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Solving for ‘y’: demand shocks from Australia’s gas turbine fleet

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Abstract
The long run task of Australian power system planners is to identify the structural adjustment pathway associated with retiring the National Electricity Market (NEM) coal fleet. System planning models seek to do this at minimum cost subject to a reliability constraint. This involves the deployment of low-cost intermittent wind and solar resources with a mix of dispatchable, flexible, ‘firming’ assets. Coal’s energy-producing role is thus replaced by renewables, and firming duties by short duration batteries, intermediate duration pumped hydro and the last line of defence – gas turbine plant. As it turns out, the mix of firming assets is crucial. In this article, we examine 12 (anonymised) electricity market model forecasts in the post-coal era and find all have a surprisingly heavy reliance on gas turbines during critical event winter days. Such forecasts of gas turbine duties reflect ‘what needs to be done’, not necessarily ‘what can be done’. Using a dynamic partial equilibrium model of the east Australian gas market, we test the severity of what appear to be demand shocks from an emergent gas turbine fleet. Episodic demand shocks from gas turbines present as intractable, especially when batteries and pumped hydro plant are ‘underweight’ within the firming portfolio. As with all complex problems, resolution requires an array of policies and initiatives. Adequate time is available for policymakers to respond in an orderly manner.

Keywords: gas markets, gas turbines, renewables, firming capacity.

JEL Codes: D52, D53, G12, L94 and Q40.

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1. Introduction

The National Electricity Market or 'NEM' commenced 25 years ago at a time when coal plant dominated the aggregate supply function. In the early 2000s, the ~30GW coal fleet had 91% market share. Hydro and gas-fired generation played a relatively modest role with ~4% market share each. Until recently, the NEM was the OECD's most coal-intensive power system. This context underscores the challenge of Australia's decarbonisation task. At the time of writing, coal's market share had fallen to 56% and the renewable market share had risen to 39%.

The relative growth in NEM aggregate demand throughout the 2000s was primarily in peak periods, at which point the role of natural gas and gas turbines became more prominent (Nelson and Simshauser, 2013). Falling capital costs, short start-up and shut-down times, and relatively pliable fuel procurement (albeit at higher cost) meant the gas turbine became the optimal technology for peaking duties throughout the world's deregulated electricity markets (see Rehman et al., 2015; Guittet et al., 2016). In Australia's NEM, 35 gas turbine projects (c.$14.2 billion) were committed over the period 1998-2021, representing 9600MW of generating capacity in a market with a maximum demand of 35,000MW (Simshauser and Gilmore, 2022).

The task of decarbonisation means the power system's supply-side will experience material changes in technology, and in operating duties. Given largely inelastic aggregate demand in the medium run, the role of baseload plant may eventually become redundant following an influx of intermittent wind and solar PV (Gilmore, 2024). Coal plant minimum stable loads are incompatible with high levels of stochastic Variable Renewable Energy (VRE) output (Simshauser and Wild, 2023). The historic functions of 'intermediate plant duties' and 'peaking plant duties' may similarly be altered to collectively form 'firming duties' with the flexible, dispatchable fleet comprising short duration batteries, intermediate duration pumped hydro and gas turbines as the *'capacity of last resort'* for use during renewable droughts (see for example Gilmore et al., 2022, 2023).

In power system planning models with very high levels of VRE, the *capacity of last resort* takes on a critical role vis-à-vis power system reliability. With few exceptions, all models, and all modellers, currently rely on gas turbines to balance power system demand in a manner that meets the over-arching energy policy objective function, viz. to minimise cost subject to reliability and CO_2 emission constraints.

But the normative dynamic partial equilibrium frameworks that underpin all modern power system planning models necessarily forecast *what needs to be done.* Frequently, they are not constrained by *what can be* done, even if by way of ex-cathedra, but nonetheless reasonable, professional judgement. We examine outputs from 12 power system models and 10 modellers – 9 of which are anonymised, the other being Gilmore (2024). All models and all modellers signal sharp episodic increases in gas turbine plant duties. Crucially, all modellers assume, at least implicitly, a gas market that is *endlessly flexible.* In this sense, modellers have identified *what needs to be done*. And to be clear, the assumption of endlessly flexible gas markets has proven to be entirely reasoned and reasonable over the past two decades.

However, when we examined model results for the post-coal environment in detail, we found a surprisingly intensive role played by gas turbine plant at common points in time. The modelled output of gas turbine plant would surge in episodic periods of 5-10 days at a time during the winter months of June and July, when solar irradiation is at its lowest and east coast wind output experiences its annual nadir.

The purpose of this article is to test, ex ante, normative electricity market model assumptions by identifying the outer operating boundaries of the adjacent market for natural gas – in essence identifying *what can be done*, given known market conditions. We do so by relying on a nodal model of the Australian east coast gas market – the same model which predicted the 2018 gas market shortfalls.[1]

To summarise our results, gas turbine output during low renewable energy periods associated with winter months appears to be incompatible with the outer operating limits of Australia's eastern gas market functionality as we currently understand it. If there is any upside to our analysis, it is that sufficient time exists to reconcile otherwise intractable gas turbine dispatch duties with electricity and gas industry capacity.

This article is structured as follows. In Section 2, we present a brief review of literature. Section 3 introduces some gas market fundamentals. Section 4 provides an overview of our gas market model and inputs. Section 5 examines model results. Policy implications and concluding remarks follow.

