM hubs during the study period were different from today and will evolve across time. For this reason, it was necessary to recognise in this review that the markets will be in different states at different times. This concept is reflected in the market context.

It is important to simulate a market in different market contexts so as to ensure that the results of the review are robust for these different contexts. For the current gas parameter review, these contexts were informed by AEMO's defined Progressive Change and Step Change scenarios (described earlier in Section 2.2).

A market context of a given market was created by starting with the current market and evolving it based on forecast changes in the market. The simulations were based on daily supply and demand curves so the practical realisation of market context is that that the shape, extent and prices in the supply and demand curves will change, reflecting:

- Underlying demand;
- Available supply capacities;
- Prevailing import and export levels;
- Injection and storage limits; and
- Levels of contracting (which will essentially be defined by the above considerations).

Each market context, without any extreme events occurring, was simulated to provide a base reference point for what the profits of participants would be normally. This was contrasted with cases where extreme events are imposed on the market context, in the form of the scenarios described in the next section.

5.4 Scenarios

Scenarios describe a sequence of days including some extreme event days that we anticipate will result in extreme pricing, such that MPC/VoLL may be achieved and/or APC triggered. A scenario will effectively be represented by a different set of market supply and demand curves from those that would normally apply. These will form input to the market simulation. During the simulation of the market these supply and demand curves may be further modified if APC applies.

The reference point for assessing the impact of a scenario was a simulation of the base market context without any scenario imposed. This base market context simulation allowed the profitability of different participant types to be assessed. This informed the analysis of acceptable risk.

Scenarios were defined relative to a specific market context – this allowed the DWGM and all of the STTM hubs to be separately represented in event situations that are more tuned to the context of that market. The scenarios explored are presented in Appendix A.

The first day of a scenario is an event day. Prior to this it is assumed that no administered price cap has been in place and that normal base market context conditions have prevailed. This allows the CPT calculation to be initialised with data.

Two sets of day types were considered within the period of the scenario:

- Generic base market context days. These have normal base supply and demand curves. However, if APC is triggered then in the truncated variation of the simulation these curves were modified to reflect the withdrawal of supply and demand response that is dependent on a price exceeding APC.
- Event days directly impacted by an event, e.g., reduced supply from a production facility or very high exports. For these days, the supply and demand curve were modified to reflect the event and any market response that may occur. If an event lasts multiple days such that the administered price cap applies then within the simulation further modifications may be applied to account for the withdrawal of supply and demand response in the truncated variation.

The scenarios are presented in Appendix A. These scenarios are adaptations of those applied in the prior review. The core data has been updated to reflect the supply, demand and in structure arrangements in the future, including a mix of GSOO Progressive Change and Step Change scenarios. The major changes to our scenarios are listed below:

- To reflect decreased Longford production the Gippsland supply interruption scenario, we replace a long-duration 50% outage of Longford with a short but full outage of Longford.
- To reflect greater compressor redundancy around Melbourne we have moved a compressor failure case to a pipeline supplying Victoria.
- To reflect declining supply in Victoria, we have changed one interlinked market scenario so that flow is towards Victoria rather than away from Victoria.
- We have added a new scenario across the DWGM and two STTM hubs (SYD and ADL) that reflect a situation with increased international prices across oil, coal and gas.

All our scenarios are focused on winter as higher winter heating demand will always produce more extreme outcomes than if the scenario were to happen at another time of year.

5.5 Market simulation

The market simulation comprises a model that primarily determines schedules and prices given a supply and demand curve that reflects what can be delivered or withdrawn from the market on a gas day. The purpose of these simulations is to allow the assessment of performances of different gas market parameters. Effectively, we seek that combination of gas market parameters that perform best across all scenarios.

A similar simulation model was used for both DWGM and STTM. There were slight differences between them:

- The DWGM can have five prices determined for a gas day while the STTM normally has just two (ex-ante and ex post) plus a third if contingency gas is used on the gas day.
- STTM contingency gas prices are determined by identifying the price in a piece-wise linear contingency gas offer curve (derived from typical contingency gas offers) that corresponds to the volume of gas required.
- The DWGM cumulative price is calculated each time a market clearing price is determined, as the sum over the prior 35 schedules (including the latest) of the greater of:
  - The market clearing price for that schedule, and
  - The maximum value of any offered gas that is constrained on (i.e. is priced above the market clearing price) in the operational schedule. In the simulations we only consider the use by AEMO of LNG with the volume and price specified as input data based on the nature of the scenario.
- The STTM cumulative price is determined whenever an ex ante price is calculated and is the sum of a hybrid priced determined for the last seven days (including the day the latest ex ante price is determined). This hybrid price is required as the cumulative pricing process draws on data from three gas days. For day d the hybrid price is defined as the sum of:
  - A(d+1), being the ex-ante price for the next gas day (d+1),

- B(d), which is zero unless contingency gas is scheduled for gas day d by the time the ex-ante price is determined for day d+1 (which is when the CPT calculation is performed), in which case B(d) is the positive amount by which the contingency gas price for gas day d exceeds the ex-ante price for gas day d, and
- C(d-1), representing the positive amount which the greater of the ex-post imbalance price and the contingency gas price[52] for gas day d-1 exceeds the sum of B(d-1) and A(d-1). In practice, if an event occurs during the gas day we assume that the contingency gas term dominates the ex-post imbalance price, such that only the former is considered in this calculation. If the event occurs prior to the ex-ante price being determined for that gas day we assume no contingency gas is used and that the ex post imbalance price equals the ex-ante price such that C(d-1) = 0.

In running the simulation an 'event' that triggers high prices could occur at any schedule, but at least one week of 'normal' market clearing processes were simulated before an event, to initialise the case allow for calculation of the cumulative price.

We did not explicitly model different conditions for every schedule across the day. Rather, normally no more than two schedules were explicitly represented. One was the first schedule of the sequence (the ex-ante market in the STTM or the start of day scheduled in the DWGM) and this was by default duplicated at each schedule applicable to that gas day. This first schedule could be an event or a normal schedule. If the situation changes during the gas day – either an event ends or starts – then a second scheduled applies for the remainder of the day. Thus, a surprise weather event in the DWGM could be represented as a normal schedule for the 6 AM, 10 AM and 2 PM schedules, then an event schedule – with increased demand but with no additional supply available from supplies distant from Melbourne. In the STTM contingency gas use can be triggered during the gas day on the first day of an event. If the event continues into subsequent gas days then the event is assumed to be reflected in the ex-ante price without further contingency gas being required.

During periods for which administered pricing applies, a special case arises in the running of schedules if APC is triggered. Once APC is applied to a schedule then in the truncated variation the base bids and offers applicable were modified to account for withdrawal of supply and demand response due to the application of APC. This can lead to a third schedule type.

Events always occur on a Monday and the simulation continued to run for two more weeks, ending on the second Monday after the event.

The supply and demand curves were generated by combining bids and offers associated with different segments of the market as outlined below.

The demand curve was formed from bids for:

- Uncontrollable withdrawal (i.e. price taker demand) excluding GPG demand. For the purpose of scenario definition, this was apportioned into industrial/commercial and domestic load.
- Gas powered generation demand (with a maximum price linked to what would be viable in the NEM). GPG bids are estimated as a function of NEM prices and then converted using heat rates into equivalent bids based on gas prices. The NEM price is a parameter of the scenario which will typically reflect standard pricing

[52] Included to cover the scenario where contingency gas is called on day d after the CPT calculation has been run, so that its effect is accounted for on the next day.

but in key scenarios may reflect pricing up to and limiting the NEM market cap. We do recognise some bids for gas that appear unprofitable because evidence in the market suggests they exist and may reflect contract positions or the existence of storage opportunities.

- Exports from the market.
- Contingency gas (in the STTM).
- Price sensitive load (including contingency gas). Where appropriate this was also apportioned into industrial/commercial and domestic load.

The supply curve was formed from offers for:

- Production facilities.
- Storage facilities (varying with the current level of storage).
- Contingency gas (in the STTM).
- Imports to the market.

There is assumed to be no net linepack change between the start and end of each schedule. The STTM hubs have little useable linepack. For the DWGM modelling of linepack has been dismissed because of the lack of locational and inter-temporal modelling within the day and there is no obvious basis for defining bids for linepack – in the real market it is scheduled to be at the same minimum level each day and this cannot be violated.

Each bid and offer from which the demand and supply curves are formed was in the first instance based on current market data (see Section 6). In the STTM offers were truncated at the hub capacity, while in the DWGM they were limited based on pipeline point constraints that restrict the total volume deliverable over a day.

Export bids, GPG bids and import offers were increased or decreased as required by the broader gas and electricity market context as required by scenario.

The level of hedging also has to be accounted for. Participants that are both suppliers and consumers tend to offer low (mostly near $0/GJ) and bid high (rising to near MPC/VoLL) to ensure that their supply is matched with their demand (though in practice the demand curve is not that price responsive). If that result is achieved then the participant has no exposure to the market price on the matched volume. The same effect can be achieved by independent participants who achieve that effect through contracting. Offer curves (and to the extent relevant, demand curves) can be modified into the future to maintain their general shape relative to the prevailing contract volume and expected gas market price. Expected equilibrium positions are established using the LGA gas price projections accompanying the 2022 GSOO. Base year offer curves are then shifted forward to match equilibria in the study years. The shape of each curve is preserved by decomposing the curve into the following sections; "below expected equilibrium", "at expected equilibrium", and "above expected equilibrium". The "at expected equilibrium" section of the offer stack is transposed to maintain its position relative to the expected equilibrium in the forward year, while the other two sections are stretched or compressed to maintain the offer curve structure, albeit focussed on a different expected equilibrium. This procedure is carried out at the level of each offer stack as its purpose is to correctly characterise price and quantity response during a scenario.

The above procedure implicitly assumes contract positions will adjust to maintain relativity with market participants' long-term assessment of market conditions. Recently, due to extraordinary circumstances, contract levels may have not adapted to the current market context, but this shock will either resolve as circumstances will retreat to previously observed normality, or if the current situation persisted, contracting would be expected to adjust to reflect the new market equilibrium.

Separately, when analysing outcomes at the participant level we independently consider a wide range of contractual positions that individual participants might have when assessing the effect of each parameter set on market participants. This is discussed in the next section.

5.6 Representative market participants

We do not simulate individual participants within the market simulation. Instead, we focus on the settlement outcomes for generic representative market participants who are likely to have material risk exposure in one or more of the scenarios we simulate. As we do not consider specific participants, we consider a range of participant types and, within each participant type we define several participants to ensure the full range of participants considered encompasses a wide range of actual market participants.

The participant parameters adopted considered the following participant types:

- A small market customer (who purchases directly from the wholesale market) who may have a less sophisticated approach to risk management than a retailer;
- Gas retailers with varying contract positions, retail margins and customer portfolios;
- Gas and electricity retailer who could be impacted by events in both the NEM and the gas industry;
- Industrial users, covering a representative spectrum of gas intensity; and
- Gas powered generators;

For each of those participant types we consider a range of:

- Basic Structure (as applicable by participant type):
  - Retail margins;
  - Residential and Industrial customer profiles; and
  - Gas intensity as share of cost structure;
- Contracting behaviour:
  - Differing premium levels relative to spot; and
  - Hedging levels, both as a fraction of total demand and as a fraction of peak demand, spanning from little hedging to highly hedged.

Collectively, the above enable calculation of standard profitability metrics, the exposure through structure or incomplete hedging to gas prices and the implication of scenarios for each type of participant.

Basic participant profitability is defined by retail margins. The cost of gas is composed of a combination of spot and contract purchases, with the latter attracting a premium. Participants with less sophisticated risk management are assumed to only hedge a proportion of total gas usage, while more sophisticated users will hedge a demand following proportion of total gas use. The relationship between profitability and gas cost is further defined by the proportion of total costs attributed to gas purchases.

Each generic participant type has different behaviours in the spot market. For example, a GPG was represented as bidding in the gas market to secure gas at a price consistent with economic operation in the electricity market and would operate whenever it can secure gas and profit from it. By contrast, small retailers were price takers in the gas market. Data for participants remained fixed with respect to the market context, with the exception of an adjustment to account for changes in contract premiums resulting from changes in the overall balance of supply and demand in future years. The level of contracting held by a particular participant was also assumed fixed for that participant across all cases.

When a scenario occurred, the response of each participant accounted for the influence on participant profitability of the incidence of growth in various demand components. Each participant had its demand apportioned between each demand category so, for example, a small retailer with a high percentage of domestic consumers faced increases in price and quantity on a very cold day, whereas an industrial user only faced price increases. Accordingly, the static CPT load factor employed in previous studies to evaluate the increase in demand during a CPT event is no longer required.

In total, more than 60 participants were considered, covering a wide range of actual and potential future market participants. In the previous study, analysis was focused on participants deemed to be most impacted by changes. In recognition that the current market may not be near a long term equilibrium state, we have adopted to explicitly consider a more realistic set of participants that should be tenable and will drive participant risk analysis, as well as an additional set, for information purposes that are designed to reflect the reality of entry under current circumstances. This last group are not determinative of the parameter settings as the current market context does not represent the expected market state for the study period.

5.7 Sensitivity analysis

Sensitivity analysis was conducted to assess how much the results of the simulation change for a change in the inputs. The purpose of this analysis is solely to ensure that the results of the modelling are stable given small changes in the modelled data. We focus on simple changes around varying fixed demand and varying supply costs as these variations explore the region around the standard solution.

- An increase in uncontrollable demand of 1%. This reflects a tighter supply and demand situation.
- A decrease in uncontrollable demand of 1%. This reflects a more relaxed supply and demand situation.
- An increase in all supply curve prices of 3% but with no change in quantity. This reflects a high cost structure. The increases would be capped at the applicable price cap.
- A decrease in all supply curve prices of 3% but with no change in quantity. This reflects a lower cost structure.

5.8 Calculating market efficiency

The market efficiency for each simulation solution was taken as the area under the demand curve relative to the demand cleared less the area under the supply curve utilised. The market efficiency loss for a case was the difference in the market efficiency between it and a reference case which is identical except that no administered price cap was applied. Noting that uncontrollable withdrawal is conventionally priced at VoLL / MPC, for the purpose of assessing market efficiency, we did not apply different VoLL / MPC values to the uncontrollable withdrawal as this would introduce variations in market surplus without demand changing. Instead, we assumed a common value of uncontrollable demand across all cases.

Ideally, market efficiency measures would be based on the true costs and benefits of participants in the market as actual bid and offer curves may reflect a number of considerations other than the simple benefit or cost of gas, such as the need to adequately hedge, limitations on bidding behaviour, and potentially strategic behaviour could distort bids and/or offers.

Market participant trade relative to a contract or hedge position. It can be argued, however, that bids and offers formed relative to a contract position are a valid measure of participant costs and benefits simply because by submitting those bids and offers they are indicating what they would require to be paid or would be prepared to pay at the volumes associated with those bids and offers in the presence of risk. The bids and offers effectively internalise all the costs and benefits associated with contract costs and hedging, making them more representative of the full range of costs and benefits applicable to a participant. There are other reasons why the actual bid and offer data may be distorted. For example, the demand curve is by definition limited to VoLL/MPC. Some participants may bid at a higher price if allowed. Also, strategic behaviour could be reflected in bids and offers, distorting them.

An alternative measure of market efficiency loss can be determined by comparing market efficiency between cases with the same APC and CPT settings but different VoLL/MPC values. This gives insights into the impact of different VOLL/MPC values.

The difference between observed offers and bids and actual benefits and costs may or may not be significant in general terms but for the evaluation of a particular set of parameters they are not likely to be significant. The primary process undertaken assesses market parameters against a set of market outcomes, each corresponding to a scenario, and then compares the results to identify appropriate parameter settings. While individual solutions may contain inaccuracies through the use of market-based bids and offers, these inaccuracies are common to all cases so the distortionary effect should be minimised given that the analysis is based on the difference between surpluses.

Simulations performed of the 2019 base context yielded prices and market clearances that were consistent with actual results arising from the market in 2019. As the parameters were evaluated based on forecast prices and quantities, the simulation should reflect our best estimate of what will happen. In projecting forward, we implicitly assume the same market behaviours are observed in future years, albeit in the context of different forecast supply and demand conditions. For example, offers are assumed to align with contract positions in the same way as in 2019. The result being that, within the limitations of the assumption of continuation of 2019 bid and offer strategies, the forward year is a projection of the same behaviour and also simulates a representative set of the distortionary effects currently present in actual bid and offer data.

