MARKET REFORM

GAS MARKET PARAMETERS REVIEW 2022

Final Consultation Report

26 OCTOBER 2022

AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

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 proposed methodology for the conduct of the review and presents the rationale for the approach. The methodology has been subject to industry consultation and this final methodology has been updated to reflect submissions from participant submissions. The methodology proposed in this report is that used by Market Reform for the 2018 Review though the scenarios and data are revised.

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 will be 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.

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 use simulation of scenarios to assess the level of participant risk. We simulate 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 is 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 can record the level of participant risk for different representative participant classes, each with different business structures and characteristics.

Based on study findings we can make informed and justified recommendations as to whether any parameters should change, and suggest alternative settings where appropriate. The Final Report is due for publication by 16 February 2023.

CONTENTS

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 /GJ (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/GJ

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 Market Reform's methodology for the conduct of the review and presents the rationale for the approach. The methodology has been subject to industry consultation and this final methodology has been updated to reflect submissions from 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 will 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 will be 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 as early, 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 Timeline of review

The draft recommendations will be developed on the basis of the methodology provided in this report, which has been updated to incorporate participants submissions. The Draft Decision on the recommendations will be published on 1 December 2022.

A presentation of the draft recommendations of this review will be made to the Gas Wholesale Consultative Forum (GWCF) in early December 2022.

The final report is due for publication by 16 February 2023.

1.5 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 proposed 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 are proposed to be used in the modelling.
- Section 7 provides detail of the next steps.

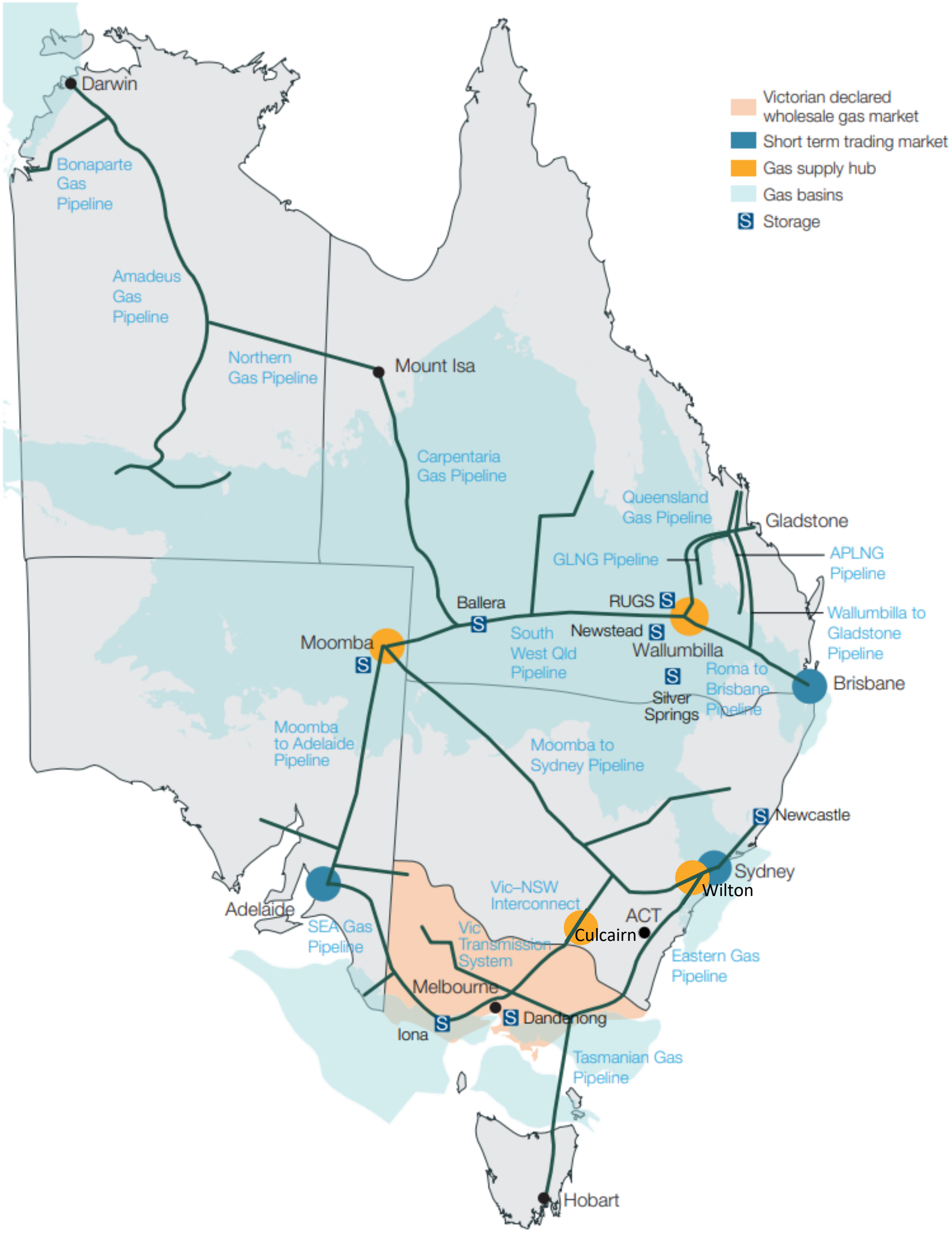
The scenarios under consideration for inclusion in the review are presented in Appendix A.