2. Review of literature

Our literature review covers two distinct topics relevant to our subsequent analysis: i). the evolution of power system planning, and ii). the east Australian gas market.

2.1 The evolution of power system planning

The objective function of power system planning has historically focused on minimising costs subject to a reliability constraint. The optimal mix of generation plant could be identified through static partial equilibrium models dating back to Boiteux (1949), Turvey (1964) and Berrie (1967). The maths behind these static models made it possible to identify the optimal mix of base (e.g. coal, nuclear), intermediate (e.g. combined cycle gas turbines, coal) and peaking (e.g. open cycle gas turbines burning gas or liquid fuels, hydro and pumped hydro) plants against an inelastic aggregate demand function represented by a fixed load duration curve. Reserve plant margins required to meet the reliability constraint were similarly solved mathematically, with the relevant formulation first expressed in Calabrese (1947).

Later, Booth (1972) and others would devise dynamic partial equilibrium frameworks through Linear Programming models comprising security-constrained unit commitment methods which efficiently accounted for stochastic plant availability and back-solved requisite reserve plant margins to manage the *Loss of Load Probability*. In theory at least, the accuracy of plant investment programs for a given load curve were enhanced dramatically. Such models inevitably underscore the critical role of gas turbines undertaking peaking and reserve plant duties, particularly from the 1990s when their entry costs plunged relative to other forms of peaking applications (Rehman et al., 2015; Guittet et al., 2016).

Dynamic, security-constrained, unit commitment models and the associated partial equilibrium framework have long been an indispensable planning tool for power system planners. This has been amplified in the 21st century, with the objective of power system planning having been re-stated to minimising costs, subject to reliability *and* CO_2 emissions constraints. Static models can be adapted to capture the implications of early-stage intermittency (see Martin and Diesendorf, 1983), but once VRE market share exceeds ~20%, the complexity of the 'firming task' means such models break down (Simshauser and Newbery, 2023). Dynamic models thus become essential to capture the fundamental change in plant operating duties, including the fading role of the "baseload" plant:

[1] See 2018 AFR article by Matthew Stevens on Gas Shortages. The original working paper was titled "Solving for 'x': the New South Wales gas supply cliff". It was later split into two publications (see Simshauser and Nelson, 2015a, 2015b).

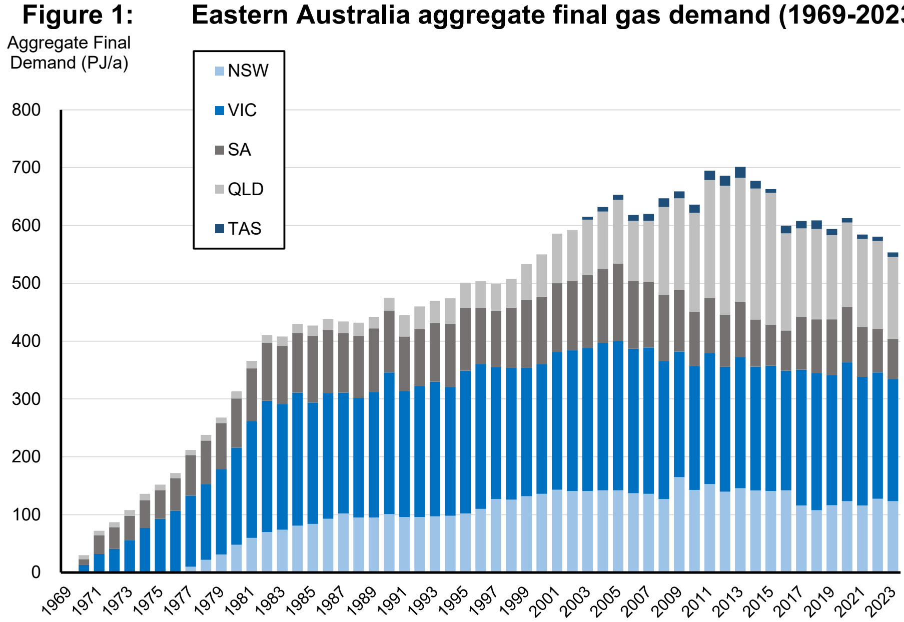
- A large, inflexible coal fleet in the presence of rapidly rising intermittent renewables can be expected to confront a rising number of negative price events (Nelson et al., 2022). This is especially prevalent in solar-rich regions. The synchronicity of rooftop and utility-scale solar during daylight hours results in falling minimum grid-supplied loads (Simshauser and Wild, 2023). Holding coal plant capacity constant, prices fall to negative levels with solar plant capable of producing to the negative of 'renewable certificate prices', and rooftop solar exports being indifferent to wholesale clearing prices.

As a result the concept of the baseload plant as an asset class, and its role in the optimal plant mix may become obsolete in regions with high solar market shares. New asset classes emerging in the NEM include renewable energy or VRE (i.e. wind, rooftop PV, utility-scale solar PV) supported by a portfolio of dispatchable, flexible 'firming plant' comprising i). short duration utility-scale batteries, ii). intermediate duration pumped hydro and iii). gas turbines as the *capacity of last resort*.

2.2 The east Australian market for natural gas

While the supply of natural gas on Australia's east coast can be traced at least as far back as 1899 in Roma (Queensland) its development at-scale occurred from the late-1960s (Vaiyavuth et al., 2008). Expansion followed quickly, as Figure 1 illustrates. Growth was driven by the fact that natural gas was a cleaner, more efficient and reliable fuel than the town gas it replaced (Taylor and Hunter, 2018).