Finally, we note that arguments regarding the true level of VoLL are neutralised by assuming a fixed value higher than any contemplated parameter setting. As the involuntary curtailment of load will automatically trigger an administered pricing state we checked for any simulation outcome for which involuntary curtailment occurred. No instance of this happened, but if it had happened we would have excluded such outcomes from our analysis, eliminating the potential for impact on market efficiency to rely on the level of VoLL.[53]

[53] Where necessary, scenarios were tuned to avoid such outcomes.

5.9 Calculation of acceptable risk

The calculation of lost profit resulting from a scenario is measured by deducting the profit earned in a particular market context, from the profit that would have been earned absent the event. The profit earned in a particular scenario day depends primarily on:

- Participant quantity,
- Prices for the day concerned, and
- Participant contract positions.

Each participant considered has a normalised 1TJ quantity of gas consumption per day. During a scenario, depending on the reason for the scenario and the nature of the participant, this quantity may be adjusted. For example, in response to cold weather, domestic gas demand may increase so that retailers will experience increased demand for gas relative to a standard day according to the assumed proportion of their business that relates to domestic demand. Conversely, an industrial user will not use more gas as their underlying process remains the same.

Within the overall framework of hedging, participants seek to hedge gas costs on an intraday basis. In the DWGM, participants are assumed to bid their daily demand in the first schedule. Where an event occurs that was not anticipated, there are implications for pricing in later schedules although these will not affect daily profitability unless in conjunction with quantity changes, leaving the participant only partially hedged for the day. Where the event continues, the first schedule of subsequent days will reflect price increases. In the STTM, a similar philosophy applies. Participants bid their estimated demand in the ex-ante market and are only exposed relative to that initial position when prices and participant quantities change. In the STTM higher prices are reflected in exposure to contingency gas. Prices In future periods, an ongoing event will leave participants exposed higher prices.

Aside from intraday hedging we assume participants also have standing contracts. These are specified by two parameters – the percentage of gas purchased under contract which assists in establishing the average daily profit, and the gas contract quantity as a percentage of peak gas consumption. Where a participant is exposed to high prices intraday, or unable to hedge high prices in the first schedule or ex-ante market on subsequent days, they are still protected by long term arrangements that fix the price paid on the contracted portion of their gas consumption. Considering peak demand, the percentage of peak demand contracted, and the quantity risk resulting from the scenario we calculate the uncontracted portion of the participants gas demand which is exposed to the full market price.

This portion of the calculation preserves factors related to the context of the scenario such as the season, for example. This ensures that the amount of lost profit is assessed against the appropriate norm, and not a generic day.

Average normal daily profit is defined as an annual average of profitability, which varies between participants and industries. For example, large end-users of gas who are buying gas directly from the market have inherently different margins and cost structures than gas retailers.

Unlike for the calculation of lost profit, the average daily profit is not dependent on the seasonality or timing of a scenario, and an average measure is appropriate. For the purposes of this calculation it is also important to take an industry-wide and long-run perspective. This implicitly assumes that participant returns are close to long-run averages but to not do so will result in significantly different (and even nonsensical) parameter settings to restrict losses to a year's profit when profits are low (or negative).

Participants are considered to be prudent profit maximising business that understand and manage their own risks. While the purpose of the Gas Market Parameters is to limit the risks to market participants, the risks of a VoLL/MPC price or a period of prolonged prices still exist in the market. It is expected that participant will undertake steps to manage these risks appropriately (i.e. through hedging). Therefore while participant may have any level of hedging, it is not prudent for the market to seek to set parameters to mitigate risks for "risk-taking" (i.e. unhedged) businesses.

In the CPT reviews since 2013[54], the acceptable level of risk was defined as 500 days lost profit for a demand side participant who is 50% hedged. Although other factors are no doubt relevant, we assume that defining acceptable risk in this fashion is suitable for other market participants such as large commercial/industrial users. The currently applied standard is the current benchmark for comparison between reviews, enabling one set of analysis to be compared with previous analysis without the standard shifting.

Participants' lost profit in days are calculated for each scenario and across the parameter grid. Those parameter sets that represent risk in excess of 500 days lost profit for a 50% hedged participant are rejected. The participant set deliberately includes participants who are more or less than 50% hedged to provide some sensitivity around the implications of a parameter choice.

However, the acceptable level of risk for a demand side participant remains a matter of judgement. That judgement is delivered by the market participants, who ultimately finance entry or investment after a process of due diligence. The lost profit standard effectively provides that process a worst-case single scenario outcome on which to assess an investment proposition. It is not immediately clear that parameters based on this standard have hampered entry on the demand side in the past, providing no definitive case for decreasing the standard. It is also unknown whether an increase in the standard, effectively introducing more risk to the demand side would be detrimental. Without clear evidence that such a move would not be disruptive, it may not be prudent to consider an increase in the lost profit standard.

Nevertheless, our analysis presented later provides additional sensitivity around the 500-day target.

Finally, we note the lost profit calculations and the associated standard relate to demand side participants. We also implement a separate test for the suitability of the parameters on the supply side, which we discuss next.

5.10 Investment and the grid of gas market parameters

The incentivisation of investment is an important consideration when implementing price caps and often these models adopt a long run equilibrium analysis in which investment is part of the solution of the model. Section 3.2 explains the limitation of using long run equilibrium analysis and argues that VoLL and MPC must necessarily be higher than the values implied by such limits.

Here we focus on the investment cost relative to the revenue available during an event.

[54] DWGM CPT Review, AEMO, 2013.

The normal process for estimating investment costs reflect consideration of the cost of constructing additional capacity, allowing for a required rate of return for similar investments. The analysis must reflect the full cost of investment as economies of scales mean that costs change with investment size.

We did not explicitly model or calculate investment costs due to the complexity of doing so. Rather we adopted an approach similar to that employed in other reviews:

- Using investment costs, required rates of return and an assumed event frequency such as the 1:10 years frequency adopted in previous studies to represent the relative frequency of one from a range of scenarios eventuating, estimate the investment return that is required per event per tonne of capacity.
- Alternate investment types will have different cost recovery requirements during peak periods, different ratios of capacity to output and, due to differing replenishment processes, different limitations on the fraction of stored gas that can be output and replaced
- Given assumed variable and fixed cost structures and utilisation, the profit requirement can be transformed into a revenue requirement per tonne of capacity built that relates directly to prices and price caps.
- Considering the revenue available during an event as a function of market parameters we are able to assess whether a particular set of market parameters support investment.
- We conducted sensitivity around many investment parameters to assess the impact of assumptions of event frequency, utilisation rates and cost recovery proportions.

Broadly speaking the profit available in an event is governed by the CPT, although it is influenced by all three parameters under consideration. If a participant has a suitable cost structure or does not face binding storage restrictions during an event, that allows significantly greater profits while under APC and they will earn more than the CPT in each event. Similarly, the relationship between the CPT and VoLL/MPC will dictate how many VoLL/MPC periods will be registered in an event.

The STTM hubs are not directly comparable to the DWGM due to their different context. The original analysis of STTM settings[55] suggested that the lower MPC (and hence CPT) would not at that time be detrimental to investment in the context of the STTM.

[55] STTM Market Settings Analysis, MMA, 2009.

6 KEY DATA USED IN REVIEW

6.1 Introduction

In this section we identify the data used in this review and map it to the inputs of the model. The principal documents referenced are:

- Gas Statement of Opportunities for Eastern and South-Eastern Australia, AEMO, March 2022, including LGA Gas Price Projections.
- Victorian Gas Planning Report Update 2022.
- AEMO website: www.aemo.com.au.
- State of the Energy Market 2021, Australian Energy Regulator, 2nd July 2021.
- Gas Inquiry, 2017-2025, Interim Report, ACCC, July 2022.
- ABS, Australian Bureau of Statistics.
- DWGM - CPT Review Final Report (DCPTR), AEMO, September 2013.

In many instances, the data available was in the form of a forecast , in which case we have adopted that forecast. In other cases, the data represents a base line and further extrapolation was required.

6.2 Supply and demand data

6.2.1 Demand forecasts (excluding GPG demand)

The scenarios were defined with respect to the AEMO forecast scenarios "Progressive Change" and "Step Change" which have different implications for demand in future years. For the DWGM, demand forecasts, excluding GPG demand, were based on Tables 11/12 in the updated 2022 VGPR with baseline data for 2019 provided from Tables 8/9 of the 2019 VGPR. For the STTM, demand forecasts for each node were obtained from Table 5 of the 2022 GSOO, with baseline data provided from the 2019 GSOO. In both cases the demand in the DWGM and STTM hubs was assumed to change relative to 2019 data in proportion to the rate of change of these state level figures. Both 1 in 2 (i.e. average) and 1 in 20 (i.e. peak) demand day data was used.

6.2.2 GPG demand

Base GPG price responsiveness was based on an analysis of NEM GPG electricity production and demand data and NEM prices for the period 1 June 2019 to 31 August 2019. Capacity and heat-rate data was sourced from NEM Generation Information November 2019 as well as Tables 12 to 16 of Fuel Resource.

Growth in GPG generation over time took into consideration changes in gas-fired generation capacity, with data sourced from NEM Generation Information July 2022.

6.2.3 Gas supply changes

For the DWGM the primary source of information was Table 19 of the VGPR 2022 Update. This provides data for Victorian gas fields through to 2026. Data beyond 2026 was extrapolated to 2027. The final values used are shown in Table 2.

Table 2 - Assumed peak day available production (TJ)

DWGM SUPPLY SOURCE	2023	2024	2025	2026	2027
Gippsland	666	654	615	496	438
Port Campbell	476	476	476	476	476

6.2.4 Historic market bid and offer data

Gas market bid and offer curves were derived from historic data for 2019, focusing particularly on the high-demand winter week commencing 29th July, and for the Brisbane hub the high-demand summer week commencing 6th January, with this data being available from AEMO reporting. 2019 was chosen as a reference year to avoid temporary changes in supply, demand, and contracting behaviours due to the covid pandemic.

For the DWGM bids and offers for the 6 AM schedules were used. For the STTM hubs the ex-ante bid data, MOS stacks and contingency gas offers were used. Bids and offers were adjusted for future years and scenarios as follows:

- Non-price responsive demand was adjusted based on demand applicable to the scenario.
- Storage through put was adjusted with demand.
- Contract levels were adjusted based on the available supply and bids and offers were shifted relative to those new contract positions.

6.2.5 Pipeline and facility capacity

Because the simulation does not model pipelines and storage capacity explicitly, restrictions that would normally appear in such a model must be incorporated in the supply and demand curves.

For the STTM hubs we applied the pipeline capacities supplied by AEMO as the maximum facility capacity at each STTM hub. These values are shown in Table 3. This capacity will supply GPG in the hub (Swanbank in Brisbane and Colongra in Sydney) and any GPG backhaul from the hub.

Table 3 – Maximum Pipeline Capacities for STTM Hubs

PIPELINE	STTM HUB	CAPACITY (TJ/DAY)
Moomba Adelaide Pipeline (MAP)	Adelaide	241.0
SEAGAS Pipeline	Adelaide	226.0
Roma to Brisbane Pipeline (RBP)	Brisbane	189.3
Eastern Gas Pipeline (EGP)	Sydney	335.0
Moomba Sydney Pipeline (MSP)	Sydney	446.0
Newcastle Gas Storage (NGS)	Sydney	120.0
Rosalind Park Production Facility (ROS)	Sydney	29.0

In general plant and pipeline capacities are assumed to be constant over time, apart from announced expansions.

6.3 Participant profitability data

The profitability calculations for each participant type are based on the data in Table 4. The terminology used in this table is discussed further in the following sub-sections. Participant data has not been selected to represent any specific current participants. A variety of participant characteristics have been assumed to cover the possibility of new or different types of participants, or participants of existing type with different operating models.

Table 4 – Participant Profitability Data

METRIC	NEW ENTRANT	RETAILER (SMALL)	RETAILER (ESTABLISHED)	INDUSTRIAL PARTICIPANTS	INTEGRATED PARTICIPANTS
GAS PRICE DATA					
Average Spot Price	$10	$10	$10	$10	$10
GAS HEDGING DATA					
Proportion of peak demand hedged	10%-70%	30%-90%	30%-90%	30%-90%	30%-90%
Proportion of demand hedged	10%-70%	30%-90%	30%-90%	30%-90%	30%-90%
Contract premium	8%-14%	6%-7%	5%-7%	5%-7%	5%-7%
COMMERCIAL DATA					
Residential fraction	60%-90%	10%-80%	10%-80%	0%	10%-90%
Industrial fraction	10%-40%	20%-90%	20%-90%	0% (Retail)	10%-90%
Gas cost fraction (Residential)	30%	30%	30%	0%	30%
Gas cost fraction (Industrial)	70%	70%	70%	100%	70%
Gas cost fraction (Participant)	30%	27%-34%	25%-32%	10%-40%	25%-32%
Profit Margin	5%	8%	9%	10%-20%	7%-15%

The range of values considered are shown in the table for a range of participant types:

- Retailers, though we have separated this group into the following:
  - New entrants who are entering the market in its current context
  - Retailers or participants that are smaller or less sophisticated in risk management terms. This category would also include new entrants into a market near long term equilibrium.

  - Retailers who are established in terms of contracting, business structure and efficiency.

- Industrial Participants, who buy from the wholesale gas market; and
- Integrated Participants, who both supply and consume gas (and who may also operate in the related markets).

Profitability data was based the range of customer profiles described in the DCPTR review. Information on industrial users is based on data from ABS.

6.3.1 Gas price data

Determining the normal profitability of a participant requires information on the average spot price of gas and the average contract price. An average spot price of $10/GJ was assumed across the study period.

6.3.2 Gas hedging data

To determine hedging performance in each scenario, the relevant metric is the level of hedging as a percentage of the peak demand/gas purchase. For retailers and industrial participants, the range analysed is from 10%-90% with generally higher hedging levels associated with established retailers, while hedging levels decrease with less risk management sophistication, for entrants and particularly for new entrants in the current market. For integrated participants we extend this range to the case where production capacity covers all contracts written. In each case the range chosen is to demonstrate a wide range of participant impacts.

The overall profitability of a participant depends in part on the proportion of gas demand hedged throughout the year. We consider a range of value from 10%-90% depending on the participant type, noting similar biases as mentioned above apply.

Gas that is purchased on contract may attract a risk premium. As noted, we have included a category of participants corresponding to new entrants in the current market context who are more vulnerable than those who would enter in an equilibrium situation, where contract availability and pricing fully reflect the market context. In the current context, there are limited hedging opportunities and those that are available attract a higher premium.

For new entrant retailers, entering the market in its current context we adopted a 5% margin to reflect a less mature and efficient set-up. For retailers that are relatively new entrants we adopt a retail margin of 6-7%. For more established retail participants, we used the 8-9% to reflect more established operational, marketing and management functions. These values surround the value used previously, which originated from the DCPTR review.

6.3.3 Commercial data

For a particular scenario, the customer profile of a participant will influence participant profitability and exposure to risk. For retailers and integrated participants, a wide range of proportions are considered to account for consumer focussed participants through to commercial focussed participants.

We have adopted the same cost of gas percentage assumed in the last review, supported at that time by the DCPTR review. We assume the cost of gas represented 30% of the total gas contract price for a typical residential gas contract, and we have adopted that value. This reflects higher marketing and other costs in dealing with smaller users. The share of gas costs for commercial contracts is much higher at 70%, reflecting lower transaction costs for larger customers. The Gas Cost Fraction – Participant is a measure of the share of total costs gas comprises for each business. For retailers and integrated participants, this is an average of the gas cost proportions of residential and commercial customers, weighted according to the share of each in their customer portfolio.

Industrial users are their own end-users and do not on-sell gas. Instead they produce a range of products for which gas is an input. The proportion of gas used by industry can be calculated as the ratio of industry energy consumption ($) to industry total revenue ($) as presented by the ABS. The average gas use intensity by industry is typically very low, however we consider 10%-40% to reflect individual firms significantly exceeding sector average gas penetration.

Given the cost information, this implies the revenue associated with one GJ of gas given a particular customer mix. While participants with the same customer mix also will have the same revenue amount, it is necessary to calculate the retail margin based on individual cost structures. For industrial users, the ABS provide information on profit margins by industry categories. These typically range from 10%-40%. The latter figure was for the mining industry so in keeping with the requirement to focus on business' most susceptible to risk we considered the modified range of 5%-20%.