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]

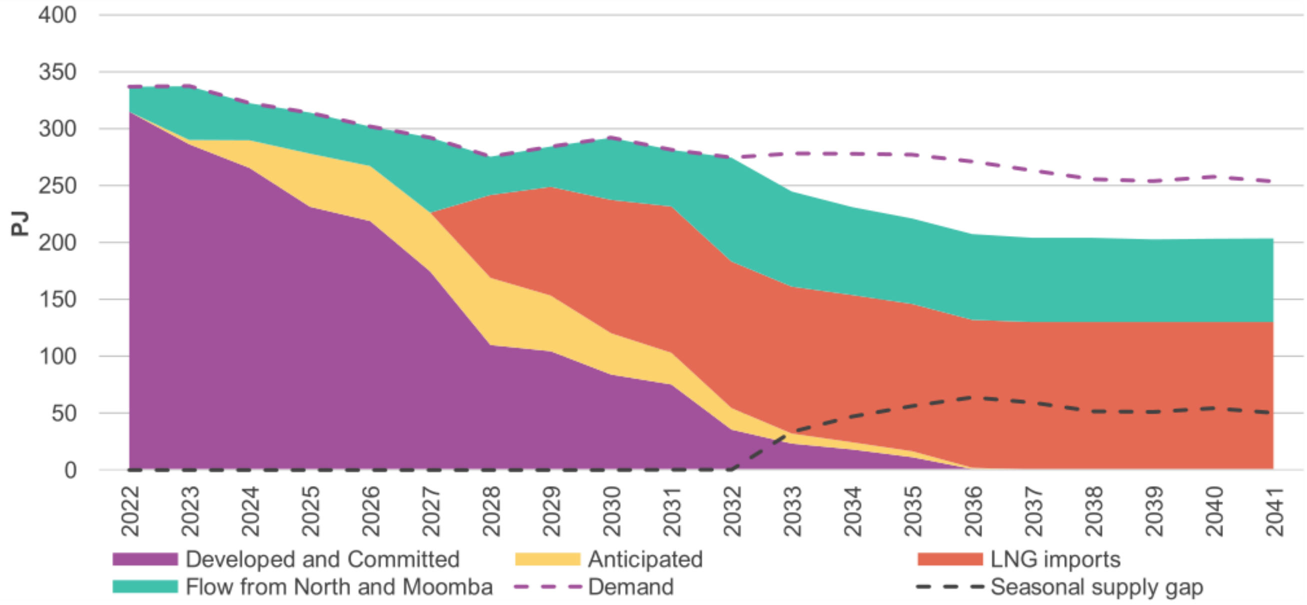
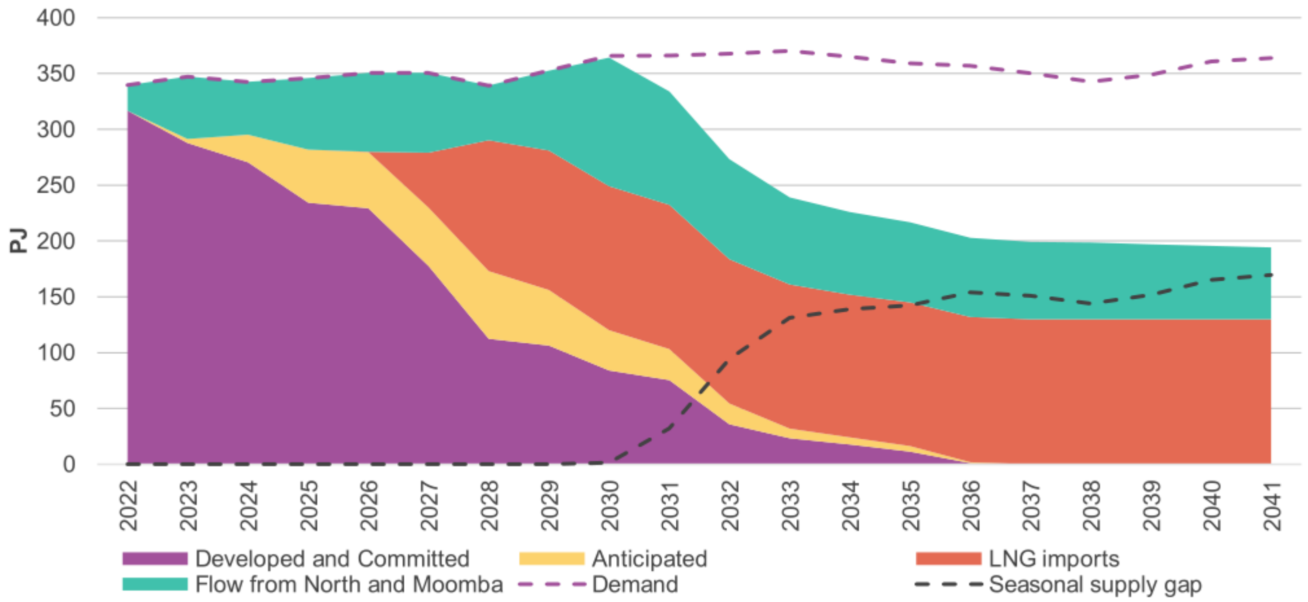


Figure 3 – Projected annual adequacy in south-eastern regions in the GSOO progressive change scenario[4]



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.

[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 will be 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 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 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 to first to the domestic market before offering it to the international market.
  - In August 2022 the ACCC reported failings and shortfalls in these arrangements in practice.[6]
  - 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.[7] 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.[8]
- 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.