Figure 1: Eastern Australia aggregate final gas demand (1969-2023)



Source: Simshauser & Nelson (2015b), EnergyEdge GMAT[2].

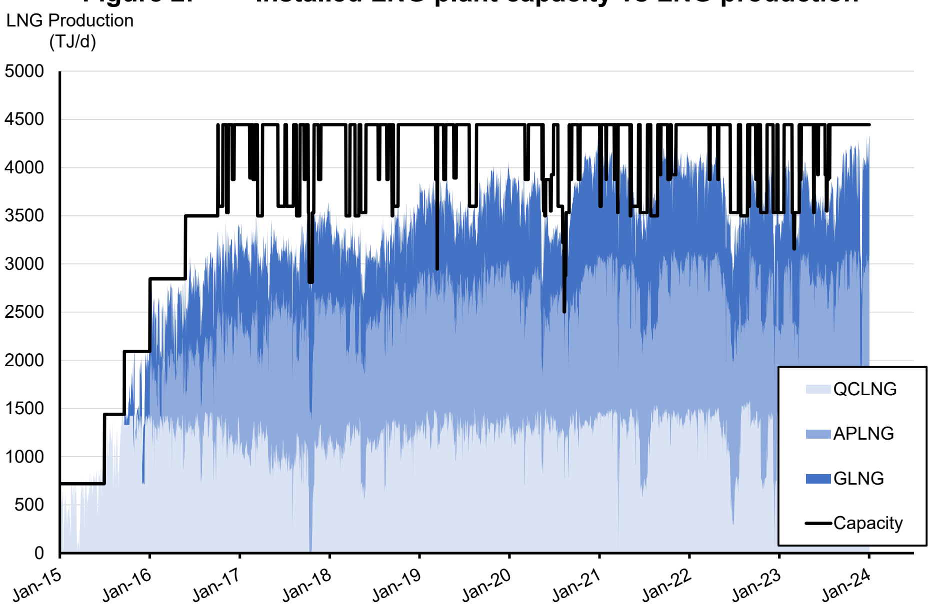
During the 1990s and early 2000s, substantial coal seam gas ('CSG') resources were discovered in the Surat Basin of southern Queensland (Towler *et al.*, 2016). By 2012, CSG 'Proven and Probable' gas reserves (known as '2P reserves') totalled 40,000+ petajoules (PJ), dwarfing the ~7000 PJ of historic conventional reserves (see Simshauser and Nelson, 2015a). These discoveries formed the foundation of a Liquified Natural Gas (LNG) export industry in Gladstone, Queensland (Billimoria et al., 2018).

[2] GMAT, or 'Gas Market Analysis Tool', is a commercial product made available by EnergyEdge (https://www.energyedge.com.au/products/gas-market-analysis-tool-gmat/).

The most prominent aspect of the run-up in 2P reserves and the associated development of the LNG export industry capacity (2007-2016) was the rapid change in market sentiment. Sentiment quickly turned from a positive economic development story to a negative one characterised by sharply rising domestic gas prices (Wood and Carter, 2013; Grafton et al., 2018; Ledesma and Drahos, 2018) and risks of domestic supply shortfalls (Simshauser and Nelson, 2015a, 2015b; Billimoria et al., 2018).

Imbalances within the east Australian market for natural gas would ultimately have material impacts for electricity market prices as McConnell and Sandiford (2020) and Nolan et al. (2022) explain. To summarise the most important elements of the literature from 2015 onwards, the consistent theme involves the 'tightly balanced' supply-demand situation for natural gas given an inherent overbuild of LNG plant capacity in Gladstone. This structural imbalance is best captured through Figure 2. Here, the ramp-up of the three LNG export terminals (comprising six LNG 'trains') over the period 2015-2016 is identified by the solid black line series, with available capacity fluctuating thereafter in line with maintenance outages. The stacked area chart illustrates LNG production by facility. Note that LNG production rarely meets aggregate LNG plant capacity, which implies plant over-capacity and an unsatisfied demand for gas feedstock. In consequence, domestic prices became inextricably linked to LNG export market prices.

Figure 2: Installed LNG plant capacity vs LNG production



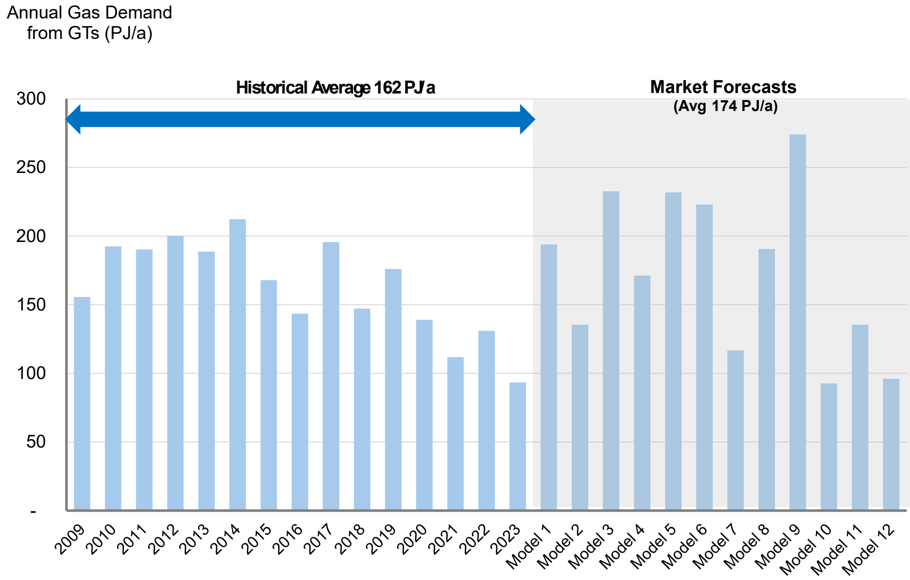
Source: Simshauser & Gilmore (2022), EnergyEdge GMAT.