6.4 Base supply and demand curve data

The process of generating a demand or supply curve for use in the simulation begins with historical bid and offer curves. These are available by schedule for both the DWGM and the STTM (including MOS stacks), enabling selection of the appropriately daily/seasonal characteristics required for a particular scenario. This basic data is available directly from the AEMO website.

This data was modified at the level of bid and offer data to reflect future conditions.

Gas powered generation projections will need to be converted to have some price sensitivity relative to the electricity market. This was based on the heat rate conversion of gas to electricity.

Adjustments of supply and demand were based on the GSOO and VGPR. The ACCC also forecast future gas production by region along with assessment of future gas production by region which can be used as a further reference.

Because the simulation does not model pipelines and storage capacity explicitly, restrictions that would normally appear in such a model must be incorporated in the supply and demand curves. Information on STTM hub capacity and DWGM pipeline injection limits can be sourced from AEMO. In the case of exports, the AER State of the Market Report provides information on gas pipeline transmission capacities which will provide the base reference data for limitations on transfers between markets. These were updated based on current predictions of requirements as described in the GSOO.

6.5 Scenario adjustments

Bids and offers were adjusted for scenarios based on the following information:

- High demand days will typically be based on 1:20 forecasts.

- Storage offers need to be revised based on the level of storage in the scenario. Historic data will inform the typical behaviour for high, medium and low storage scenarios, though some scaling may be required to reflect prevailing future market prices and quantities.
- Contract data adjustments were based on maintaining patterns in historic data but moving the reference point in (primarily) the offer curves to account for changing contract position.

Aside from the data used to develop input supply and demand curves we have also used other historical data such as price and scheduled data to verify various modelling functions are accurate.

6.6 Curtailment cost data

Average revenue at risk data is available from the ABS by industry grouping. This measure may be employed when validating a potential VoLL setting. Effectively we are verifying that VoLL settings are high enough to not restrict market clearances based on actual economic costs as this would lead to poorly rationed gas. We did not find evidence among the industries we studied that the VoLL values under contemplation were too low to allow legitimate valuation of gas in those industries.

6.7 Participant profitability data

Participant profitability data is used to discern how many days profit is lost when an event occurs. In previous studies which only included retailers it was a relatively simple calculation based on the assessed average retail margin for retailers.

In considering industrial customers with profitability linked to production rather than just gas consumption, we require additional profitability data. The Australian Bureau of Statistics (ABS) has profit margins detailed by industry and these provide guidelines for defining the range of profit margins we consider when analysing participant profitability. In similar fashion we will cross-reference profit margins with energy use by industry from the same source. Given both we can develop a range of participants reflecting the range of different industries consuming gas. For each of these participants we can calculate proportion of cost attributable to gas and then the total revenue/GJ from the profit margin for industrial use of gas.

6.8 Investment cost data

There are a number of investment options that could be considered when assessing the feasibility of market-based investment in Australian gas markets. These include new/expanded pipelines, import terminals and LNG facilities, such as that in Dandenong. For the purposes of this exercise we do not seek to predict or forecast investment, merely to assure the chosen parameter set would support a reasonable investment option.

While there is a lot of data on gas pipelines, these are peculiar to the specifics of each facility. Similarly, there are some options for coal seam gas, although this is not a realistic option for the DWGM. These investment forms are unlikely to provide the immediacy of response that is available from a dedicated storage facility close to the point of delivery.

Prior reviews considered that an LNG facility in Melbourne (or an STTM hub) was the most logical option for covering peak demand conditions. With the emergence of LNG receipt facilities as a favoured option – with Port Kembla under construction near Sydney and plans for a receipt facility for Victoria – this seems a viable technology with a lower cost than a facility like Dandenong. While the ability of an LNG receipt facility to reliably supply gas is dependent on timely arrangement of delivery of LNG by ship, this is a not significantly different from the limitation on a Dandenong type facility that gas must have been stored in the past. However, as the main challenge facing the east coast is availability of gas, an LNG receipt facility does provide a way of introducing additional gas from outside of the region.

Key details of the Port Kemba facility are: [56]

- It can delivery up to 115 PJ per year, varying from 120 TJ/day in summer (1 liquification train) to 500 TJ/day in winter (2 liquification trains).
- It would have 4 PJ of storage in a floating storage unit (about 10 to 12 days' worth of supply).
- Supply can be maintained through a consistent rate of shipments arriving.

Table 5 provides investment cost data for an LNG receipt facility.

Table 5 – LNG receipt investment and operating expense assumptions[57]

ASSUMPTION	INPUT VALUE
Capital Cost	$250-300 million
Storage Capacity	4 PJ
Daily Production Limit	300TJ/day-500TJ/day
Expected Life of Facility. Note: Floating storage unit may have salvage value. The operating life has been set to reflect zero emissions targets.	25 years

In assessing the suitability of Gas market parameters for investment recovery, consideration was given to other the existence of other income streams available to the facility. This was represented by a capacity factor for the investment that reflects the extent to which the investment generates other revenue stream that effectively offset the cost of providing the required service. This was achieved through adoption of a parameter to define the proportion of total cost recovery that would be expected to be associated with profitability during an extreme event. We conducted sensitivity analysis around this parameter setting.

When considering the expected life of the facility, the initial lifespan is estimated at 30 years. Noting the evolution of zero emissions policy, we have conservatively reduced that to twenty years operation in the mode intended. Finally, we consider the possibility of salvage value. To allow for this consideration we consider that although the facility use may be truncated due to zero emissions policies, we allow a further five years of project life to account for the residual value of the project, or alternative uses beyond the initial twenty year period. Collectively these adjustments suggest an equivalent expected life of 25 years, with the commensurate cost recovery required over that timeframe.

[56] Data sourced from Port Kembla Gas Terminal Volume 1Environmental Impact Statement, November 2018 and Port Kembla Gas Terminal Proposed Modification Submissions report, January 2020, Both reports by GHD.
[57] Data taken from https://ausindenergy.com/wp-content/uploads/2019/04/PKGT-EIS.pdf, https://www.gem.wiki/Port_Kembla_FSRU, with initial analysis supported by https://iopscience.iop.org/article/10.1088/1755-1315/150/1/012026/pdf and https://www.aer.gov.au/system/files/VENCORP%20report%20November%2005.pdf

The marginal component of investment determined after adjustment for other operational uses is then developed to provide a return requirement based on the WACC.

Table 6 shows a weighted average cost of capital (WACC) based on calculations used in prior reviews but with updated values.[58]

Table 6 – Weighted average cost of capital parameters

PARAMETERS	ESTIMATED VALUES
Average nominal risk free rate	3.01%
Inflation	3.00%
Debt margin	2.00%
Market risk premium	6.8%
Debt funding	40.00%
Equity funding	60.00%
Corporate tax rate	30.00%
Effective tax rate for equity	30.00%
Effective tax rate for debt	30.00%
Equity beta	1.0
Cost of equity (nominal post-tax)	9.8%
Cost of equity (real post-tax)	6.6%
Cost of debt (nominal pre-tax)	5.0%
Cost of debt (real pre-tax)	1.9%
Post-tax Nominal WACC	7.88%
Post-tax real WACC	4.72%

There are a number of potential investors in this market. The actual WACC of an investor will depend greatly on the investor so these parameters are only representative of the range of investors, and not any specific investor

[58] Based on AER Rate of Return Instrument 2022, RBA Statement on Monetary Policy August 2022.

or investor type, including the owners of the Port Kembla project. As such, we have adopted a neutral stance to some parameter settings. For example, it is not possible to characterise a credit rating for a generic investor, and the equity beta, while it could be calibrated to the industry, has been set to unity as, depending on the nature of the entrant's business, this type of investment could represent taking on a new risk, or hedging an existing risk. It may be seen as a standalone investment in the gas industry which would attract an industry beta, or it could be a large industrial user from another industry hedging their own business to some degree. In general, we expect entry by participants with the lowest WACC, so the bias is towards identifying minimum entry requirements rather than setting a standard by which all participant types could enter. In making those assessments we must also be aware that the assessment is with respect to the performance of the investment during a scenario over relatively few days and is not an assessment based on general operations. For these reasons, comparison with other projects in an overall sense may not be appropriate.

6.9 The grid of gas market parameters

The base grid of gas market parameters considered in this study are described in Table 7. We show the current values of the parameters, the grid points used in the prior study and the grid points proposed to be considered in this study.

Table 7 – Proposed gas market parameters

PARAMETER	CURRENT VALUE	GRID POINTS (PRIOR STUDY)	GRID POINTS (THIS STUDY)
Market Price Cap (MPC) Value of Lost Load (VoLL)	STTM $400/GJ DWGM $800/GJ	Both markets: $400/GJ, $600/GJ, $800/GJ, $1000/GJ	Both markets: $400/GJ, $600/GJ, $800/GJ, $1000/GJ
Administered Price Cap (APC)	STTM $40/GJ DWGM $40/GJ	Both markets: $40/GJ, $60/GJ, $80/GJ	Both markets: $30/GJ, $35/GJ, $40/GJ, $60/GJ, $80/GJ
Cumulative Price Threshold (CPT)	STTM $440 DWGM $1400	Both markets: $1000, $1200, $1400 $1800, $2500 STTM only: $440, $600	Both markets: $440, $600, $800, $1000, $1200, $1400, $1600, $2000, $2500 Subject to CPT exceeding VoLL/MPC.

Some observations on the grid points follow:

- The prior review had the STTM parameters set to the lowest values in the set of grid points. This has made it desirable to consider lower APC values ($30/GJ and $35/GJ) in case problems are found with the current value.
- We doubt that MPC/VoLL settings below $400/GJ will be supportable so have not included these.
- The "normal" gas price will be higher in the future than at the time of the last review, so that will immediately make current CPT levels more likely to bind. Therefore we include some moderate increases in CPT value to account for these increases.

6.10 The NEM administered price cap

A value of $600/MWh for the NEM administered price cap was used in the during the study period. It was used in scenarios that assume APC is applied in the NEM, with the application of APC having a limiting impact on GPG gas demand. While the value of APC is due to drop back to $500/MWh in mid-2005, the actual impact on GPG gas demand was sufficiently trivial that we used $600/MWh in all cases.

7 FINDINGS

7.1 Introduction

In this section we present the study findings that inform our conclusions and recommendations.

Each combination of market context, such as a particular market/hub in a particular year, combines with a scenario and a particular set of pricing parameters to define a case. Relevant subsets of the case results are aggregated to produce the range of results presented in this section.

Section 7.2 presents the simulation results, which give information on both the market efficiency and financial exposure of retailers and industrial users across different years and market contexts for each set of gas market parameters.

Section 7.3 presents results and sensitivities around the impact of different gas market parameters on investment. That analysis serves to indicate a lower bound on the acceptable gas market parameters. However, as the analysis assumes a specific technology and is based on relatively simple assumptions, this lower limit should be viewed only as a guide, rather than a hard limit.

Section 7.4 discusses inter-market linkages.

Section 7.5 provides commentary on current high gas prices.

Section 7.6 discuss the scope requirement of consideration of early implementation (were there to be a change).

Section 7.7 concludes the analysis of the set of acceptable gas market parameters.

7.2 Simulation Results

7.2.1 Scenario results

In this section we summarise the behaviours of the scenarios simulated.

The study period has many competing developments which ultimately made the results relatively consistent between years. Declining gas production is mitigated by anticipated investments, such as at Port Kembla, pipeline capacity increases, and declining demand in the form of either "Progressive Change" or the steeper decline assume in the "Step Change" scenario. Although we contemplate the late delivery of Port Kembla in one scenario, the others are based on the anticipated pipeline of investment and naturally would be susceptible to deviation from that.

The scenarios used in this study are relatively extreme by design. Accordingly, the pricing outcomes are generally outside the range experienced in current day to day market operation. Most scenarios involve a number of coincident individual issues, one of which is the general level of demand. As a result, prices leading into an event vary from slightly heightened levels of around $10/GJ through to levels exceeding $20/GJ. The price impact of subsequent events in the scenarios vary in intensity and longevity between scenarios. The intensity of the price impact in each scenario can be assessed using the average and maximum prices attained, relative to VoLL/MPC across the scenario.

Figure 11 - Average and maximum uncapped price (DWGM)

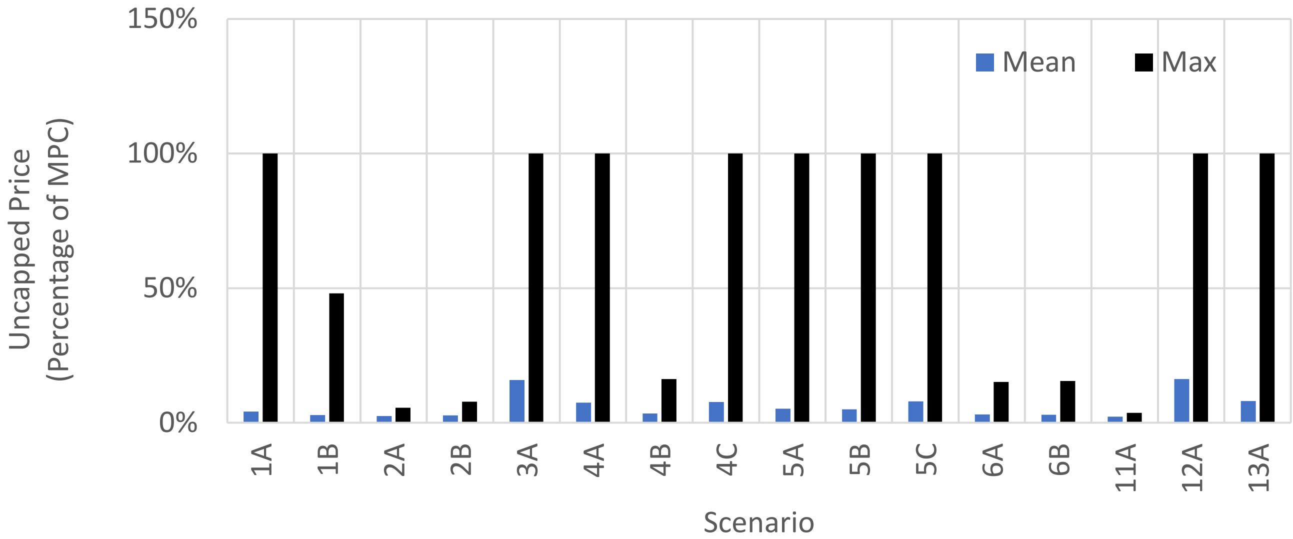
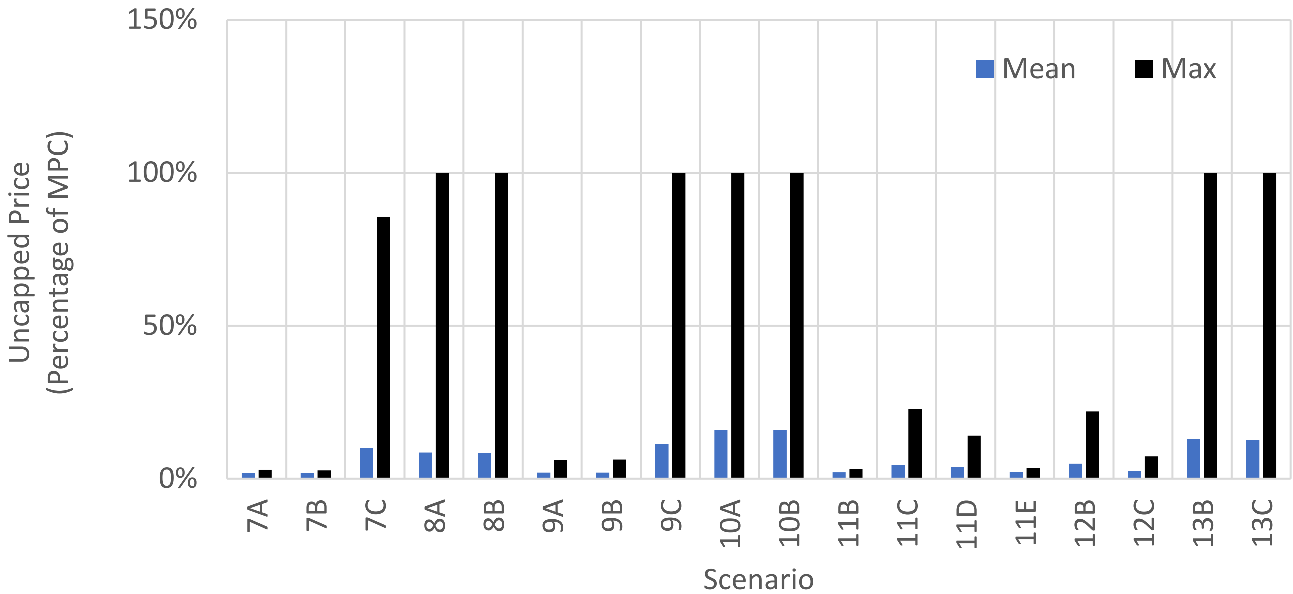


Figure 11 and Figure 12 show the average and maximum uncapped prices attained for each scenario in the simulation as a percentage of VoLL/MPC for the DWGM and STTM. In most DWGM scenarios the event causes the price to reach VoLL, although this depends on market context.