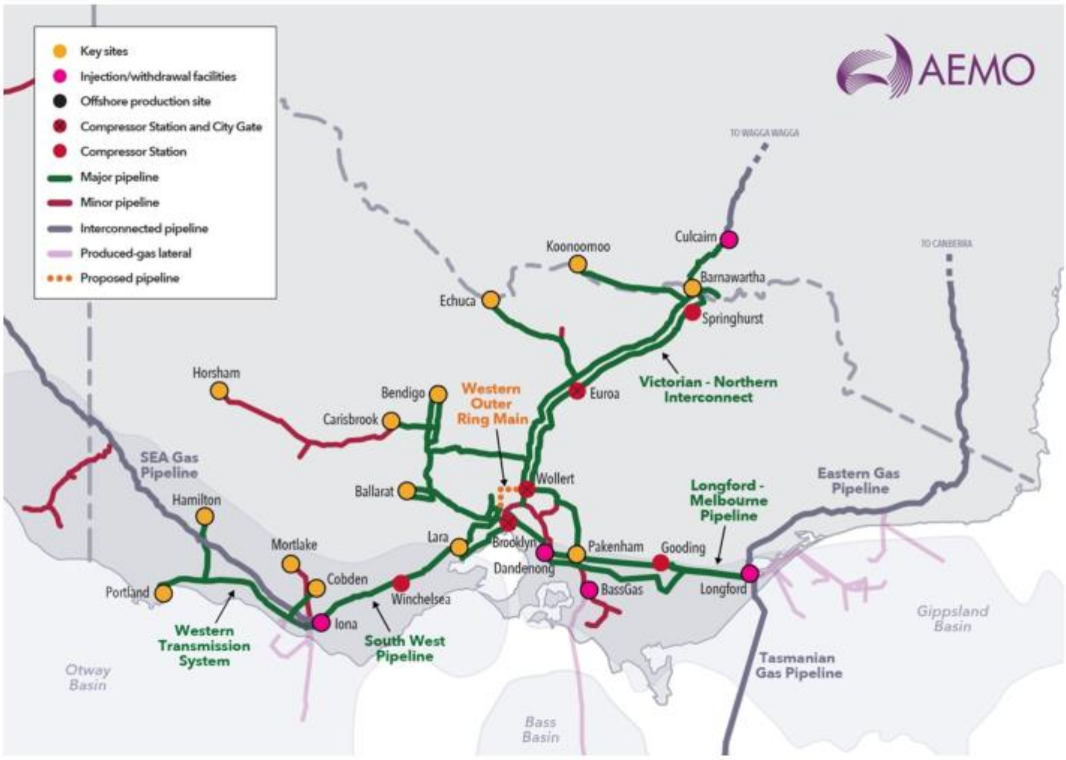
[5] The GSOO identifies Port Kembla Energy Terminal near Sydney, Golden Beach near Longford, and some additional Victorian offshore developments as being anticipated projects that would help alleviate possible supply gaps.
[6] ACCC – LNG exporters must divert gas to the domestic market to avoid shortfalls, media release, 1 August 2022.
[7] https://www.minister.industry.gov.au/ministers/king/media-releases/australian-government-secures-gas-supply
[8] https://www.industry.gov.au/sites/default/files/2022-09/heads_of_agreement_the_australian_east_coast_domestic_gas_supply_commitment.pdf

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.[9] 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)[10]



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.[11]

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[9] The red pipelines include distribution networks.
[10] Reproduced from Figure 9 of the VGPR.
[11] See Table 19 of the Victorian Gas Planning Report Update 2022 (VGPR).

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)[12], 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 Pork 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.[13]

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 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.

[12] VGPR.
[13] 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.

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 scheduling horizon of 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. The implications of this have been factored into our analysis.[14]

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[15] 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[16] 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.

In response to a rule change request by the Victorian Minister for Energy, Environment and Climate Action the AEMC has commenced a consultation[17] 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

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[14] https://www.energy.gov.au/sites/default/files/2022-08/Energy%20Ministers%20Meeting%20Communique%20-%2012%20August%202022.docx
[15] AEMC - National Gas Amendment (DWGM Improvement To AMDQ Regime) Rule 2020 Rule Determination, 12 March 2020.
[16] AEMC - National Gas Amendment (DWGM Simpler Wholesale Price) Rule 2020, 12 March 2020
[17] AEMC - Consultation Paper: National Gas Amendment (DWGM Interim LNG Storage Measures) Rule 2022, 1 September 2022.

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, Energy Ministers agreed to explore a range of actions to support a more secure, resilient and flexible east coast gas market. These actions include: [18]

- Urgent regulatory amendments that empower the Australian Energy Market Operator (AEMO) to better manage gas supply adequacy and reliability risks ahead of winter 2023.
- In the longer term, progress development of further supply adequacy and reliability measures which will help to guide how AEMO delivers its new functions.

The policy is still being developed and therefore cannot be considered in this work.[19]

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:[20]

- 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

[18] 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.

[19] We do not consider directions in this study as the focus is on market price outcomes given available supply and demand of gas based on GSOO forecasts of future conditions.

[20] Wholesale Market Administered, Pricing Procedures (Victoria) v4, AEMO, 1 July 2020.

schedule then the MCP (for the purpose of the CPT only) would be $20/GJ.[21] 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,[22] 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.[23] 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.

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[24] 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

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[21] In the modelling, constrained on injection bids will be specified exogenously based on the nature of the scenario.
[22] It is purely coincidental that the current CPT of $1400 divided by 35 periods equals the APC value of $40/GJ.
[23] As would one interval at the VoLL, followed by 34 intervals with an average price exceeding approximately $18/GJ.
[24] 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.

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[25] 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 without 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 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.[26]

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[27] 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

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

residential and C&I 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.

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[28] 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 outcome of this market is a schedule for each shipper on each pipeline and for each user to take gas from the hub. 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.