3. Gas Market Fundamentals

Before commencing our quantitative analysis in Sections 4-5, it is worth highlighting what triggered our initial line of inquiry, and what we expected to find through gas market modelling. Recall from Section 1 we collated 12 power system model outputs from 10 electricity market participants and forecasters (9 of which are anonymous). Our period of interest was the mid to late 2030s, when coal generation plant is expected to have largely exited. Our focus was the forecast operational duties of gas turbine plant.

Figure 3 collates historic gas use in electricity generation (2009-2023) and compares this with the 12 forecasts of gas use by gas turbines in the 2030s. Prima facie, there is nothing spectacular about forecast gas turbine duties from the forecast models. Average gas use over the period 2009-2023 was 162PJ/a, with a range of 93-212PJ/a. Forecast annual gas consumption by gas turbines in the post-coal environment averages 174PJ/a (range 76-270PJ/a). In a market comprising aggregate final gas demand of 1900 PJ/a, prima facie these variations present as manageable.

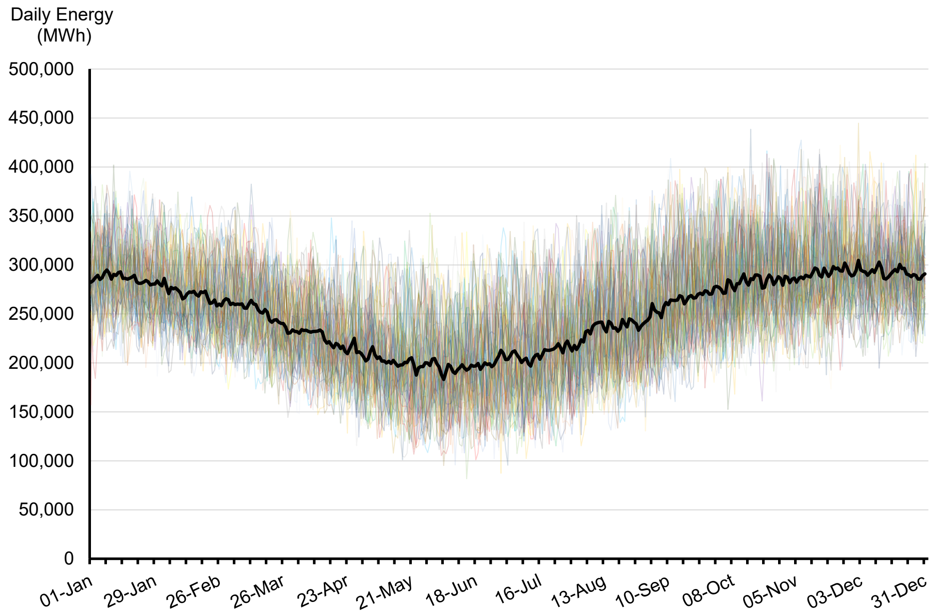
Figure 3: Historic vs Demand Forecasts for Gas used by Gas Turbines



Source: EnergyEdge GMAT (historic results)

However, aggregate annual results overlook intra-period gas use. Our interest is in gas use during winter months, and our reason for this is best explained through inspection of Figure 4. This data, from Gilmore et al. (2022), collates 80 years of historic weather data applied to an optimal combination of wind and solar PV sites throughout in the NEM following the exit of coal to simulate daily renewables based on that 80 year history.

Figure 4: NEM renewable production post-coal, based on 80 years of historic weather data



Source: Gilmore et al., (2022)

Notice in Figure 4 that throughout the winter months, and especially June and July, there is a distinct depression in renewable output. Solar irradiation is naturally lower during winter months, and as it turns out, most NEM wind resources exhibit distinctly lower capacity factors as well. Consequently, we should anticipate higher levels of firming capacity activity during winter. And if the various forms of storage (i.e. batteries, pumped hydro) are underweight, we should expect materially higher levels of production by gas turbines.