Figure 12 - Average and maximum uncapped price (STTM)



A number of STTM scenarios are not sufficiently extreme (relative to projected available supply) to make the price reach the MPC, or for the cumulative price threshold. For scenarios 7A and 7B model a 50% reduction in flow on the MSP, but this does not result in particularly high prices (see further commentary on this value below). However, in scenario 7C, based on the same event, but also including Port Kembla being delivered late, the price reaches approximately 90% of MPC for some grid combinations. In general, many of the STTM scenarios benefit from future investment and demand reduction that mitigates the impact of traditional motivating factors for administered pricing events.

In a number of cases, the price reaches the MPC for a sustained number of periods, sufficient to breach the CPT. Once triggered, the APC limits prices to a lower upper limit than would otherwise apply until the administered pricing period ends. For each scenario, Figure 13 (DWGM) and Figure 14 (STTM) show the average number of days for which the CPT is breached and the applicable APC limits prices, providing a measure of the typical longevity of pricing implications of the event. Note that for the DWGM, there are five periods per day, so if for example, APC is applied for six periods, this would be 1.2 days.

Figure 13 - Number of days for which the APC is applied (DWGM)

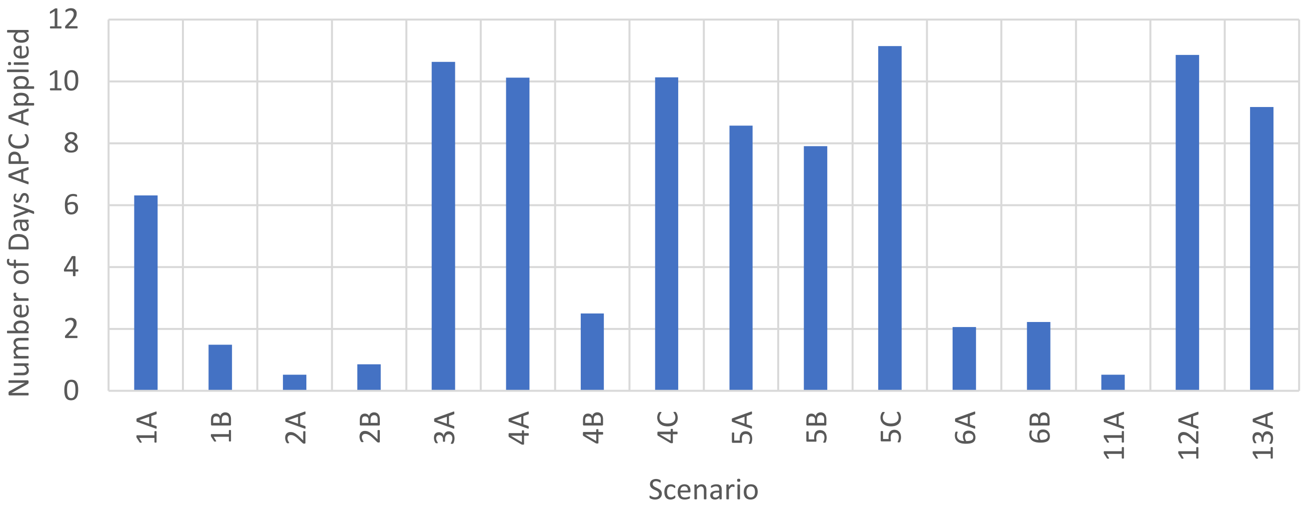
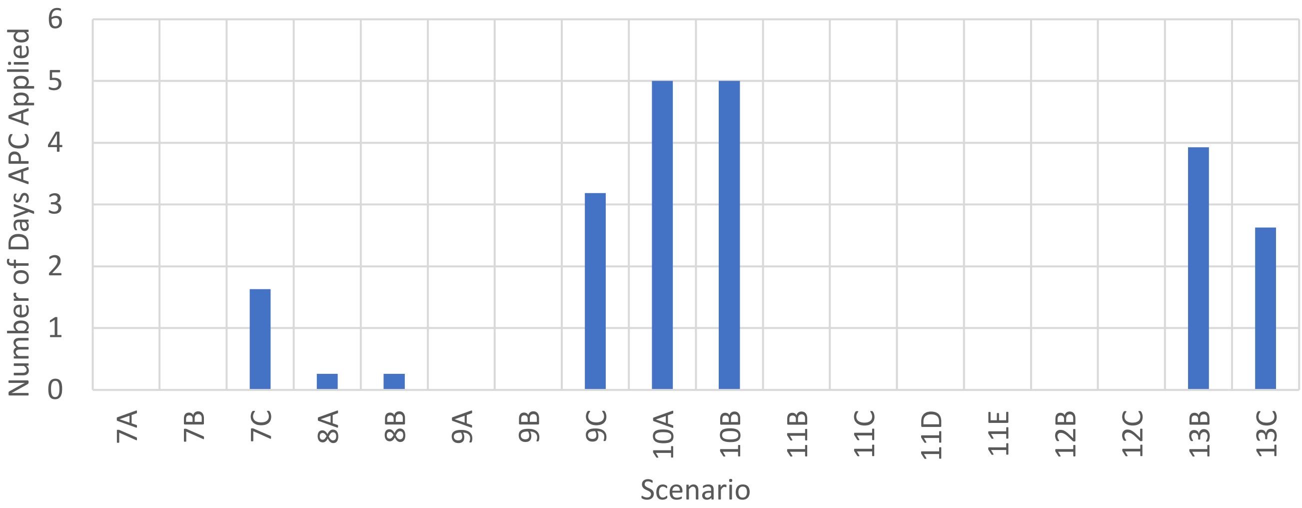


Figure 14 - Number of days for which the APC is applied (STTM)



In the DWGM, all scenarios resulted in the APC being applied for at least some grid points, and for up to approximately 13 days. However, a number of scenarios in the STTM did not result in conditions extreme enough for prices to reach VoLL/MPC or to breach CPT.

Scenarios 8 and 9 illustrate the impact of heightened demand from gas powered generators (GPG), either within the DWGM or STTM hub or backhauling from an STTM hub. To ensure that GPG behaviour was reasonably realistic we used historic NEM prices, along with operational data and heat rates to form demand curves for gas. The operation of these generators did increase prices but only to the levels that was economic for the generators.

A daily average NEM price of around $600/MWh corresponds to a maximum value of gas of between $40/GJ and $60/GJ for most GPGs. If gas prices go above these levels, then the level of GPG generation reduced. While prices in the NEM can go much higher, they would normally do so for much shorter durations requiring lower volumes of gas and hence having less impact on the gas market outcomes. In these scenarios, the behaviour of the GPGs prevented the gas prices spiking and while gas prices were increased, they were not sufficient to breach CPT.

Note that in some cases the administered price cap is applied, but does not affect the price, because the supply situation has returned to a point at which the market is naturally clearing below the APC. This is more likely to occur with higher values of APC.

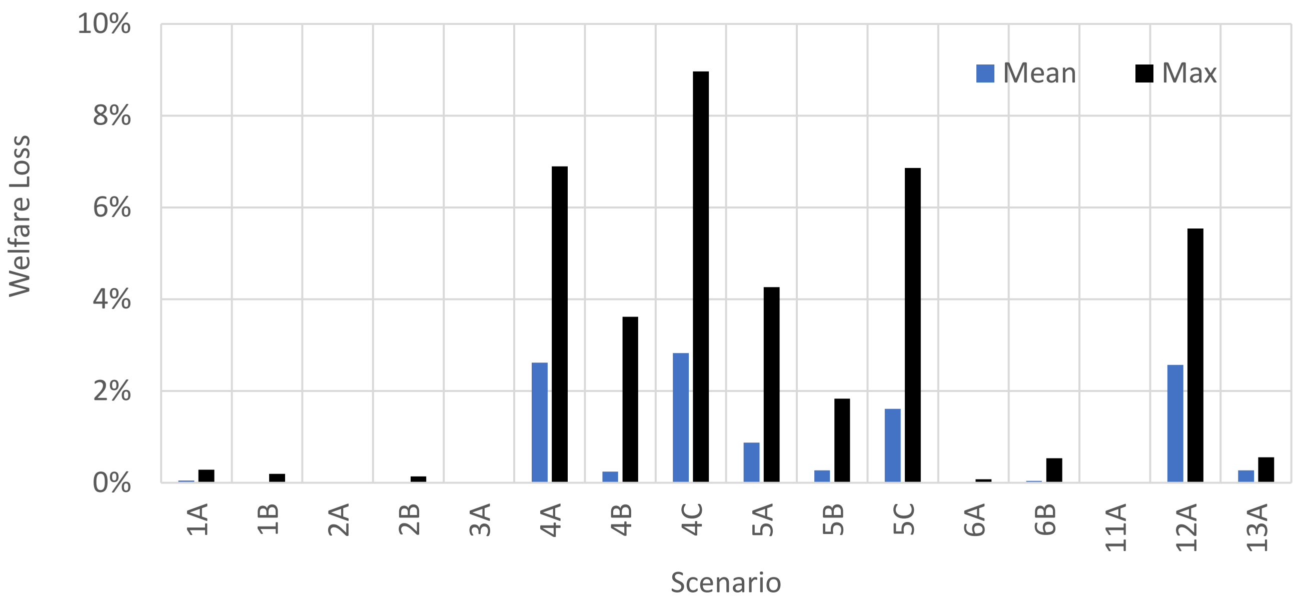
When the APC is applied, lower prices may restrict supply and lower overall level of quantity supplied.

The extent of the reduction depends on the quantity of offers above the APC and whether participants withdraw supply. Suppliers may be compensated for costs above the level of APC but for a number of reasons they may wish to truncate their offers at prices above APC. Separate cases in which supply offers above the applied APC are and are not withdrawn were run, with the former used to determine the economic efficiency loss associated with a particular combination of MPC/VoLL, CPT and APC.

The market efficiency loss is defined as the lost consumer surplus as a result of implementing the gas market parameters. Where the amount of gas cleared by the market does not change, there is no efficiency loss. Instead, there may be a wealth transfer between supply and demand participants where prices have changed. If supply is truncated above APC then some demand bids that were previously accepted will no longer be supplied.

Figure 15 shows the average and maximum efficiency losses in each scenario in which the total quantity cleared by the market is reduced.

Figure 15 - Average and maximum efficiency loss for DWGM scenarios



The level of efficiency loss incurred depends on the level of reduction in the quantity cleared. For example, these reductions may represent the loss of consumer surplus associated with uncleared bids for GPG units, and reduced exports. Depending on the market context there may be significant variation in the quantity of bids affected, and this drives the large variation in the expected losses under each scenario. Efficiency losses are therefore not solely a function of event severity.

STTM efficiency losses are not shown, as there was almost no reduction in total quantity cleared, except with the tightest of possible parameter settings. In the STTM scenarios developed, it was difficult to breach the CPT, and then sustain the market price at levels above the level of APC in the following period. Even then, to have participants exit requires supply side offers above the APC, which was not generally the case as some form of supply side offer truncation was usually the motivating intervention.

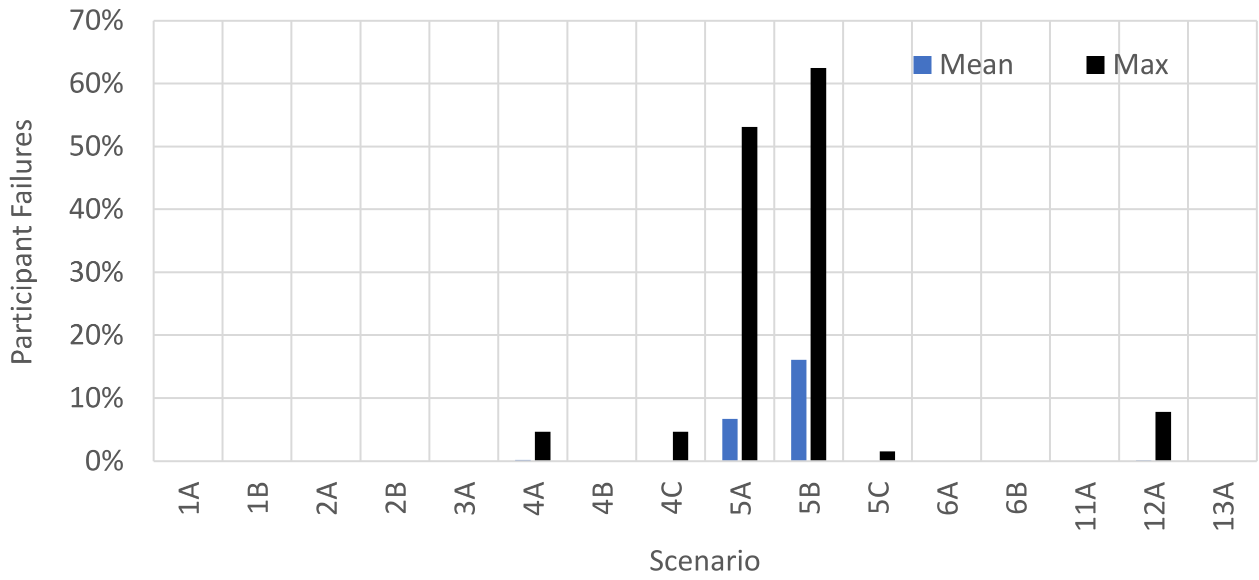
7.2.2 Participant results

While reducing market efficiency, the application of administered pricing reduces the risk exposure of consumers, which we measure by the risk exceedance percentage. We define Risk Exceedance as the proportion of case/participant combinations within a scenario with exposure to greater than 500 days of gross operating profit.

Gross operating profit and the level of hedging that a participant engages in are significant factors in the participants exposure to risk during an event. While we have simulated results for a plausible range of gross margins surrounding industry standards, where a participant operates at much lower level than the range of industry standards simulated, then that participant will not be covered by the recommended parameters. Similarly, where a participant is not adequately hedged, and is beyond the bounds of the modelled participants, they will also not be covered, and it is not the role of the market, at the cost of efficiency, to cover participants who do not exhibit responsible levels of risk management.

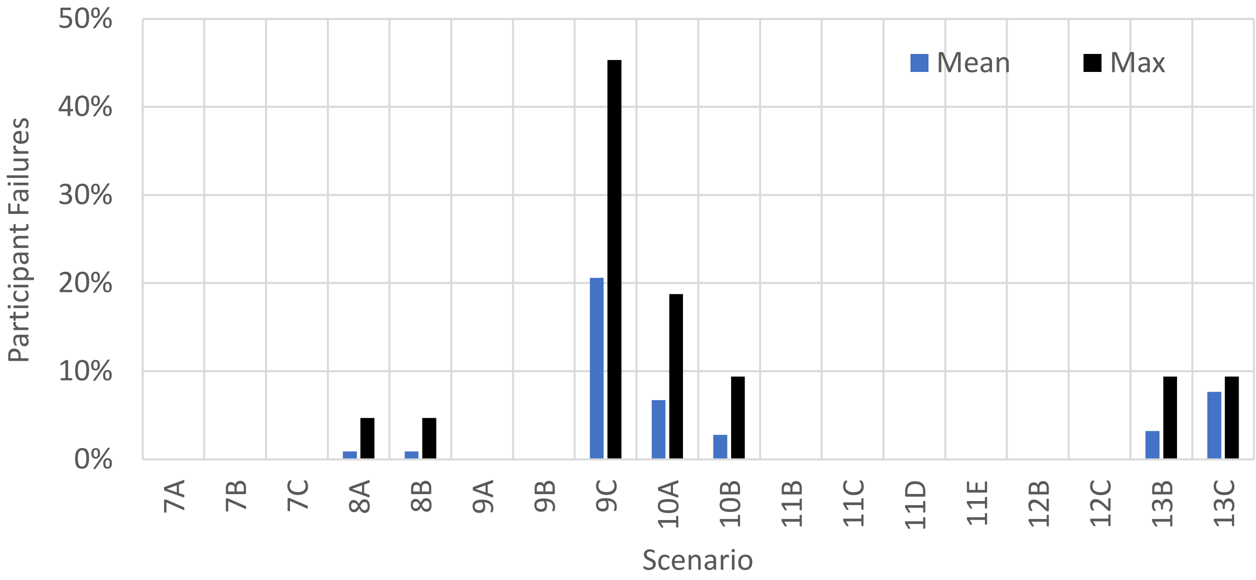
Figure 16 (DWGM) and Figure 17 (STTM) show the average and maximum level of risk exceedance by scenario.