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

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 (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, and 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:[29]

- 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[30]).
- 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

[29] Administered pricing can also be triggered for operational reasons, including defined involuntary curtailment events and significant operational constraints that reduce supply.
[30] This is when the ex-ante price for the next day is determined.

cumulative price are the raw prices without application of the APC.[31] 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:

- 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.

[31] 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.

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[32]

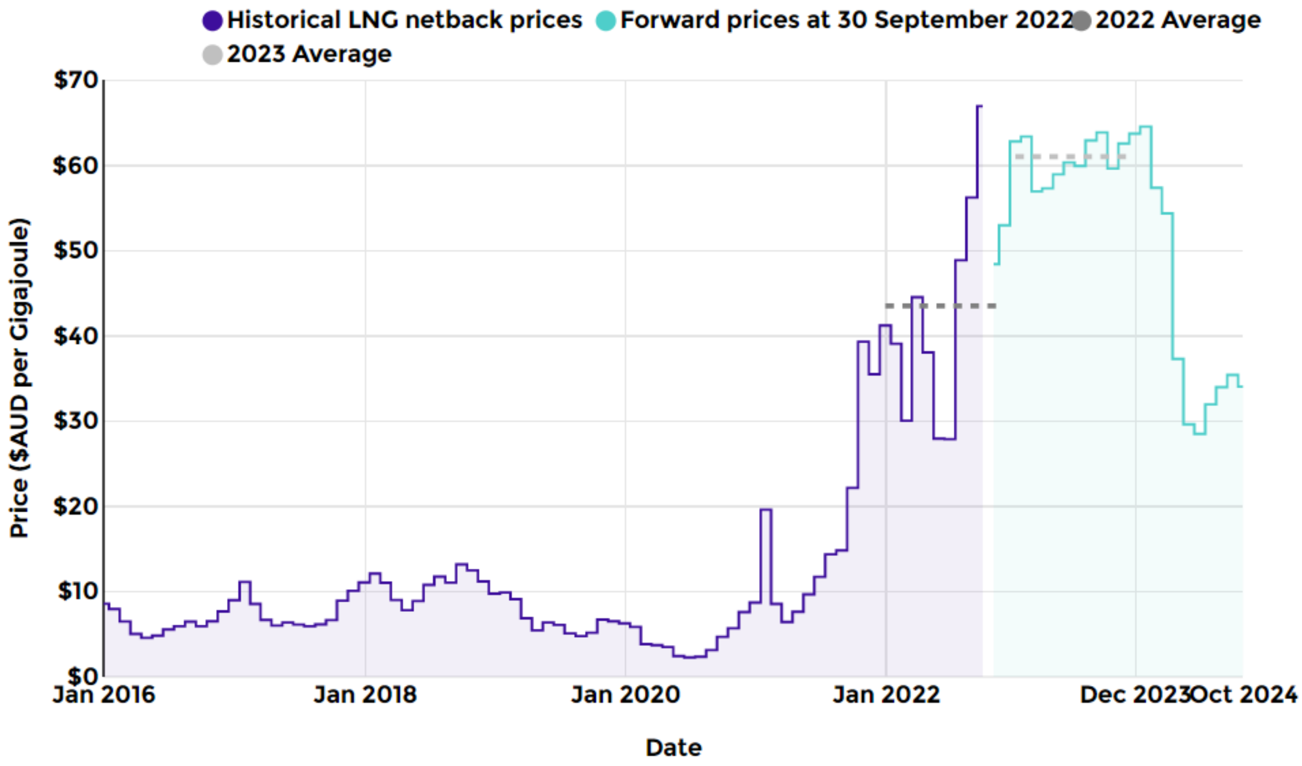
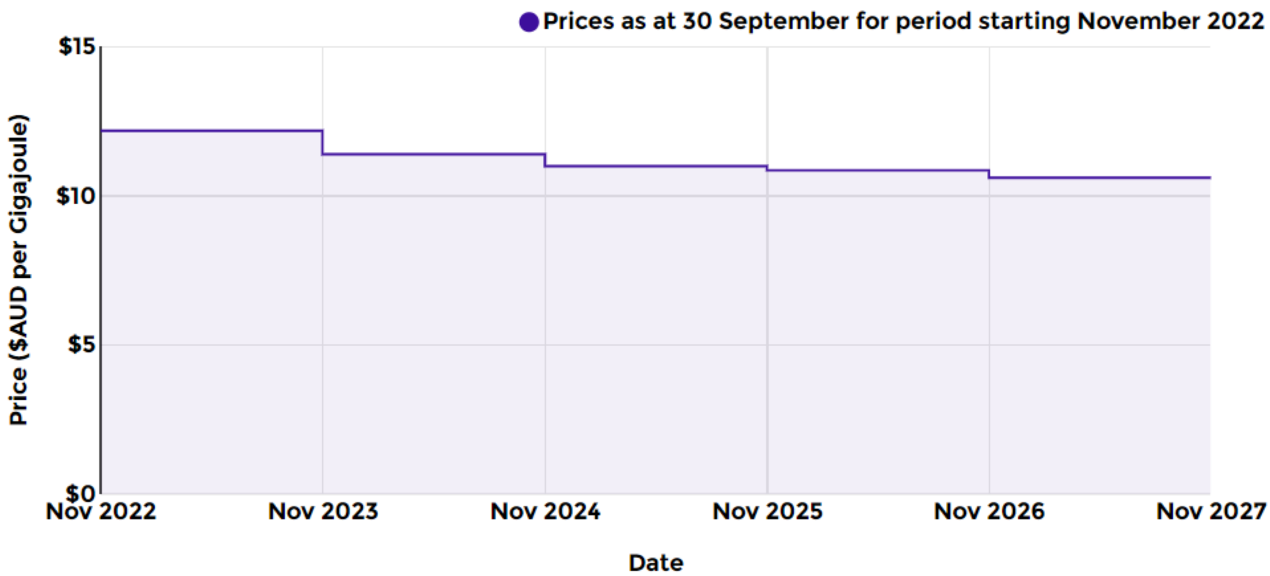


Figure 6 – Forward medium-term LNG netback prices[33]



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

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 come generate at short notice, there is a risk that the market has inadequate linepack available to serve that generation.