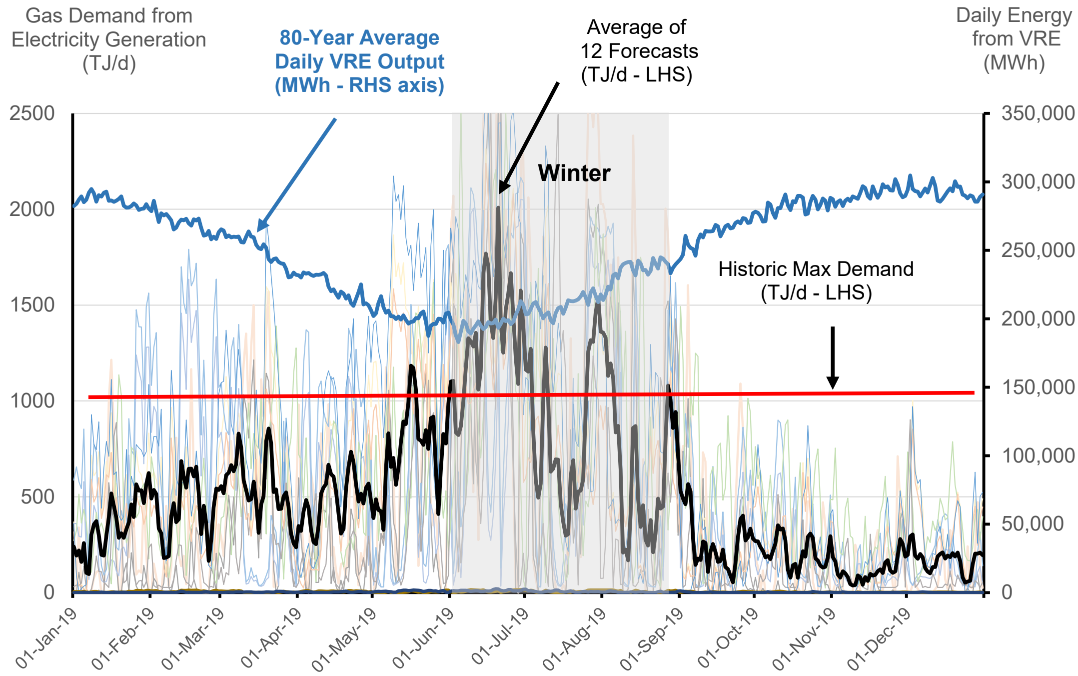
When we analysed the 12 forecast model results for the mid 2030s post-coal, we found materially elevated gas use during winter months, in all models, as expected. Figure 5 illustrates these results and has three distinct data lines:

- First, there is the red horizontal line which represents historic maximum gas demand by electricity generation, at ~1100 terajoules per day (TJ/d) - LHS y-axis.

- Second, there is the thick blue line series which illustrates the average output from the optimised NEM renewables fleet based on 80-year historic weather data (transposed from Figure 4, measured on the RHS y-axis).

- Finally, there is the solid thick black line. This is the average of the gas use by gas turbines projected by the 12 forecast models (LHS axis). The 12 scenarios are represented by the feint lines. Note some scenarios exceed the LHS y-axis.

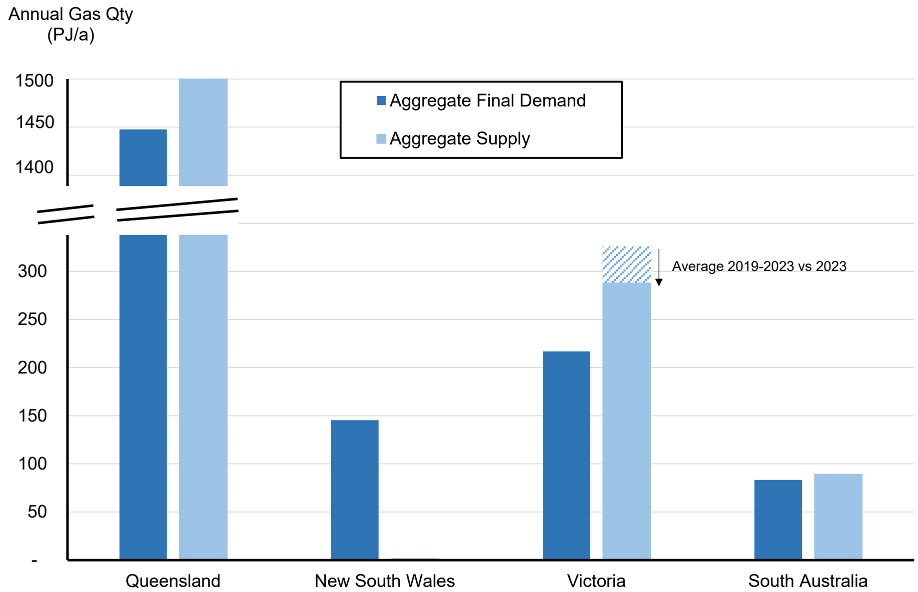
Figure 5: Gas demand from gas turbines vs renewable energy output



Results from Figure 5 suggest market stress events are likely to occur during winter months, when renewable output is naturally lower, and, when domestic gas demand reaches its annual peak (i.e. due to coincident elevated residential and commercial heating loads). It is worth identifying where the epicentre of any problem is likely to occur. By examining demand and supply by state over the period 2019-2023, historic imbalances are most pronounced in NSW (see Figure 6). And while not evident from the data, residential peak loads are highest in Victoria – a market in which local supply is anticipated to fall, according to the latest outlook from the Market Operator[3].

[3] See AEMO at https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo

Figure 6: Aggregate final demand/supply imbalance by State (avg: 2019-2023)



Source: Energy Edge GMAT.

To summarise, electricity market forecasts of the generation mix and the operating duties of plant in the post-coal environment routinely point to episodic demand shocks by the gas turbine fleet during winter months. Dynamic power system simulation models assume an endlessly flexible gas market. This context frames our modelling task – what are the operating boundary limits of the east Australian gas market?

4. Gas Market Model – 'GPE Model'

We have noted that electricity market models start by identifying *'what needs to be done'*. Considerable professional judgement is then required to constrain a model to *'what can be done'*. The purpose of our modelling exercise is to test *'what can be done'* – at least given our understanding of the capacity of the existing east Australian gas market. To summarise, our focus is on the security and reliability of the gas market given sporadic episodes of unconstrained gas demand from the NEM's emergent gas turbine fleet.