Figure 16 - Average and maximum risk exceedance events (DWGM)



In the DWGM, the most severe risk occurs for scenarios 5A and 5B, in which there is extremely high gas demand (1-in-20 year) due to cold weather. This is likely to result in additional risk compared to supply-driven events, as the high demand may exceed the level of hedging undertaken by certain types of participants.

Figure 17 - Average and maximum risk exceedance events (STTM)



In most STTM scenarios, there are no participant failures, and most failures occur in scenario 9C, and in 10A and 10B (see Figure 17).

The proportion of participant failures in each market is strongly linked with the level of the market price cap and the type of participant being considered, as shown in Figure 18 and Figure 19. Each example of risk exceedance relates to a gas market parameter set. Sets that give rise to material risk exceedance are not appropriate settings for the market to adopt as they indicate excessive risk to participants in one or more cases. For the STTM, in particular, the only grid points in which there are no participant failures are those with a market price cap of $400/GJ, and a CPT of $440 (in which case there are no failures regardless of the value of the APC).

Figure 18 - Average participant failures at each level of VoLL (DWGM)

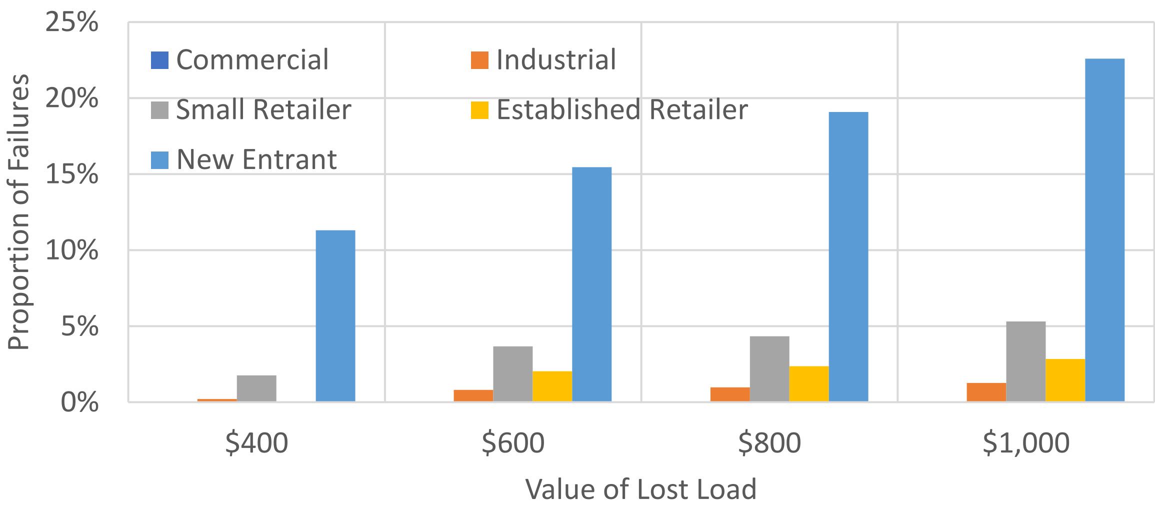
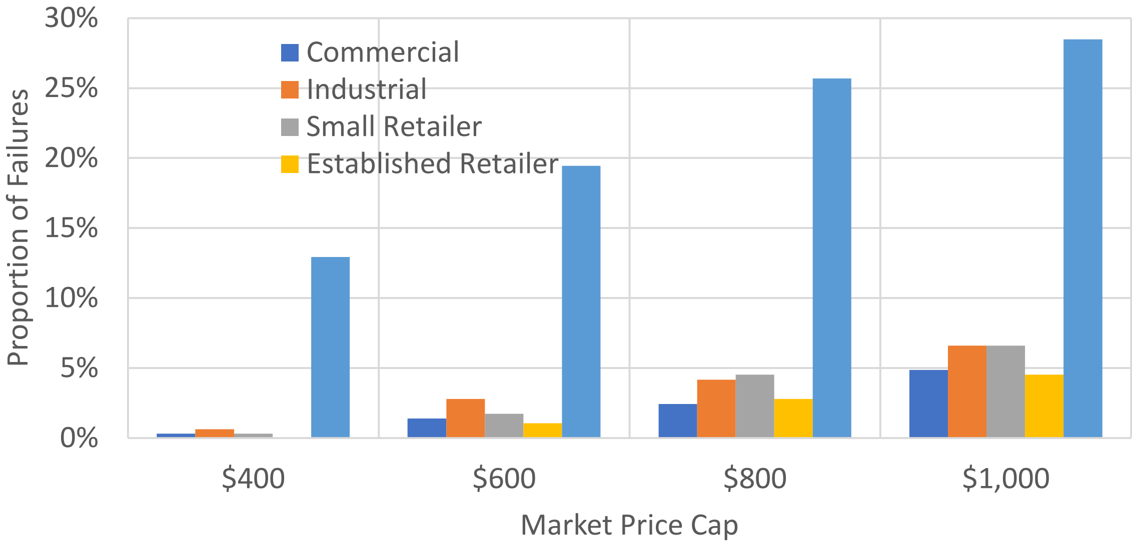


Figure 19 - Average participant failures at each level of MPC (STTM)



Relative to the last study, we have included some additional participants to provide some context of the near term. These participants are characterised as having low basic profitability so that a loss generates a significant number of days lost profit (>1000 in some cases). We do not believe these participants exist in an equilibrium state of the market (either conditions subside, or they will exit) and they are therefore not included in the parameter determination.

7.2.3 Market results

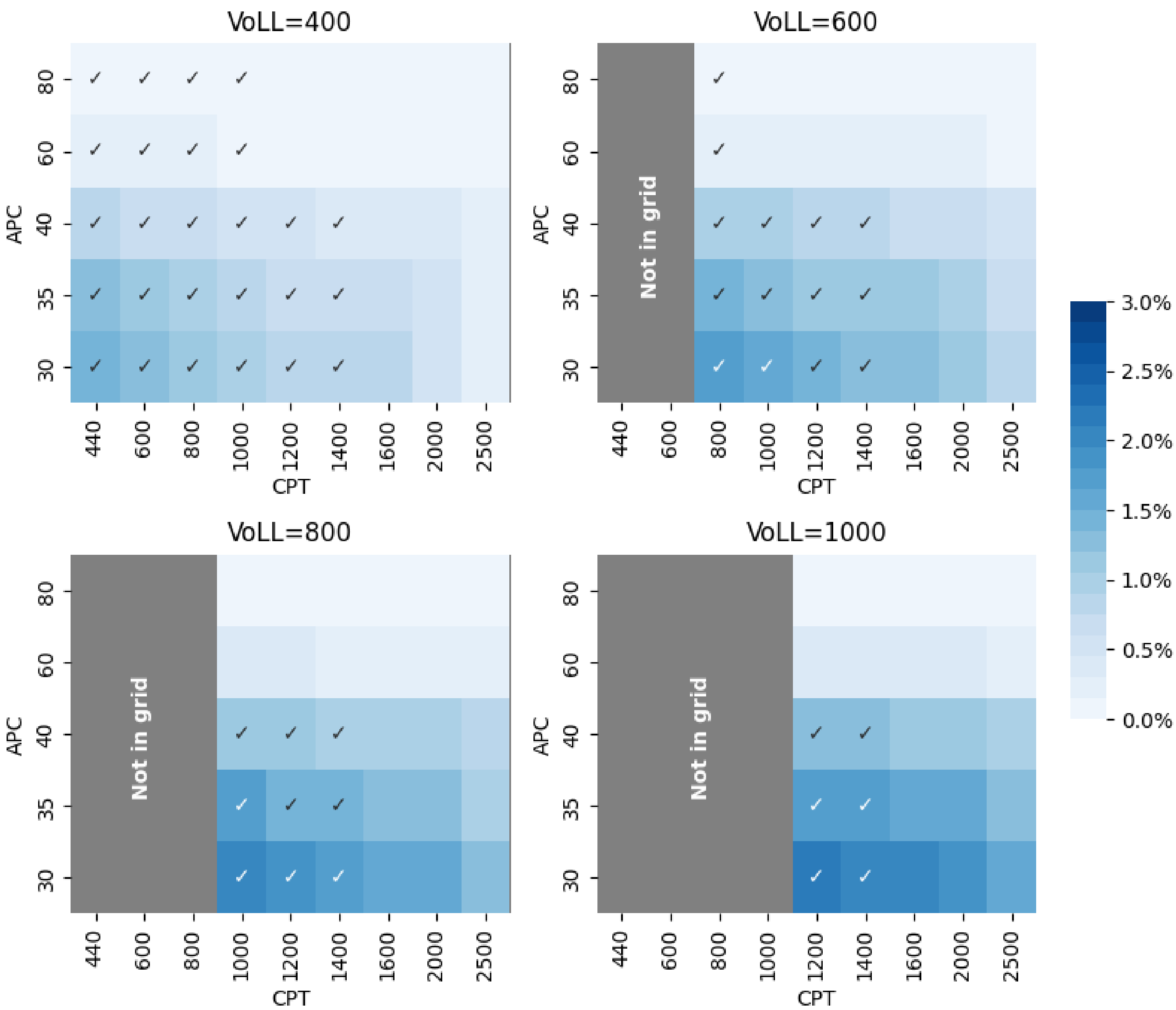
In this section scenario results from the STTM and DWGM are used to identify gas market parameter sets for each market that are acceptable throughout the study period. For each market this involves the following steps:

- Calculate the exposure for each hypothetical participant in each scenario in terms of days lost profit,
- Remove from the sample the performance of new entrants in the current market context, then
- Determine the parameter sets for each market that are compatible with the maximum 500 day lost operating profit criteria.

DWGM results

Figure 20 shows the percent decrease in efficiency, being the change in the sum of consumer and producer surplus, for those points on the grid that were tested. Regions with CPT less than VoLL were not tested. In Figure 20, each band represents an additional 0.5% increase in expected efficiency losses relative to the performance of the parameter set with no CPT applied for the DWGM. Darker shades represent higher market efficiency.

Figure 20 - DWGM % decrease in efficiency due to application of APC at various parameter combinations



The ticked regions represents the parameter combinations that are acceptable from the perspective of participant risk based on the parameter grid used. Note the actual efficiency loss recorded in each scenario varies significantly.

For a given market price cap (i.e. VoLL) it is clear that a higher CPT and/or APC will increase market efficiency while a lower value will decrease market efficiency. As VoLL increases, market efficiency can actually decrease for a given level of CPT/APC. With a fixed CPT, increasing VoLL increases the likelihood of the CPT being breached with the subsequent imposition of APC causing efficiency losses.

Based on the parameter grid, the efficiency maximising setting for each value of VoLL in 2019 involves CPT = $1000/GJ and APC = $40/GJ. An increase in the APC to $60/GJ would require a decrease in the CPT to $600/GJ, a level that would be non-sensical with a VoLL of $600/GJ or $800/GJ, and in any case would not be as efficient.

Table 8 extends the analysis and assesses the gas market parameter combinations for which no remaining participant is exposed to greater than 500 days lost operating profit in any of the scenarios contemplated by the simulation against wider criteria.

Table 8 – Acceptable DWGM Gas Market Parameters

DWGM GAS MARKET PARAMETERS					
VOLL ($/GJ)	CPT ($)	APC ($/GJ)	SUPPORTS INVESTMENT?	SUPPORTS EXTERNAL MARKETS?	SUPPORTS EFFICIENCY?
400	440	ALL	No	-	-
400	600	ALL	No	-	-
400	800	ALL	No	-	-
400	1000	ALL	No	-	-
400	1200	<= $40	No	-	-
400	1400	<= $40	No	-	-
600	1000	<= $40	No	-	-
600	1200	<= $40	No	-	-
600	1400	<= $40	No	-	-
800	1000	<= $40	No	-	-
800	1200	<= $40	No	-	-
800	1400	<= $40	Yes	<= $40	>= $40
1000	1200	<= $40	No	-	-
1000	1400	<= $40	Yes	<= $40	>= $40

While there are a number of risk appropriate parameter sets, many are not acceptable from the perspective of investment or external market interactions. The investment column defines the combinations that are acceptable for investment, while the external market column records whether or not the parameter set could be consistent with external markets. In particular, a value of APC exceeding $40/GJ would be problematic given the NEM APC settings. The last column records the most efficient setting given the remaining flexibility.

The current parameter set is still acceptable, and reasonably close to the boundary of acceptability.

Setting VoLL as high as possible does not necessarily improve market efficiency. While it does provide the market the maximum opportunity to clear, if VoLL is too high relative to CPT, then an event may result in an immediate administered price period, with the effect that the underlying cost recovery requirement of at least one VoLL period per CPT event would be lost. This possibility is more likely in situations where general gas prices are elevated, such as during winter 2022. We also note that while VoLL could potentially be increased to $1000/GJ and avoid that possibility, there are not likely to be price sensitive bids beyond $800/GJ and we are mindful that recent experiences may not bound the market behaviour in the future. Decreasing VoLL creates risks that opportunities for the market to clear will be restricted.

Variation of APC provides modest same direction increases in risk to participants. The primary consideration here is ensuring consistency with respect to the NEM APC so that it remains economic for GPG to acquire and use gas in the event both markets are in an administered state. Consistency with the NEM requires no increase in APC.