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.

It is note that:

- The NEM Reliability Panel has already completed its review of NEM parameters and has proposed a revised NEM APC of $500/MWh assuming the current gas market APC of $40/MWh.
- Any change to gas market parameters could have flow on implications for the pricing of electricity market contracts.

Although these points are will not specifically limit the modelling conducted in this review, they will be considered in the recommendations that come out of the review.

2.5.3 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.

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.[34] 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.

2.5.4 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 both 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.

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

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.
- 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 has been activated by AEMO. Administered pricing was also applied in the Brisbane and Sydney STTM due to a retailer of last resort event.[35]

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.

[35] This section is written largely with statistics and outcomes as reported in AEMO's Quarterly Energy Dynamics Q2 2022.

- 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.[36] 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.

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 are expected to remain 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 is set at $300/MWh.[37] 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.

A recently completed review of NEM parameters by the AEMC's Reliability Panel[38] for the period 1st July 2025 to 30th June 2028 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. 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.

[36] 2022 Review Of The Reliability Standard And Settings. Reliability Panel AEMC, 1 September 2022.
[37] The NEM has reliability price settings similar to those discussed for gas markets earlier in this report – namely the market price cap ($15,500/MWh), cumulative price threshold ($1,398,100) and administered price cap ($300/MWh), as well as the market floor price. Settings in this sentence are current for the period 1st July 2022 to 30th June 2023.
[38] https://www.aemc.gov.au/market-reviews-advice/2022-reliability-standard-and-settings-review

A rule change request has been submitted by Alinta Energy[39], which proposes to increase the NEM APC from $300/MWh to $600/MWh with a sunset period of 12 months, to reflect the prevailing fuel input costs. This higher value may be used to construct 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.

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 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, 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).[40] This might best be viewed as a new trigger mechanism across markets that applies in addition to the existing triggers within individual markets.

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[39] 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.
[40] It would make less sense in the context of a temporary local issue in one market that has no material impact on other 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:[41]

- 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.
- 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.

[41] 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.

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.[42]

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.

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 will be relevant since gas market outcomes - and hence the gas parameters themselves - will strongly influence electricity supply costs.

[42] 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.

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.[43] This 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.

[43] 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

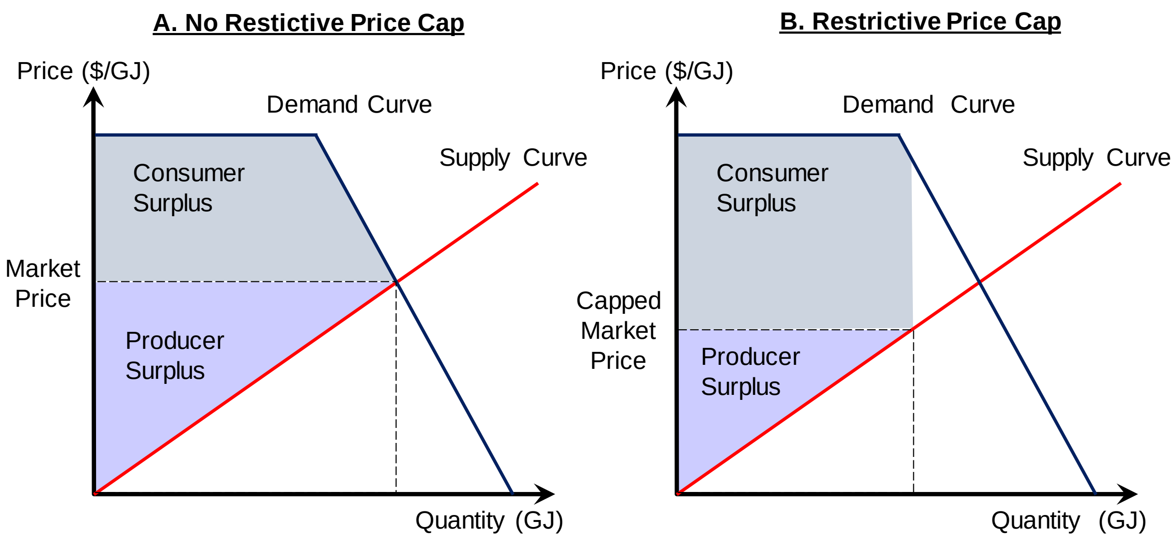
This section provides a summary of the problem that must be solved to test alternative parameter settings and provides the rationale for it. A parameter setting includes a value for VoLL or MPC, as applicable, a value for the CPT and a value for the APC.