This Section outlines our model inputs and model logic. Our gas market model, known as the 'GPE Model', is a dynamic, partial equilibrium (LP) model representative of the east Australian gas market, including all major gas fields, major transmission pipelines and demand segments by location. Details are as follows.

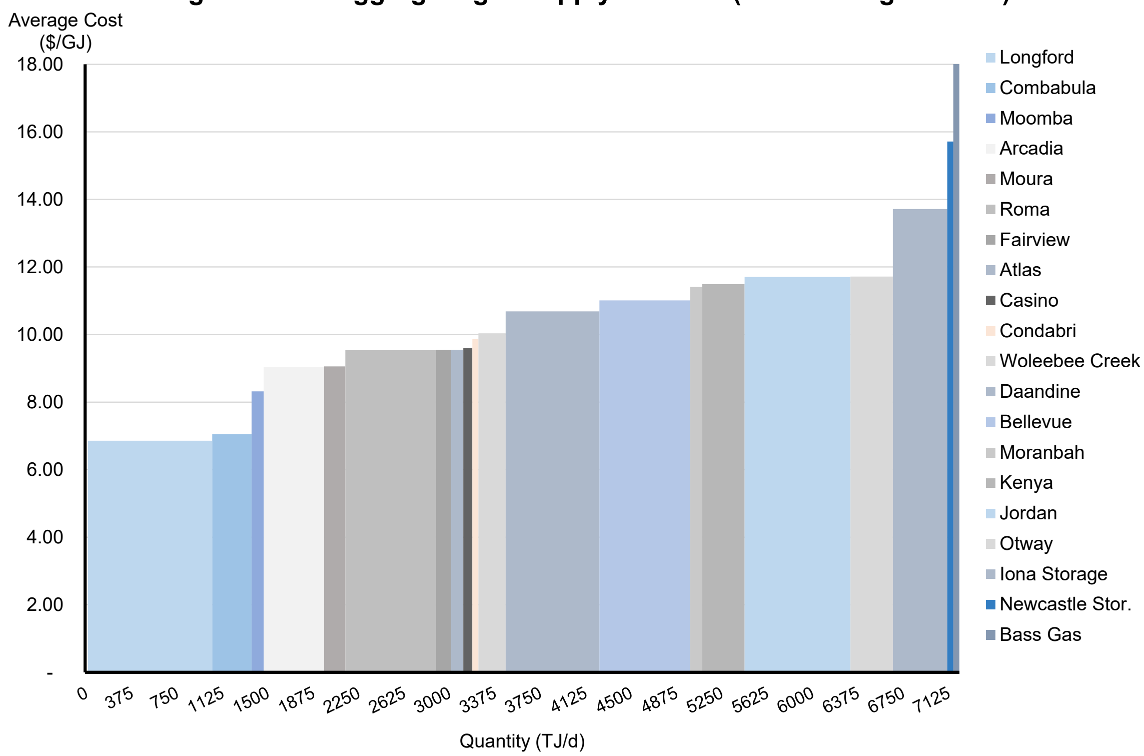
4.1 Aggregate supply function

Our model is populated with an aggregate supply function comprising all major operational gas fields on Australia's east coast in a manner consistent with data presented in Figure 6, viz. over the period 2019-2023. The detail of our supply-side is clearly set out in Figure 7. The most recent Gas Statement of Opportunities released by the Australian Energy Market Operator (see footnote #3) identifies rapidly falling supplies in Southern Australia, and the Bass Straight in particular. For our purposes, we hold the existing aggregate supply function constant. By implication, if they are not then our model results understate the problem to be solved. This is a very important caveat.

In Figure 7, each gas field or supplier is represented by their generalised long run marginal cost. Estimated short run marginal costs across fields equate to 55% of long run costs, with conventional

gas at ~35% and unconventional CSG at ~60%. The GPE Model accommodates multiple offer prices (to be paired with an offer quantity). We use two offers per gas field, viz. short run marginal costs ($/GJ) in the first offer price band paired with average annual output quantity expressed in TJ/d. The second offer
band is priced at the long run marginal cost and paired with maximum annual field output as the quantity. We assume the market to be highly competitive. In the absence of actionable mechanisms in Australia, no price on carbon has been included.

Figure 7: Aggregate gas supply function (east coast gas fields)



4.2 Gas Storage Assets

The GPE Model incorporates two critical storage assets which necessarily appear in both aggregate demand and aggregate supply functions (incl. Figure 7). The first of these is the Iona Storage facility (located at the Port Campbell node, see Figure 9), comprising 26 PJ – 8 PJ of which we treat as pad gas. The plant has an injection rate into the network of 445 TJ/d, with a re-injection rate of 140 TJ/d. The second is Newcastle Storage facility connected to the Sydney node, comprising 1.5 PJ of storage (all usable) with an injection rate of 60 TJ/d and re-injection rate of 10 TJ/d. There are other storage assets throughout the eastern gas network, but as our subsequent model results reveal, these two storage assets are critically located, and hence are of central interest to our analysis.

Scheduling of storage assets requires bid/offer prices to be nominated. We co-optimise these via an ex-ante sub-routine within the model through a simple linear programming profit maximising function which incorporates a constraint to ensure storage assets are at full capacity prior to the start of winter.