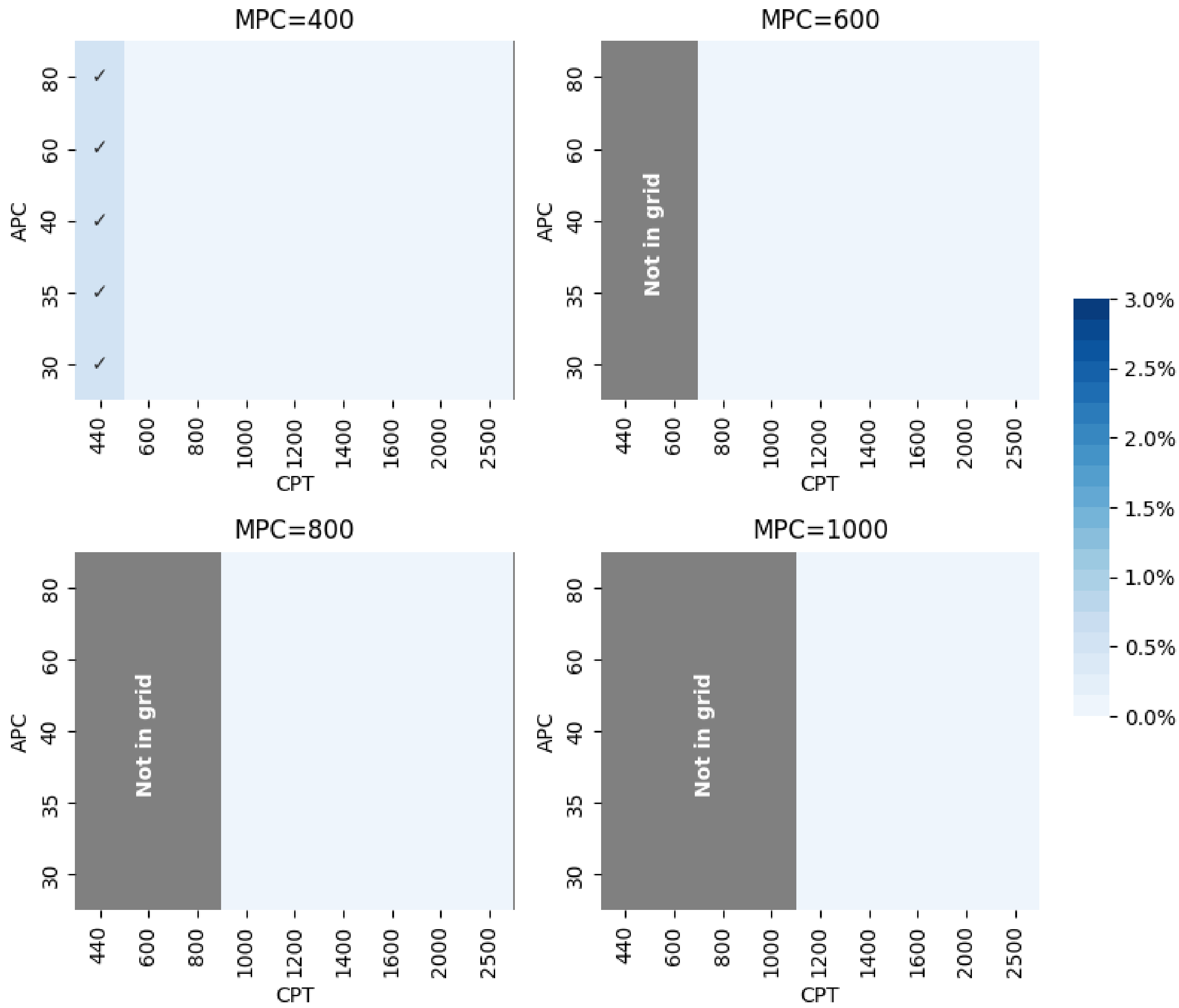
Generally higher prices create an expectation that the CPT threshold should increase, however given the other parameters, particularly VoLL, there is no evidence that this is required. In this particular case an increase in CPT to $1600 would not be tenable given the limits of participant risk. Decreases in CPT risk the likelihood of a single VoLL period arising before the threshold is crossed.

Decreases in APC are possible but provide little benefit to participants in terms of reduced risk but reduce market efficiency. Further, a decrease in APC increases the risk that a temporarily high base commodity price is in excess of APC , which would be disruptive and undesirable.

STTM results

This section reports on the STTM results. Figure 21 shows the percent decrease in the sum of consumer and producer surplus for those points on the grid that were tested. Regions with CPT less than MCP were not tested. The chosen STTM scenarios do not exhibit significant efficiency losses, except in the case where MPC = $400/GJ, and CPT = $440, in which case the efficiency loss is in the range of 0.48% – 0.57%. As shown in Figure 21 the number of suitable parameters sets is significantly reduced in the STTM relative to the DWGM. Notably, there are none other than those involving MPC=$400/GJ and CPT=$440, although in that instance there is freedom for the APC to vary, if only in terms of participant risk management.

Figure 21 - STTM % decrease in efficiency due to application of APC at various parameter combinations



While the STTM scenarios did not provide as much graduation of effect as the DWGM due to the resolution of the grid, market efficiency will be an increasing function of CPT and APC.[59] We did not consider a lower MPC in the study, and the next highest on is almost 40% higher, providing significantly more exposure in a price cap event. The CPT level has always been close to MPC due to the reduced opportunities to trade in the STTM relative to the

[59] In addition, the range of parameters over which the main decline in efficiency happens is greater for the DWGM than the STTM. The level of efficiency decrease, as described in Section 4.2, reflects reduced volumes of price responsive demand clearing (priced at less than the price cap) as the allowed clearing price declines and price responsive supply withdraws from the market. The DWGM bid and offer curves exhibit gradual changes in price over a great quantity range than is the case in the STTM. Away from the point where the market typically clears, the demand curves in the STTM are closer to vertical than those in the DWGM, and the STTM supply curves are closer to horizontal than those in the DWGM. This means that parameters need to be more restrictive for the STTM to show significant decreases in efficiency than is the case for the DWGM.

DWGM and exposure will be quite sensitive to it. The current values were established at the commencement of the STTM via an entirely separate method.

Table 9 confirms the STTM parameter combinations for which no participant is exposed to greater than 500 days lost operating profit in any of the scenarios contemplated by the simulation.

Table 9 – Acceptable STTM Gas Market Parameters

STTM GAS MARKET PARAMETERS					
MPC ($/GJ)	CPT ($)	APC ($/GJ)	SUPPORTS INVESTMENT?	SUPPORTS EXTERNAL MARKETS?	SUPPORTS EFFICIENCY?
400	440	ALL	Yes	<= $40	>= $40

Based on participant risk , the choice of available parameter sets in the STTM is far smaller than the DWGM. The only acceptable values of MPC and CPT within our grid options are MPC=$400 and CPT=$440. In combination the requirement for consistency with the NEM and DWGM, along with maximising efficiency lead to an APC parameter choice of $40.

7.2.4 Sensitivity testing of Gas Market Parameter results

Sensitivity tests were conducted for all scenarios using a tool to determine market clearances with a ±3% variation in supply or a ±1% variation in demand. These changes mean that the conditions of a scenario are slightly changed, giving rising to different pricing outcomes, different efficiency outcomes and different levels of days of lost profit. The aim was to verify the robustness of our findings for these slightly altered scenarios relative to the original scenario.

In one scenario, a 3% increase in supply would have implied MPC was not reached and the market clearing price would have been significantly lower. This would have created a large reduction in days lost profit for that scenario. In the other scenarios, the changes amount to minor adjustments as we would expect from the size of variation under consideration. Collectively, the sensitivity analysis would not result in reassessment of the market parameter set.

7.2.5 Sensitivity Testing of Lost Profit Standard

Sensitivity tests were carried out to examine the robustness of optimal parameter sets to the choice of the lost profit standard.

Table 10 describes the recommended parameter set for each level of the days lost profit standard. While the table implies a step jump in VoLL at 700 days we can only recommend a value based on the grid points modelled, and a different resolution of grid points focused on that situation might give rise to different outcomes.

Table 10 - Sensitivity of parameters to days lost profit

DAYS LOST PROFIT SENSITIVITY		
DAYS LOST PROFIT	DWGM (VOLL/CPT/APC)	STTM (MPC/CPT/APC)
300	800/1400/40	400/440/40

DAYS LOST PROFIT SENSITIVITY		
DAYS LOST PROFIT	DWGM (VOLL/CPT/APC)	STTM (MPC/CPT/APC)
400	800/1400/40	400/440/40
500 (Current standard)	800/1400/40	400/440/40
600	800/1400/40	400/600/40
700	1000/2000/40	400/600/40

In both the DWGM and STTM, lowering the lost days profit standard could not be accommodated while simultaneously protecting investment incentives. In these cases the current parameter sets would be recommended as these would be closest to restricting participant risk to the desired level.

Were higher levels to be considered, in the DWGM there is some tolerance for increasing both VoLL and CPT if the standard was increased to 700 days. In the STTM, this change would create the possibility to consider higher CPT levels.

Overall, the parameter sets chosen are robust to the risk management standard.

7.3 Assessment of implications for investment

The current parameter set supports investment. A Port Kembla type facility is, on equivalent assumptions, more economic than the Dandenong storage type facility used in the last study. Both facilities are generally supported by the existing parameter set, although both sets of analysis are quite responsive to the assumed event frequency and the assumed portion of the cost structure associated with "peak" capacity. Out of 15 sensitivities, a Dandenong type facility is investable in 13, while a Port Kembla type facility is investable in 14. On that basis, we believe the current parameter set supports investment.

Table 11 presents an example of the profit required to support a Port Kembla type facility based on a 1 in 10 year frequency. This is a basic scenario with no adverse sensitivities under consideration. This example assumes incremental capacity is available at the average cost of the project, which is not always the case.

Table 11 – LNG receipt plant investment cost calculation example

INPUT	VALUE
Capital Cost per Tonne of storage	$4,087
Peak Cost Recovery	50%
WACC	4.72%
Lifetime adjusted for zero salvage/alternate use	25 years
Annualised Cost per Tonne	$140.95
Event Frequency	0.1
Profit required ($/tonne of storage/event)	$1410

Note that the profit required is specified per tonne of storage. Our analysis considers daily injection limits as well as the fraction of injection capacity that could reasonably be absorbed by a market under such circumstances. A potential typical scenario for cost recovery during an event is shown in Table 12.

Table 12 – LNG receipt plant investment cost recovery calculation

INPUT	VALUE
Capacity adjusted daily injection limit	9.38%
Maximum hourly injection/tonne of storage (GJ)	0.213
Average VoLL hours/event	12.9 hours
VoLL income/tonne of storage at current settings	$2166
APC income/tonne of storage at current settings	$219
Total income/tonne of storage/event	$2504

The above example demonstrates the current parameter set can provide sufficient cost recovery. This is true over a number of different sensitivities and should be expected given various projects are under consideration or construction. Alternative market parameter sets are not necessarily as robust due to, the underlying calculation featuring a number of other assumptions and reflecting the complexity of estimating the cost recovery proposition. These include:

- Investment parameters such as costs and the underlying determinants of WACC
- Asset parameters such as storage limits, dispatch limits, asset life span
- Event related parameters such as average prices, event frequency, event timing, storage at time of event, lead in pricing, gas market parameters and margins.

As the parameters limit scope for cost recovery during an event, the number of sensitivities that fail to meet the standard will increase.

We also note that the sensitivities all consider the gas market parameters working in the current fashion. For any investment project, the horizon necessarily requires investors to consider potential market interventions or structural changes that would impact their ability to recover costs and/or impacts the frequency of events. Due to their uncertain nature, we have not included such considerations in our sensitivity analysis.

For all of these reasons, caution should be exercised in drawing finely tuned conclusions regarding the suitability of parameters for investment cost recovery.

7.4 Inter-market linkages

A requirement of this study was to recognise the interactions between the STTM, DWGM and NEM. This was achieved through exploring a number of scenarios that allowed interaction between the DWGM and the STTM gas hubs, while also representing drives in the NEM. As such the results of our core analysis factor in the results of those interactions.

There are practical limitations between the interactions of the gas markets. They are less able to interact in timeframes shorter than that in which gas can be moved, so most interactions will be with respect to sourcing gas during longer term events. The situation is similar between the gas markets and the NEM. While the NEM prices can respond suddenly the ability to source gas to meet that demand in the timeframe of the NEM is very limited. This is why our scenarios focused on longer term events. It was found that price responsiveness between gas and electricity markets would tend to moderate the impact of GPGs. If they drive up gas demand then gas prices rise and without a corresponding increase in electricity prices will limit the running of the GPGs.

The level of APC in gas markets is an important consideration for GPGs. The relationship between the NEM and gas markets is driven to a large degree by the price differential between gas and electricity relative to the heat rate of a GPG, though with the limitation that electricity prices and schedules change in real-time while scheduling gas can take many hours. This means the GPGs tend to be scheduled based on expectations of average prices over time in the NEM. The current $40/GJ APC, adjusted by generator heat rate, would correspond to an average daily NEM price of $400/MWh to $600/MWh. The NEM APC will be $600/MWh during the study period until mid-2025 and $500/MWh beyond that, which are consistent with the current gas APC value. While a lower APC would increase generator profitability if they could secure gas, it may also mean that gas is not made available. A higher APC of $60/GJ would reduce this risk but would increase the exposure of other market participants buying in the gas market and may recreate the conditions of Winter 2022 where the NEM APC value is not high enough to allow GPG to offset their gas costs.

There has been a view expressed from a range of stakeholders that there would be benefit in alignment of parameters between the STTM and the DWGM. Our understanding is that this view reflects concerns about the impact on trade between two markets when one is subject to administered pricing and the other is not. Our view is that the issue is more complicated than just having common parameters, as even this does not guarantee that markets will be administered at the same time. Consider the following example:

- An event that impacts the southern gas markets becomes known at 8 PM on Monday.
- The event could be reflected in the final schedule for the DGWM for the gas day beginning on Monday, and could potentially trigger administered pricing. The event could also be reflected from the 6 AM DWGM run on Tuesday, which might cause administered pricing if this was not triggered on Monday.
- In the STTM, the primary market for trading of gas for Tuesday was run before 12.30 PM on Monday afternoon, so does not reflect the event. A prerequisite for prices alone to trigger an administered state on Tuesday is if contingency gas is called, which is very rare. The contingency gas price is reflected in the cumulative price calculation and if high enough may trigger the CPT, resulting in administered pricing.

While administered pricing may eventually apply to both markets, aligning parameters alone is not guaranteed to make this happen at the same time. Further the different nature of the markets mean that the risk exposure of participants facing a common set of parameters could be quite different between the STTM and DWGM – which is why parameters are different today. Section 7.2.3 demonstrates that there is no intersection between the sets of acceptable parameters for the DWGM and STTM.

A better approach, which directly addresses the core issue, might be to maintain differences in the parameters (other than APC) but to introduce a common trigger that can immediately place two or more of the DWGM and the STTM markets in an administered state. This would require a rule change that spans both the DWGM and the STTM and the specifics of the trigger could be reasonably complicated. In particular:

- The trigger would need to be defined in terms of an event that restricts supply to two or more markets where appropriates flows between those markets will be important to managing the event.
- The specific markets impacted would need to be identified. There is no logic in involving a market that is not impacted. For instance, an event impacting the southern markets may have no impact on the Brisbane STTM hub.
- Care must be taken to ensure that administering multiple markets will not have any unintended detrimental effect. There may be situations where a lack of price difference between markets discourage flows between them.

7.5 Commentary on current gas price levels

As noted in Section 2.6.5. the underlying assumption of this analysis is that the market is in equilibrium, such that supply and demand is aligned with the prevailing typical level of gas prices. For this reason our analysis used GSOO supply and demand data and corresponding price forecasts. These price forecasts are less than current levels of gas price.

Current levels of gas price are primarily driven by the Ukraine war. This may be resolved in six months. Equally, there could other be other events in the future, such as an economic downturn, that reduce gas prices. The best read on a potential future equilibrium is probably recent history prior to covid, and the GSOO price forecasts seem broadly consistent with that.

Put simply, determining Gas Market Parameters over the long term based on prices that may reflect transient effects can be very problematic. The market is not in equilibrium during transient events meaning that participants may be inadequately contracted and gas supply and demand will differ from GSOO forecasts.

In the following discuss we comment on the implications of our recommendations in the context of the current supply and demand situation.

Case 1 – Sustained high gas prices with the market equilibrated

Suppose that prices were to remain at $20/GJ permanently such that the market re-equilibrated to the new prices.[60]

Contract prices would rise to reflect the spot price change and to preserve the current contract margin. With the proposed set of Gas Market Parameters key impacts would be:

- Lower participant risk in terms of days profit lost due to tighter CPT limits relative to price levels. CPT would be triggered more often and more quickly, limiting the effect of events when they happen. If we assume that the profit per GJ would be about double the current level, the impact would be to halve the level of participant risk.

[60] Normally, higher enduring prices would encourage an expansion of supply and a reduction in demand, such that prices would tend to decline over time.

- Investment would be less tenable. An average price of $20/GJ would mean that the normal value of the DWGM cumulative price over 35 periods would be $700, so a price rise of $500/GJ, less than VoLL, would trigger CPT. For the STTM the cumulative price over seven days would be $140, so a price rise of $300/GJ, less than MCP would trigger CPT.
- Efficiency would be relatively worse as more transactions would be curbed.

In this case we would require a CPT increase to maintain levels of investment. The DWGM might require a CPT of $1600 while the STTM requires a CPT of $600/GJ. The profit per event would still be limited for investors. There is reasonable scope to go higher with CPT if participant risk is roughly halved. The degree to which that could be pushed would depend on APC movement as well, and the NEM APC would need to be revised accordingly.

Case 2 – Transitional high gas prices without the market equilibrated

Suppose that prices were to sustain levels of $20/GJ only temporarily, before reverting to the levels predicted in the GSOO.

Under this scenario, while prices are at $20/GJ, participants are likely to face days of lost profit even without a CPT event. This means that they will have less tolerance to CPT events. For example a participant that can absorb 500 days of lost profit for an event may also be faced with 100 more days of lost profit because of base prices being high. It follows that the risk of participant failures are higher.