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.[44] 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

[44] 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 propose to 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[45], 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.[46] 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.[47] 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.[48] Some participants, such as industrial users, face a

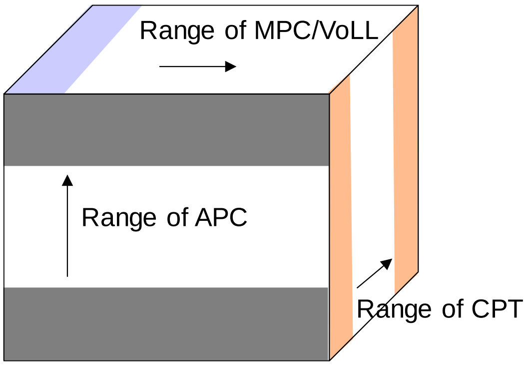
[45] Under administered pricing the gas markets do offer cost-based compensation for suppliers scheduled with costs higher than APC. However, suppliers are not guaranteed to have their costs compensated fully and may prefer to move the gas to other markets or to other days (where they can get a profit). Suppliers also may not want to reveal their costs.
[46] DWGM CPT Review, AEMO, 2013.
[47] 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.
[48] 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[49]. It will be 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.

[49] 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 PROPOSED SOLUTION METHODOLOGY

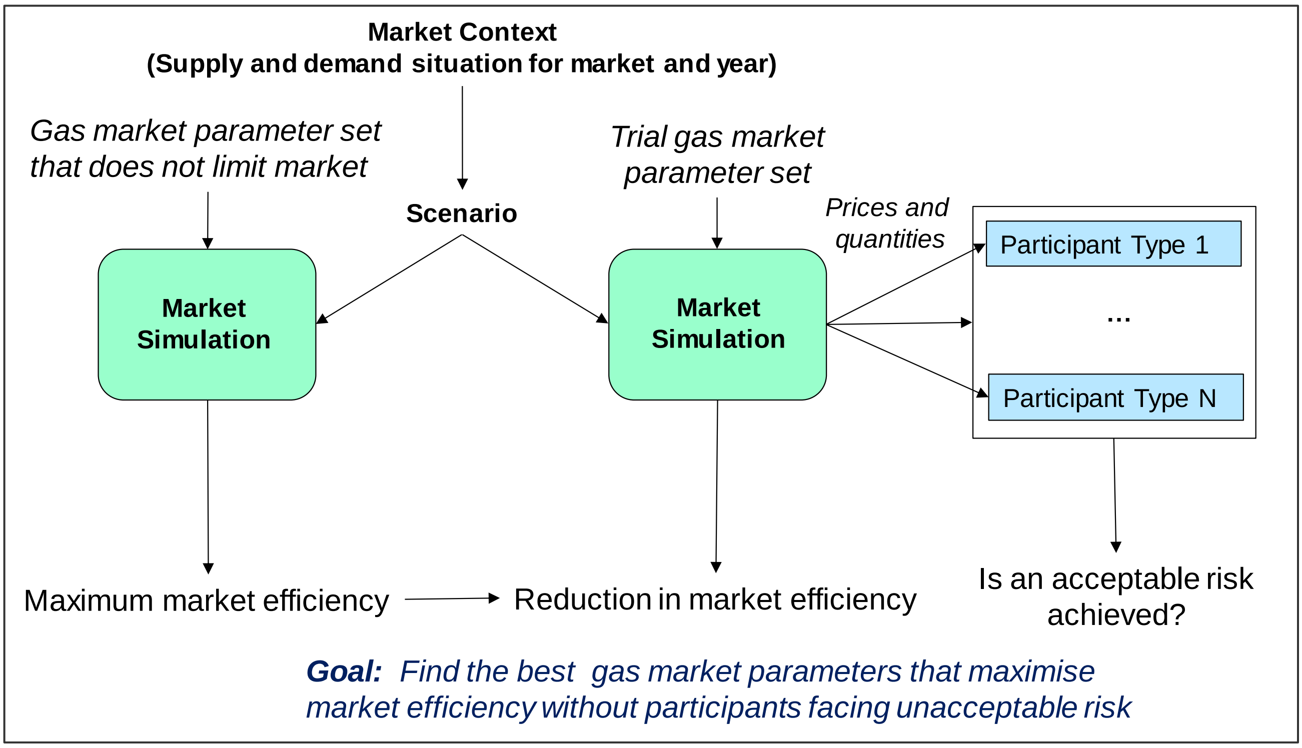
5.1 Introduction

The previous section described the structure of the parameter assessment problem. This section describes how it is proposed to solve 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:

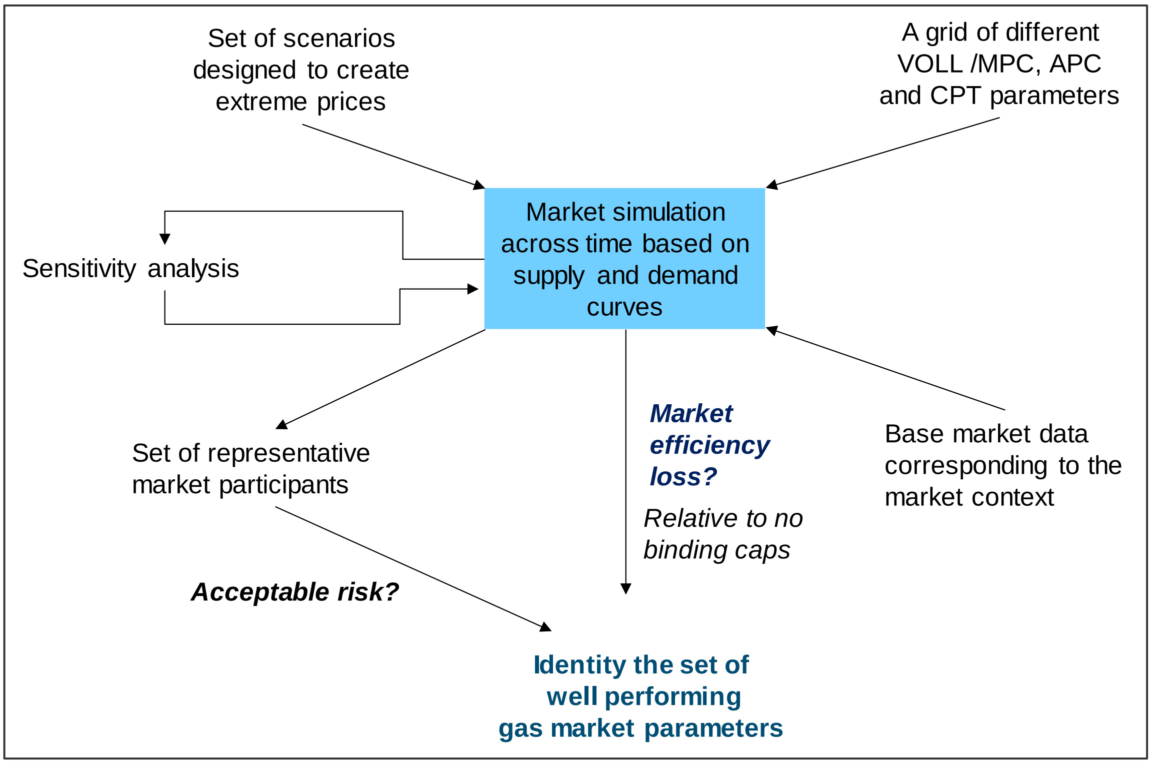
- A market context describes a specific market, in a specific year with some specific supply and demand conditions. For example, this could be the DWGM in 2023 with the supply and demand figures as forecast by the Victorian Gas Planning Report.
- A scenario represents a specific event that happens in 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 will be 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 will be considered. One variation will be 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 will be 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 will be used to implement this methodology these 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 will be different from today and will evolve across time. For this reason, it is 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 will primarily make use of the AEMO's defined Progressive Change and Step Change scenarios (described earlier in Section 2.2).

A market context of a given market will created by starting with the current market and evolving it based on forecast changes in the market. The simulations will be 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, will be simulated to provide a base reference point for what the profits of participants would be normally. This will be 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 will be a simulation of the base market context without any scenario imposed. This base market context simulation will allow the profitability of different participant types to be assessed. This will inform the analysis of acceptable risk.

Scenarios are defined relative to a specific market context – this allows 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 proposed to be explored are presented in Appendix B.

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

Two sets of day types will be considered within the period of the scenario:

- Generic base market context days. These will have normal base supply and demand curves. However, if APC is triggered then in the truncated variation of the simulation these curves will be 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 will be 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.

A scenario will involve a mixture of these days.

The scenarios we propose to use in this review 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 will be used for both DWGM and STTM. There will be 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[50] 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 will be simulated before an event, to initialise the case allow for calculation of the cumulative price.

It is not proposed to explicitly model different conditions for every schedule across the day. Rather, normally no more than two schedules will be explicitly represented. One will be the first schedule of the sequence (the ex-ante market in the STTM or the start of day scheduled in the DWGM) and this will by default be 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 will apply 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 during 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 will be 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 will always occur on a Monday and the simulation will continue to run for two more weeks, ending on the second Monday after the event.

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

The demand curve will be formed from bids for:

- Uncontrollable withdrawal (i.e. price taker demand) excluding GPG demand. For the purpose of scenario definition, this will be 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

[50] 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.

based on gas prices. The NEM price is a parameter of the scenario which will typically reflect standard pricing 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 will also be apportioned into industrial/commercial and domestic load.

The supply curve will be 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 will in the first instance be based on current market data (see Section 7). In the STTM offers will be truncated at the hub capacity, while in the DWGM they will be limited based on pipeline point constraints that restrict the total volume deliverable over a day.

Export bids, GPG bids and import offers will be 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.

The number of simulations run will be extensive – it will be necessary to run simulations for combinations of market context and scenarios, different gas market parameters, and for sensitivities. While this will generate a significant volume of data the execution should not be long as simulating a single market context and scenario is expected to take of the order of a second. It is expected that many of the cases run will produce solutions that are far from acceptable in terms of risk or market efficiency, or will fail to be able to avoid more extreme involuntary curtailment events, so the number of options that are serious candidates will not be excessive.

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 types considered will include:

- 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 will have different behaviours in the spot market. For example, a GPG will be represented as bidding in the gas market to secure gas at a price consistent with economic operation in the electricity market and will operate whenever it can secure gas and profit from it. By contrast, small retailers will effectively be price takers in the gas market. Data for participants will remain 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 will also be assumed fixed across all cases.

When a scenario occurs, the response of each participant will account for the influence on participant profitability of the incidence of growth in various demand components. Each participant will have its demand apportioned between each demand category so, for example, a small retailer with a high percentage of domestic consumers will face increase in price and quantity on a very cold day, whereas an industrial user will only face 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 are considered, covering a wide range of actual and potential future market participants.

5.7 Sensitivity analysis

Sensitivity analysis will be 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. The suggested sensitivity factors are described below, though the indicated percentages may need to be refined based on experience with the model:

- 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 will be 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 will be 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 do not apply different VoLL / MPC values to the uncontrollable withdrawal as this will introduce variations in market surplus without demand changing. Instead, we will assume 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 will give 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 being 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 already performed of the 2019 base context yields prices and market clearances that are consistent with actual results arising from the market in 2019. As the parameters are 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 will identify any simulation outcome for which involuntary curtailment occurs and will exclude such outcomes from our analysis, eliminating the potential for impact on market efficiency to rely on the level of VoLL.[51]

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.