4.3 Aggregate final demand

Our model has been populated with aggregate final gas demand, daily resolution, for each gas node and each consumer segment using historic data from 2019 onwards. The GPE Model identifies three distinct consumer segments with the locational aggregate demand function:

1. gas use by domestic residential, commercial and industrial customers – collectively referred to as the 'DomGas' segment;

2. gas used in electricity generation, including gas-fired steam turbines, combined cycle gas turbines and open cycle gas turbines; and

3. gas exports by the LNG fleet, which only presents in Gladstone, Queensland.

Table 1 provides a statistical summary of aggregate final gas demand by the three consumer segments over the period 2019-2023 measured in PJ/a. Recall 2019 and 2020 are to be used as base years for our forecast simulations.

Table 1: Aggregate final demand (PJ/a) by segment (2019-2023)

Final Demand (PJ/a)	2019	2020	2021	2022	2023
DomGas (Resi, C&I)	453	464	473	478	427
Electricity Generation	138	112	85	98	72
Final Domestic Demand	591	576	557	577	499
LNG	1,216	1,328	1,411	1,357	1,370
Aggregate Final Demand	1,807	1,904	1,968	1,934	1,869

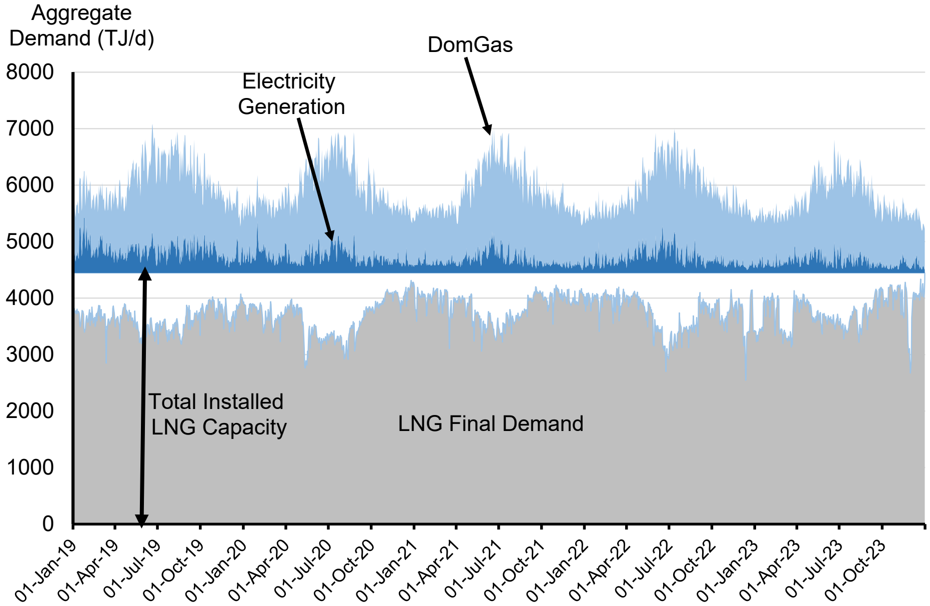
Table 2 presents *daily maximum demand* over the same period, measured in TJ/d.

Table 2: Maximum final demand (TJ/d) by segment (2019-2023)

Max Demand (TJ/d)	2019	2020	2021	2022	2023
DomGas (Resi, C&I)	2,207	2,116	2,302	2,253	1,987
Electricity Generation	988	923	737	839	563
Max. Domestic Demand	2,789	2,647	2,854	2,826	2,550
LNG	4,023	4,157	4,314	4,196	4,341
Max. Final Demand	6,287	6,144	6,375	6,300	6,066

This same data is illustrated in Figure 8. Note LNG fleet 'capacity' is distinguished from LNG 'final demand'. The grey shaded area denoted 'LNG Final Demand' depicts the gas historically consumed by the LNG terminals from 2019 whereas the white shaded area above this represents the remaining total LNG capacity. This otherwise idle LNG capacity technically represents demand for gas not satisfied due to price, gas availability, pipeline constraints, plant maintenance or some other reason. Next in Figure 8, the dark blue shaded area represents historic final gas demand from gas-fired electricity generators, while the light blue area represents historic DomGas final demand.

Figure 8: Aggregate final gas demand incl. LNG capacity from 2019



Source: Simshauser & Gilmore (2022), EnergyEdge GMAT.

Data from Figure 8, which was obtained from the energy market system 'GMAT[4]' has been loaded into the GPE Model. Data for each demand segment is available by State and node. For our purposes, we define our aggregate final demand forecast for the 2030s 'post-coal environment' simulations in our GPE Model as follows:

1. DomGas Demand: base years 2019 and 2020 (per Figure 8) are entered and then reduced throughout the entire east Australian system by -10%. This uniform reduction in DomGas demand is intended to reflect ongoing declines in the use of natural gas.