Importantly though, there is no parameter set that will protect fundamentally unprofitable/low profitability businesses while supporting investment. The process of re-equilibrating to new market conditions would suggest that some participants would exit the market.

7.6 Early implementation of change

Part of the scope of this review was to consider the potential to implement parameter changes earlier than this as allowed by NGR492(3), and in addition to advise on the need for earlier change from 2023.

While we are not proposing to change parameters, we do suggest that if a measure is adopted to align triggering of administered states across multiple markets then that should be adopted as early as possible. The justification is that problems were identified in Winter 2022 and as we identify in this report, aligning gas market parameters alone will not achieve that.

7.7 Conclusions

For a parameter set to be acceptable it must:

- Control unmanageable participant risks;
- Provide sufficient opportunity for investment cost recovery;
- Be consistent with similar arrangement in linked markets, such as the NEM; and,
- From the range of acceptable parameter sets, it should be efficient, as measured by maximising total market surplus

In the DWGM, our analysis reveals a significant number of sets of parameters that satisfy the first requirement, the management of participant risk. Those combinations with low CPT and/or high VoLL/CPT ratios fail to meet the standard for investment. In the first instance this is because the absolute level of cost recovery is limited, while in the second case, the APC triggering condition serve to minimise the number of periods VoLL pricing is available to investors.

Considering the current parameter set of VoLL=$800/GJ, CPT=$1400, and APC=$40/GJ:

- Most of the remaining options have flexibility in terms of APC, except that APC>$40/GJ is problematic and likely to be inconsistent with NEM administered price, given typical heat rates for gas turbines. It is also the case that decreasing APC results in welfare losses as it increases the likelihood that price controls prevent transactions that otherwise would occur, while providing no additional risk management benefit at the margin. Therefore, it is our recommendation that the APC should not change.
- Decreasing the CPT in conjunction with VoLL would risk investment cost recovery. Decreasing the CPT while retaining VoLL or raising it would reduce VoLL pricing opportunities and a have similar effect on investment incentives. Increasing the CPT is also not possible without subjecting participants to excessive unmanageable risk. Therefore, it is our recommendation that the CPT should not change.
- There is scope to increase VoLL to $1000. This change has a mixed effect on participant risk and investment incentives. Given the impact on both participants and investors is minimal and the benefits may depend on the future market context, our recommendation is to maintain the current VoLL.

In the STTM, the current parameter set is MPC=$400/GJ, CPT=$440, APC=$40/GJ. The STTM has significantly fewer degrees of freedom compared to the DWGM. The only parameter sets acceptable to participants from a risk management perspective involve MPC=$400/GJ, CPT=$440, with APC free from a risk perspective. It should be noted that the difference in the timing of the imposition of the APC allows for much lower CPT/MPC ratios and that the current value of CPT in each market continues to lie within the range for which one MPC/VoLL will arise per CPT event in both the DWGM and STTM. Regarding APC, the same argument above applies; the APC cannot be raised without creating conflict between markets such as the NEM and it is preferable that it align with the same value in the DWGM. Further, it should also not be lowered as it will inevitably reduce market efficiency. Therefore, our recommendation is to also maintain the current gas market parameters in the STTM

Notwithstanding the above analysis, comments received from a range of stakeholders in this review favoured alignment of parameters between the STTM and the DWGM in an effort to avoid one market being in an administered state earlier than another, creating distortions in flow between them.

While the goal of this change is appropriate, we consider that a more appropriate approach is to establish a trigger mechanism that can simultaneously trigger administered states across two or more of these markets. This would have the desired effect. A common set of Gas Market Parameters across all markets would create significantly different exposures for participants in STTM hubs than for those in the DWGM due to the fundamental differences in the design of these markets, and in particular the much long lead times between trade and delivery that exist in the STTM relative to the DWGM.

From the perspective of participant risk, the only parameter setting that would protect participants in both markets would be MPC=$400/GJ, CPT=$440, and APC=$40/GJ. This setting would remove the possibility of pricing attaining VoLL levels, thereby making investment cost recovery infeasible. Further relaxation of the CPT to support investment cannot be entertained in the STTM without increasing participant risk to unacceptable levels. Therefore there is no parameter set that would be acceptable in both markets. Separate parameter sets are required for each market.

8 CONSULTATION

8.1 Topics raised and our response

8.1.1 View on the no change to Gas Market Parameters

Only five responses were received with Energy Australia and Australian Energy Council being broadly supportive of no change. The other responses did not explicitly comment on the position of no change. All responses did make comment on potential changes that could be made in the review methodology or process going forward.

8.1.2 Alignment of NEM, STTM and DWGM parameter review processes

The AER and Energy Australia expressed support for alignment of the review process between the NEM, STTM and DWGM. The respective rules make the NEM parameters review a task for the Reliability Panel, with AEMO having the corresponding role for the STTM and DWGM. In each case the reviews feed in to an AEMC rule change process. Market Reform has already taken the position that alignment would be logical, whether through a single review, or a process of aligning the reviews to be concurrent and interacting (even if run by different bodies). While rule changes give greater certainty to the market, we note that even without any rule changes it would be possible for them to be scheduled concurrently with interaction between them.

If such a change were to be adopted, we would suggest that some thought be put into the nature of the interaction and extent of methodology alignment well in advance of execution of the reviews. The different nature of the markets – the NEM, the STTM and the DWGM – and their complex interactions mean that this is not a trivial task and is unlikely to be easily resolved within the normal execution time of reviews.

8.1.3 Alignment between the STTM and DWGM

As discussed in this report the STTM and the DWGM operate under quite different market designs. Our review and indeed all prior reviews, have concluded that it is appropriate to have different Gas Market Parameters in these markets to reflect the different risk characteristics of those markets.

This section explores submissions on suggestions in our report to improve alignment as well as new proposals including in submissions. While we understand the desire to achieve greater alignment between markets, the challenge is that approaches which focus on better aligning them in one dimension – such as via Gas Market Parameters – can make them mis-aligned in another dimension – such as level of risk exposure.

8.1.3.1 Aligning market designs

Energy Australia acknowledged some of the legacy challenges in alignment of the STTM and DWGM but suggested that aligning their designs could help this. This is an interesting approach but achieving it would require either more trading opportunities in the STTM (which is limited by the ability for pipeline operators to facilitate changes in schedule during the day) or a simplification of the DWGM (which might be considered a quite regressive step and may create new operational challenges with system operation). Neither of which seem easy to do.

8.1.3.2 Acceptable Risk

Origin wanted to improve alignment by raising CPT in the DWGM. It is concerned that the DWGM is more likely to enter an administered state than the STTM.[61] Origin cites this as a key factor in the events of Winter 2022. Origin correctly note that the difference between settings in the DWGM and STTM are a function of the 500 days of lost profit threshold used in defining acceptable risk in both markets. Origin indicated it would like more consideration of appropriate acceptable risk given the existing 500 days of lost profit measure dates from 2013. We would note that in the context of the methodology currently used, an increase in CPT in the DWGM relative to the STTM may require a different number of days of lost profit in the DWGM from that in the STTM.

Energy Australia saw value in consideration of a Risk Aversion approach proposed by the Reliability Panel in the NEM. This approach focuses on planning conservatively for the risk of:

- Energy required to just achieve a 50% probability of unserved energy, weighted by a factor (e.g. 90%), plus
- The energy required to just achieve a, for example, 95% probability of unserved energy, weighted by one minus the weighting factor above (i.e. 10%).

This approach is a simplified way of defining an effective margin above the 50% scenario so as to reflect that the market values a lower risk exposure. Importantly, the NEM has a reliability standard which provides a measure of an adequate level of reliability, such as a maximum level of unserved energy, relative to which this approach can be applied. There is currently no gas reliability standard relative to which the method could be applied. Consequently there would need to be other changes in gas planning before a Risk Aversion approach could be applied.

One of the challenges of defining acceptable risk is that there is no single right answer and the attractiveness of a given approach to a stakeholder is likely to vary with their view on the appropriate trade-off between participants managing their own risk and some component of risk cost being borne by others . This is one of the considerations in staying with an established approach.

It may be appropriate in the next review to revisit these settings. In particular, climate policy may become more relevant. For example, the Step Change scenario in AEMO's forecast is based on a significant move away from gas heating and other domestic usage of gas, which implies a contraction of the market and implies fewer participants going forward. To the extent that it becomes clearer by the next review that this is the reality, at least for some markets, it will be important to consider the implications of that – e.g. the retail market may need to rationalize and that may change the risk profiles going forward.

8.1.3.3 Alternative CPT calculations

Both Shell and the Australian Energy Council suggested alternative approaches for calculating CPT in the DWGM. The aim of these approaches is to adjust the CPT calculation in the DWGM to keep the level of cumulative prices more aligned with the STTM and its single daily price.[62] While Shell provides more detail than the Australian Energy Council, the key idea is to determine a price to contributed to CPT at each schedule which is a trade

[61] As we note in our discussion in the next section, this is fundamentally a result of the DWGM having more trading opportunities than exist in the STTM.
[62] We note that the STTM CPT is not based on just the day-ahead market price, it is also dependent on contingency gas and ex post imbalance price data for prior days

volume weighted average over all DWGM prices for the day thus far.[63] Thus, simplistically, if 1% of gas is traded late in the day at a price of $800/GJ, that would only add $8/GJ to the CPT, not $800/GJ. The argument appears to be that this approach implies a lower contribution of CPT and one that is more comparable to the single (day ahead) price in the STTM.

Shell indicate that this will:

- Result in sustained high prices still triggering administered pricing;
- Prevent CPT being triggered if high prices last two periods but volumes are small; and
- Would allow the CPT in the DWGM to be lowered to be closer to the price cap.

The Australian Energy Council also conclude that this type of approach would better align the DWGM market with the STTM, and would negate the need for a new APC trigger event across markets.

In response, we conclude that these proposals are focused more on the process of triggering CPT than on the level of exposure that participants are exposed to. Consider the DWGM. It includes five schedules for a gas day and each schedule can be considered to be separate, but interlinked, market outcome for imbalances and deviations for the gas day. The cumulative price allows for price protection of both deviations and imbalances equally throughout the gas day. Given contracting, there might only be 5% or 10% of the market exposed to the price for the first schedule of the day, and while exposure will typically be less in later schedules, on a day with a surprise peak demand (with consumers buying more) or a major supply outage (with prior sellers buying back gas) the level of trade later in the day could get up to similar magnitudes. And it is at these times that protection from extreme prices becomes important. The CPT concept is based on the cumulative exposure of someone buying in any schedule, rather than the cumulative value of trade for the overall market.[64] As such, a weighted average of a number of prices that do not relate to the price at which current trading is occurring seems an odd trigger.

If, in the DWGM, there were a supply interruption or unexpectedly high peak demand later in the day the resulting higher prices could cause CPT to be exceeded triggering APC. This provides protection to those who would otherwise be exposed to those prices. The volume weighted average CPT approach would delay the imposition of the APC, increasing the number of days of exposure of exposed buyers. A Gas Market Parameters review might then reduce CPT to limit that exposure. It is unclear if the net effect would be significantly different from the current outcome or not. Ultimately the aim is to provide protection for those trading in each of the five DWGM schedules for a gas day. A derived fictional price that pretends that there is only one DWGM daily market may make the triggering process look more like the STTM's trigger, but it does not change the fact that participants can be exposed in any of the five markets.

8.1.3.4 Triggering administered states in multiple Markets

There was a range of feedback on the possibility of triggering administered states in multiple markets.

[63] Shell's submission refers to weighting prices after the first schedule by the volume of deviation. In reality the volume traded at a reschedule reflects gas required to address deviations as well as additional imbalance gas traded to reflect changes in the expected future supply and demand position.

[64] While there may be schedules where no one is exposed to a price, this is because they are hedged by contracts or earlier schedules. Precisely the same thing is possible in the NEM with energy contracts meaning no one is exposed to a price, but the price still counts towards CPT.

Origin was not supportive of introducing an additional trigger. It prefers adopting parameters that "set at an efficient level to balance participant risk while supporting market operations / investment signals, which we consider could be achieved by increasing the DWGM CPT to improve alignment with the STTM".

Energy Australia proposed giving AEMO power to both trigger additional administered states once one market is administered but with an onus to avoid this where possible and end the event as soon as possible. We note that, as with the current triggers, it is more normal to have clearly defined trigger mechanisms and clearly defined mechanisms to end states so as to avoid the appearance (or accusation) of arbitrary or inappropriate market operator action.

The Australian Energy Council commented that their alternative CPT calculation proposal, discussed above, might avoid the need for an additional trigger.

As we note above, alignment between markets on some parameters, such as the trigger, may imply non-alignment in other areas, such as risk exposure. This is a factor in our proposal for an additional trigger to specifically address the specific problem of a wide scale event impacting multiple markets.

The AER observed that a new trigger would effectively imply an over-ride of the value of CPT in the market for which it is yet to be triggered.[65] The AER suggested consideration of the workability of the recommended approach to adjust the CPT in other market(s) on an event basis and subject to criteria.

In making the suggestion for a new trigger we have been clear that the exact situation in which it is applied needs to be carefully considered, and that there would be situations where it could be counter-productive to apply it.

The need for a very prescriptive approach might imply something like the following for a trigger:

- Certain rule defined and quantifiable measures indicate that group of markets are in a more constrained supply state than usual, and
- One of those markets has entered an administered pricing state based on CPT but CPT has not been triggered in other markets in the group, and
- For one of the markets not yet administered, certain rule defined measures – such as current CPT levels, forward gas bulletin board or other information – indicates that a sustained administered state is likely in the near future.

The ending of the state may be triggered by improvements in the data that informed the triggering decision (independent of other triggers of administered states).

8.1.3.5 Other points

It was noted that some policy positions, notably the Competition and Consumer (Gas Market Emergency Price) Order 2022 and expanded AEMO powers have arisen or become clearer since our Draft Recommendation report was published. The body of this report has been updated to reflect these and to reflect why we do not believe they are material to our findings. To the extent any material consequences become apparent for future reviews then that could be reflected in those reviews.

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[65] To this we comment that there already other administered pricing triggers in both the DWGM and STTM that are unrelated to CPT, so as a new trigger it is not necessary to view it as implying a changed CPT.

8.2 Conclusions

We see no basis for revising our recommendations for the Gas Market Parameters based on the submissions. The submissions are however relevant for consideration in planning for future reviews, as well as any rule changes around alignment of reviews, new triggers that impact multiple markets.

9 RECOMMENDATIONS

Recommended Gas Market Parameters

We recommend no changes to the gas market parameters. The reasons for this are:

- The current parameters are still acceptable while still being close to the limits of what is acceptable.
- In the DWGM there are no options for adjusting CPT that both support investment and participant risk management. There is scope for increasing VoLL to $1000/GJ but it is no clear benefit to doing so.
- In the STTM, the analysis revealed no suitable alternatives for either MPC or CPT.
- We favour no change to the current APC values in both the STTM and DWGM. The AEMC's new settings of the NEM APC were based on the current gas APC values and raising the gas APC values would conflict with the NEM settings, potentially recreating some of the detrimental issues encountered in Winter 2022. While our analysis indicates lower APC values could be supported we do not propose it as it would significantly reduce market efficiency
- Preserving the current parameters minimises the impacts on current contractual arrangements.

Additional recommendations

The following recommendations may be viewed as beyond our scope but based on feedback and our own analysis and experience in conducting this review seem worthy of further consideration.

- There have been suggestions of aligning parameters between the DWGM and STTM. The goal of this would be to reduce the risk of one market being in an administered state earlier than another, creating distortions in flow between them. No single set of all three parameters was found that could be applied across both the DWGM and STTM. This result reflects the quite different market designs, including different frequencies and timeframes of scheduling. We instead recommend consideration of a new administered state trigger mechanism that would allow simultaneous administering or two or more markets from the DWGM and the three STTM supply and demand hubs. This should be in addition to the existing trigger mechanisms, and should be applied to mitigate detrimental impacts on inter-market gas flows when some markets are administered while others are not. The specific markets impacted would need to be determined as part of the event. The trigger would have to be a measure that reflects reduced supply to those markets where a rational response to the issue requires consistency of administered pricing between them.
- It would be beneficial to align the reviews of NEM paraments and the Gas Market Parameters. At minimum the reviews should be run concurrently with interactions between them. This would largely mitigate the risk of misalignment between parameters.