[51] Though attempts will be made to tune the scenarios to avoid such outcomes.

Average normal daily profit is defined is 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[52], 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 will be 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, we will provide additional sensitivity around the 500-day target. This will take the form of parameter recommendations based on different options for the lost profit standard, enabling clear identification of how robust each parameter set is relative to the lost profit standard.

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.

[52] DWGM CPT Review, AEMO, 2013.

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 by higher than the values implied by such limits.

Here we focus on the investment cost relative to CPT. CPT should provide some ability to recover investment costs before the imposition of APC.

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 do not propose to explicitly model or calculate investment costs due to the complexity of doing so. Rather we propose instead to adopt 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.
- Given assumed variable and fixed cost structures and utilisation, the profit requirement can be transformed into a revenue requirement that relates directly to prices and price caps.
- Use the revenue requirement as an approximate lower bound on CPT to ensure investment is economically viable.

It should be noted that the use of CPT as a bound is only an approximation. The profit available in an event may be greater or less than the CPT, and is influenced by all three parameters under consideration. If a participant has a cost structure that allows significant profits while under APC then they may earn more than the CPT in each event. However, if APC is calibrated correctly, then there will be less opportunity for profit after Administered Pricing is activated and in this case, the CPT will closely approximate the maximum amount of revenue available in a single event, and with limited other profit opportunities this will also correspond to the maximum amount of profit available.

The STTM hubs are not directly comparable to the DWGM due to their different context. The original analysis of STTM settings[53] suggested that the lower MPC (and hence CPT) would not at that time be detrimental to investment in the context of the STTM. While our study will include the current STTM settings within the range of gas market parameter settings, during the course of the review an assessment will be made of whether the current STTM parameters are still above a threshold for investment.

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

6 KEY DATA TO BE USED IN REVIEW

6.1 Introduction

In this section we identify the data that we intend to use 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.

6.2 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 will be 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 will be based on the heat rate conversion of gas to electricity.

Adjustments of supply and demand will be 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 will be updated based on current predictions of requirements as described in the GSOO.

6.3 Scenario adjustments

Bids and offers will be 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.
- Contract data adjustments will be 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.

6.4 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.

6.5 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.

6.6 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: [54]

- 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 2 provides investment cost data for an LNG receipt facility.

Table 2 – LNG receipt investment and operating expense assumptions[55]

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 will be given to other income streams available to the facility to develop 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 is accomplished through estimation of typical profitability during non-event periods with subsequent adjustment to the capital cost to reflect the marginal component of cost that is associated with cost recovery during scenario like events.

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.

[54] 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.
[55] 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 3 shows a weighted average cost of capital (WACC) based on calculations used in prior reviews but with updated values.[56]

Table 3 – 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

[56] 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.

Efforts will be made to source more current data where possible though the same broad methods as applied in those previous studies will be used.

6.7 The grid of gas market parameters

The base grid of gas market parameters to be considered in this study is described in Table 4. 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. While we have expanded the grid based on consultation feedback it should be noted that there is a significant amount of simulation required (across all scenarios) to test any one combination of parameters and it may be impractical to consider all combinations in Table 4. Many combinations can be identified as not acceptable without simulating them. For example, if we establish that a combination of MPC, APC, and CPT is unacceptable, then there is little value in exploring grid points with an increased CPT. Hence our approach will be to identify an acceptable boundary of parameters and to explore the parameters within these bounds.

Table 4 – 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.

6.8 The NEM administered price cap

It is proposed by the AEMC's Reliability Panel that the NEM APC will be $500/MWh during the study period. We will use this value in our study. It is used in scenarios that assume APC is applied in the NEM, with the application of APC having a limiting impact on GPG gas demand.

7 NEXT STEPS

The next report will be a Draft Report on the recommended Gas Market Parameters following initial modelling.

APPENDIX A PROPOSED SCENARIOS

The following table describes the scenarios we propose to model. Many scenarios are the same or similar to those used in the 2018 gas parameter review, with changes made where necessary to make the scenarios more fitting for the study period. 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.

While scenarios are based on those in the 2018 review there are some modifications for context and clarity and the scenarios have been renumbered.

SCENARIO	MARKET & YEAR	MARKET CONTEXT	EVENT	DETAIL
1A	DWGM 2024	Progressive Change	Gippsland supply interruption	A complete outage of Longford production on a high winter demand day 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 high demand day. Output restored at midnight on the third day of the event. NEM prices are at average winter values.
2B	DWGM 2027			
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 average winter demand period. NEM prices are at high levels (circa $300/MWh) reflecting the supply interruption, but without the NEM prices being capped.

SCENARIO	MARKET & YEAR	MARKET CONTEXT	EVENT	DETAIL
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.	Peak winter week but 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			
7A	SYD 2026	Step Change	Reduced supply to hub due to upstream reduction in production.	MSP capacity to supply SYD reduced by 5%[57] at time of high winter demand but known at the time that the ex-ante market ran. Capacity reduced for three days. The 5% reduction is not enough to trigger APC for technical operating reasons. 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			

[57] 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. To avoid this situation, we limited the restrictions on supply to the Sydney STTM Hub to be no more than a 5% restriction.

SCENARIO	MARKET & YEAR	MARKET CONTEXT	EVENT	DETAIL
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 5% (not so much as to cause an Administered Pricing State of itself) after the day ahead market has run.
10B	SYD 2026			
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			

SCENARIO	MARKET & YEAR	MARKET CONTEXT	EVENT	DETAIL
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			