APPENDIX A SCENARIOS

The following table describes the scenarios modelled. For each of our scenarios we identify a Market Context being either the Progressive Change or Step Change scenario from the GSOO. The Progressive Change was our default choice, typically having higher gas demand, though the Step Change scenario is used when more fitting for the scenario. To the extent that we find that the setup of a scenario does not trigger the administered price cap we may instead use the alternative Market Context if this does trigger the administered price cap.

To avoid conflating two different issues, we have not applied the 'high electrification' context, which relates to broad demand changes arising from uptake of electric vehicles for example, to scenarios that involve short-term events in the NEM.

The years of focus span the review period – July 2025 to June 2028. The scenario years below are to be read as the 12 months beginning in June (or in practice in winter) of that year. We have specifically included some scenarios based on the years starting July 2024 in order to test the value of earlier implementation of revised market parameters as allowed by the NGR. We also have four variations of scenarios for the year from July 2023 (all shaded purple) which aim to implement the same type of situations as described in the main scenario but adjusted to be relevant for 2023. The 2023 scenarios are intended to provide informal information on the performance of parameters in 2023.

Some scenarios have been refined relative to those in our earlier consultation report. Some changes have been made to provide more clarity on the specific conditions used in the modelling. For some step change cases, the nature of the events needed to be made more extreme to offset the lower gas demand in those scenarios.

Table 13 - Scenario descriptions

SCENARIO	MARKET & YEAR	MARKET CONTEXT	EVENT	DETAIL
1A	DWGM 2024	Progressive Change	Gippsland supply interruption	A complete outage of Longford production on a 1:2 year demand day[66] with output restored during the day of the event resulting in prices rising to VoLL for two periods. NEM prices are at average winter values.
1B	DWGM 2026			
2A	DWGM 2026	Progressive Change	Compressor failure on VNI	Pipeline compressor failure on a high flow day from the north reduces supply to Melbourne. The failure occurs early on a 1:2 year demand day.[67] Output restored at midnight on the third day of the event. NEM prices are at average winter values.
2B	DWGM 2027			

[66] Demand day severity ranges from average winter demand to high winter demand which is defined as the average of the highest demand week, through to 1:2 year and 1:20 year standards. Originally this scenario was designed to occur on a high demand winter day, but this was not sufficient to trigger parameters. The severity of the demand day was upgraded to the 1:2 year standard.

[67] See prior footnote.

SCENARIO	MARKET & YEAR	MARKET CONTEXT	EVENT	DETAIL
3A	DWGM 2026	Step Change	Moomba supply interruption with a high rate of flow to SA and NSW.	High rate of gas export from DWGM to support ADL and SYD for three days after a Moomba supply interruption. Event occurs during a high winter demand period.[68] NEM prices are at high levels (circa $300/MWh) reflecting the supply interruption, but without the NEM prices being capped.
4A	DWGM 2025	Progressive Change	High Forecast GPG Demand with restricted coal availability	High expected GPG demand resulting from restricted coal availability and coincident with high winter demand. The scenario has average NEM winter prices rising to $660/MWh long enough to trigger APC in the NEM. This would produce extra high demand going into the day. Increased flow of gas to SA to manage increased GPG demand there.
4B	DWGM 2026			
4C	DWGM 2024			
5A	DWGM 2025	Step Change	Extremely high demand	Demand in excess of 1:20 year scenario – e.g. due to extremely cold weather. A cold day in excess of a 1:20 year scenario followed by two days of very cold (though not as extreme) days. NEM prices are at a high level (that could lead to APC in the NEM). This is a situation where demand may also exceed normal contract / hedge limits.
5B	DWGM 2026			
5C	DWGM 2023	Progressive Change		
6A	DWGM 2026	Step Change	High demand day requiring LNG while gas storage is low.	1:2 year demand[69] with inflated LNG prices and low gas storage levels due to high demand earlier in the winter and/or as a consequence of previous events. Demand increases unexpectedly during the first day causing LNG to be used. Demand drops back to average winter demand at end of third day. NEM prices are high encouraging GPG demand.
6B	DWGM 2027			

[68] Originally this scenario was designed to occur on an average winter demand day, but this was not sufficient to trigger parameters. The severity of the demand day was upgraded to high winter demand standard which is defined as the average of the highest demand week.

[69] Demand day severity ranges from average winter demand to high winter demand which is defined as the average of the highest demand week, through to 1:2 year and 1:20 year standards. Originally this scenario was designed to occur on a high demand winter day, but this was not sufficient to trigger parameters. The severity of the demand day was upgraded to the 1:2 year standard.

SCENARIO	MARKET & YEAR	MARKET CONTEXT	EVENT	DETAIL
7A	SYD 2026	Step Change	Reduced supply to hub due to upstream reduction in production.	MSP flow to SYD reduced by 50%[70] at time of high winter demand but known at the time that the ex-ante market ran. Flow is reduced for three days. As DWGM is also supplied from Port Kembla we assume no capacity to increase flows from the DWGM to SYD
7B	SYD 2027			
7C	SYD 2024	Step Change with Pt Kembla Delay		
8A	ADL 2025	Progressive Change	Reduced supply to hub due to high GPG demand outside of the hub during ex ante market	GPG's constrain pipelines in the ex-ante market due to purchasing high volumes of backhaul gas arising from high electricity demand. At peak GPG consumption, the SEAGas and MAP pipelines may be reduced by as much as 60%.
8B	ADL 2027			
9A	BRI 2026	Progressive Change	Reduced supply to hub due to unexpected high GPG demand outside of the hub after ex ante market has run.	GPG's buy high volume of back haul gas in ex ante market due to high electricity demand for three consecutive days during winter (though season not that important). NEM prices rise to a level that has generation near the Brisbane hub operating at maximum after the ex-ante market has run. Causes supply issues in hub on first day (e.g. contingency gas) but factored into ex ante market on subsequent days. Generation stops running on the third day.
9B	BRI 2029			
9C	BRI 2023			
10A	SYD 2024	Step Change	Contingency gas scenario	Contingency gas scenario arising from a supply interruption reducing gas supply to the hub by 50%[71] after the day ahead market has run.
10B	SYD 2026			

[70] The Technical or Operational Conditions of the STTM procedures place limits on how much supply to the STTM can be restricted before AEMO can activate an Administered Market State which would have APC applied at a 5% reduction. Originally it was proposed to limit this reduction to 5% because of this. The decrease in demand under the step change scenario combined with expanded supply options meant a more significant drop was required to produce extreme prices in some of the step change cases.
[71] See prior footnote.

SCENARIO	MARKET & YEAR	MARKET CONTEXT	EVENT	DETAIL
11A	DWGM 2026	Progressive Change	Imports to DWGM are high, increasing prices in the DWGM and SYD, ADL hubs. Interlinked markets scenarios.	Extreme winter demand in the DWGM with lower than usual local gas storage requiring higher than usual flows to the DWGM from NSW and SA, increasing prices in DWGM and the supply costs to the SYD and ADL hubs. Event is expected prior to the STTM ex-ante markets running and lasts for three days.
11B	SYD 2026			
11C	ADL 2026			
11D	ADL 2023			
11E	SYD 2023			
12A	DWGM 2026	Progressive Change	High GPG demand in or around key markets. Interlinked markets scenario	High electricity prices for a sustained period (e.g. due to outages and low VRE) require long-term running of gas-powered generation at higher utilisation than normal. This causes strong linkage between the DWGM and the ADL and SYD STTM hubs. High winter demand, with electricity prices at levels likely to trigger APC in the NEM. Starts prior to the ex-ante market bid submissions and lasts for three days. There is a high demand for DWGM exports to the STTM.
12B	ADL 2026			
12C	SYD 2026			
13A	DWGM 2026	Step Change	External events cause rapid rise in international commodity prices driving high prices in Australia coinciding with high gas demand. Interlinked markets scenario	An unanticipated increase in international prices (oil, coal, gas) drive higher gas and electricity prices in Australia as substitutes for energy production are more expensive and domestic gas supply is reduced. We assume that electricity prices are not capped in the NEM (which means more gas demand), driving high GPG gas demand. ADL has been selected ahead of BRI as ADL faces a greater impact of non-STTM GPG demand outside the hub.
13B	SYD 2026			
13C	ADL 2026			

APPENDIX B SCENARIO RESULTS SUMARY

This appendix presents high level summary results for each scenario. The following terminology is used:

- Base Scenario Average Price ($/GJ) reflects the average price in the market between the start and end of an event for the base scenario, i.e. where no event occurs. The base scenario price considers typical demand and supply stacks, including prevailing GPG demand, with stack price increases based on GSOO forecasts. These typically suggest relatively high price periods in the earlier study years with pricing becoming more relaxed towards the end of the study period.[72] We have not calibrated prices with recent pricing because the current market context cannot be assumed to persist.[73]
- Uncapped Average Price (% of VoLL) is the average gas price in the market for a case with the current VoLL/MPC values and no application of CPT between the start and end of an event when the event has occurred, expressed as a percentage of VoLL
- Average APC Active Period is the average number of periods from the commencement of the event for which the price is capped at APC.

Table 14 - Scenario output summary

SCENARIO	MARKET CONTEXT (P=PROG, S=STEP)	BASE SCENARIO AVERAGE PRICE ($/GJ)	UNCAPPED AVERAGE PRICE (% OF VOLL)	UNCAPPED MAXIMUM PRICE (% OF VOLL)	AVERAGE APC ACTIVE PERIODS
1A	DWGM 2024 P	$13.65	0.042	1.000	6.319
1B	DWGM 2026 P	$13.34	0.029	0.481	1.489
2A	DWGM 2026 P	$13.34	0.025	0.056	0.526
2B	DWGM 2027 P	$13.76	0.028	0.079	0.859
3A	DWGM 2026 S	$11.00	0.159	1.000	10.630
4A	DWGM 2025 P	$13.34	0.075	1.000	10.119
4B	DWGM 2026 P	$13.34	0.034	0.162	2.504
4C	DWGM 2024 P	$13.65	0.077	1.000	10.126
5A	DWGM 2025 S	$11.80	0.052	1.000	8.570
5B	DWGM 2026 S	$11.97	0.050	1.000	7.911
5C	DWGM 2023 P	$35.39	0.079	1.000	11.141
6A	DWGM 2026 S	$11.97	0.031	0.152	2.059

[72] For example, the base scenario prices for step change scenarios for Sydney from 2026 (7A, 7B, 1010B, 13C) are lower than for other hubs. These cases include additional supply from new facilities, primarily Port Kembla, while being less impacted by high GPG demand than other hubs, which gives rise to the lower prices.

[73] As noted in the body of this report, the expected equilibrium positions are established using the LGA gas price projections accompanying the 2022 GSOO.

SCENARIO	MARKET CONTEXT (P=PROG, S=STEP)	BASE SCENARIO AVERAGE PRICE ($/GJ)	UNCAPPED AVERAGE PRICE (% OF VOLL)	UNCAPPED MAXIMUM PRICE (% OF VOLL)	AVERAGE APC ACTIVE PERIODS
6B	DWGM 2027 S	$11.10	0.030	0.155	2.222
7A	SYD 2026 S	$9.75	0.018	0.029	0.000
7B	SYD 2027 S	$9.55	0.017	0.027	0.000
7C	SYD 2024 S	$11.09	0.101	0.856	1.630
8A	ADL 2025 P	$18.42	0.085	1.000	0.259
8B	ADL 2027 P	$17.97	0.084	1.000	0.259
9A	BRI 2026 P	$10.27	0.020	0.061	0.000
9B	BRI 2027 P	$10.37	0.019	0.063	0.000
9C	BRI 2023 P	$10.56	0.112	1.000	3.185
10A	SYD 2024 S	$11.09	0.159	1.000	5.000
10B	SYD 2026 S	$9.75	0.158	1.000	5.000
11A	DWGM 2026 P	$13.34	0.023	0.038	0.526
11B	SYD 2026 P	$11.62	0.020	0.031	0.000
11C	ADL 2026 P	$18.12	0.044	0.228	0.000
11D	ADL 2023 P	$18.42	0.038	0.140	0.000
11E	SYD 2023 P	$12.55	0.022	0.034	0.000
12A	DWGM 2026 P	$13.34	0.162	1.000	10.852
12B	ADL 2026 P	$18.12	0.048	0.219	0.000
12C	SYD 2026 P	$11.62	0.024	0.073	0.000
13A	DWGM 2026 S	$21.38	0.081	1.000	9.170
13B	SYD 2026 S	$9.75	0.130	1.000	3.926
13C	ADL 2026 S	$16.91	0.127	1.000	2.630

APPENDIX C PARTICIPANT RESULTS SUMMARY

This appendix presents high level summary results for each participant. The following terminology is used:

- Gross Margin (%) reflects the retail margin assumed for each retailer/integrated supplier and the final product margin achieved by industrial users.
- Gas Fraction of Cost (%) is the proportion of participant total costs assumed to be related to gas.
- Maximum Days Lost Profit (days) is the maximum days lost profit over all scenarios for all years. Data is supplied for the current parameters. Results are shown only for those participants currently protected.

Table 15 - Participant details summary

PARTICIPANT	GROSS MARGIN (%)	GAS FRACTION OF COST (%)	DWGM MAX DAYS LOST PROFIT	STTM MAX DAYS LOST PROFIT
NEW ENTRANT				
NE1	5%	30%	1524	619
NE2	5%	30%	1558	1251
NE3	5%	30%	1470	1823
NE4	5%	30%	1289	2224
NE5	5%	30%	1722	836
NE6	5%	30%	1615	1375
NE7	5%	30%	1431	1674
NE8	5%	30%	1227	1779
SMALL RETAILER				
R1	8%	32%	386	18
R2	8%	27%	408	117
R3	8%	29%	414	257
R4	8%	34%	382	421
R5	8%	32%	373	277
R6	8%	27%	401	21
R7	8%	29%	458	138
R8	8%	34%	373	282
R9	8%	32%	382	193
R10	8%	27%	401	328

PARTICIPANT	GROSS MARGIN (%)	GAS FRACTION OF COST (%)	DWGM MAX DAYS LOST PROFIT	STTM MAX DAYS LOST PROFIT
R11	8%	29%	427	24
R12	8%	34%	393	153
R13	8%	32%	392	102
R14	8%	27%	414	230
R15	8%	29%	421	384
R16	8%	34%	417	28
ESTABLISHED RETAILER				
RT1	9%	30%	317	15
RT2	9%	25%	341	98
RT3	9%	27%	349	218
RT4	9%	32%	337	372
RT5	9%	30%	337	251
RT6	9%	25%	336	17
RT7	9%	27%	343	110
RT8	9%	32%	329	249
RT9	9%	30%	318	161
RT10	9%	25%	341	280
RT11	9%	27%	325	19
RT12	9%	32%	309	121
RT13	9%	30%	313	82
RT14	9%	25%	336	187
RT15	9%	27%	342	313
RT16	9%	32%	304	21

PARTICIPANT	GROSS MARGIN (%)	GAS FRACTION OF COST (%)	DWGM MAX DAYS LOST PROFIT	STTM MAX DAYS LOST PROFIT
COMMERCIAL/INDUSTRIAL PARTICIPANTS				
C1	10%	10%	203	27
C2	10%	20%	197	158
C3	10%	30%	238	312
C4	10%	40%	316	452
C5	10%	10%	203	27
C6	10%	20%	197	158
C7	15%	30%	139	184
C8	15%	40%	191	274
C9	15%	10%	116	15
C10	15%	20%	116	93
C11	15%	30%	139	184
C12	20%	40%	93	122
C13	20%	10%	78	10
C14	20%	20%	79	64
C15	20%	30%	137	196
C16	20%	40%	133	190
INTEGRATED PARTICIPANTS				
I1	14.6%	30%	171	8
I2	13.2%	25%	211	62
I3	11.6%	27%	249	157
I4	10.8%	32%	261	289
I5	13.8%	30%	185	9
I6	12.1%	25%	235	69
I7	10.6%	27%	282	177
I8	9.7%	32%	297	329
I9	12.9%	30%	201	9
I10	11.0%	25%	273	79

PARTICIPANT	GROSS MARGIN (%)	GAS FRACTION OF COST (%)	DWGM MAX DAYS LOST PROFIT	STTM MAX DAYS LOST PROFIT
I11	9.5%	27%	323	201
I12	8.6%	32%	343	378
I13	11.6%	30%	231	11
I14	9.9%	25%	302	87
I15	8.4%	27%	375	234
I16	7.5%	32%	403	444