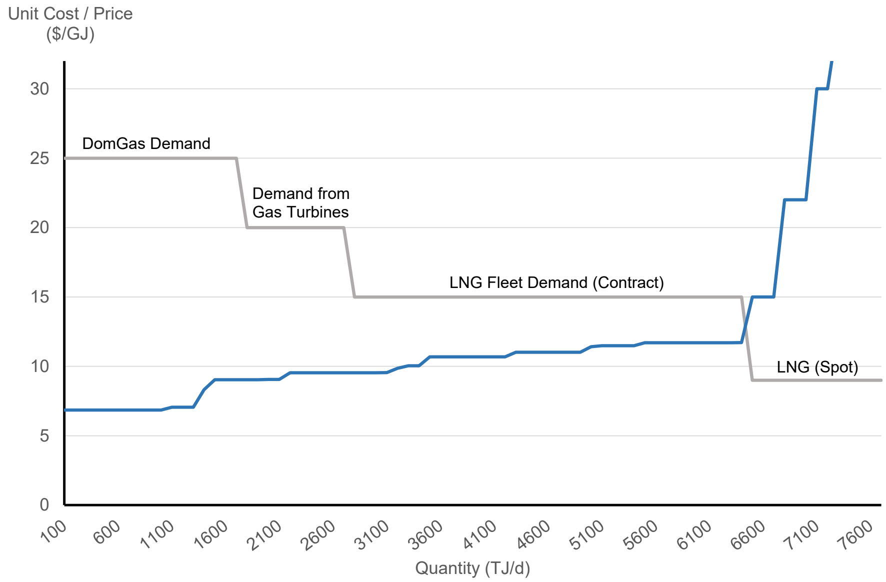
2. Historic gas use for electricity generation in 2019-2020 is removed from the dataset, and replaced by the array of forecast model results which appear in Figure 5.

3. We bid LNG final demand (grey shaded area in Figure 8) into the GPE Model at historic production levels. Additionally, we bid the idle (available) LNG capacity (white shaded area in Figure 8) at the 'netback price' of natural gas – that is, the price at which a gas producer would be indifferent as to whether they sold gas to the DomGas market, or as spot LNG cargo according to the 'JKM price' (i.e. the Japan Korea Marker[5]) after deducting LNG production and transportation costs.

Structurally, a *stylised version* of the aggregate demand and supply curves in the GPE Model for a particular day during winter, in an unconstrained state, would look as follows:

[4] See also Footnote #2.
[5] See https://www.spglobal.com/commodityinsights/en/our-methodology/price-assessments/lng/jkm-japan-korea-marker-gas-price-assessments

Figure 9: Stylised aggregate demand and aggregate supply (daily resolution)



There are two critical points to note in relation to Figure 9:

1. In all subsequent modelling and in all states of the market, DomGas demand is to be satisfied first, followed by demand from Gas Turbines. This is a crucial assumption. We assume the LNG fleet automatically adjusts demand in winter to accommodate domestic activities, the reasons for which relate to the political economy of the market for natural gas on the east coast of Australia. As an aside, we observe from Figure 8 that historic final LNG and DomGas demand (2019-2022) are strongly negatively correlated (-0.63).

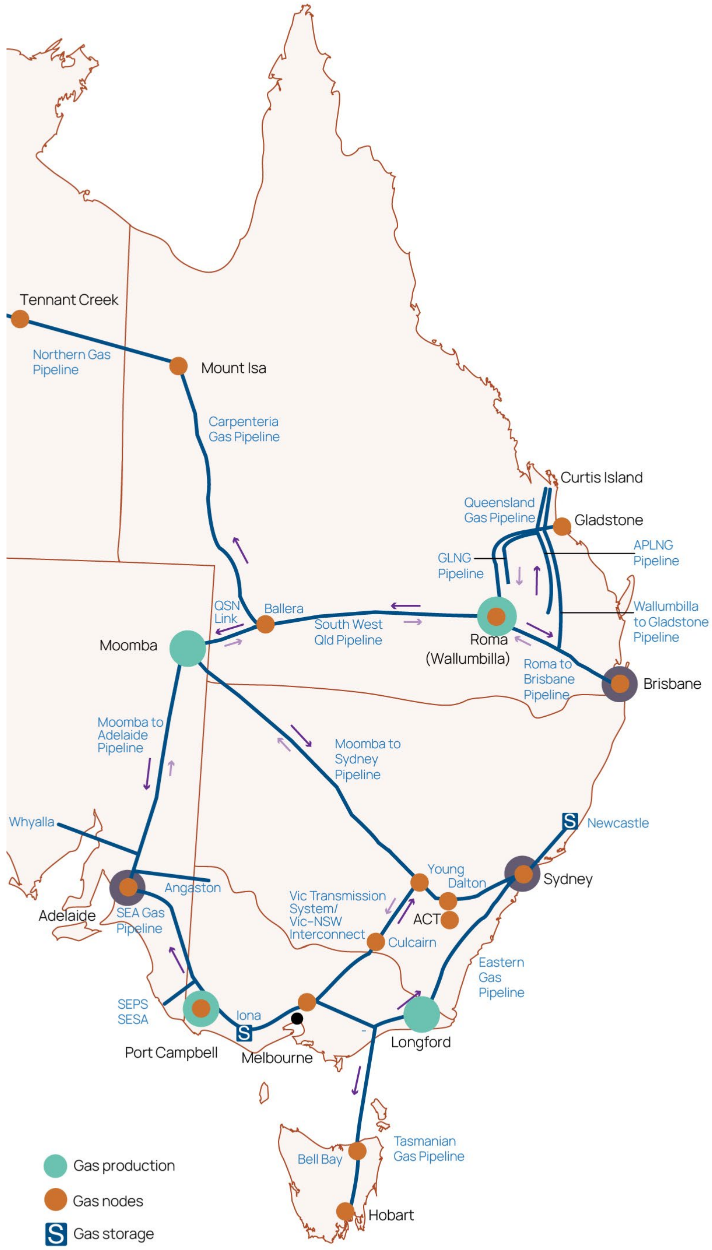
2. Consistent with the shape of the aggregate demand function outlined in Figure 9, we assume LNG demand *is* endlessly flexible. By implication, the only reason DomGas and/or Gas Turbine demand would not be satisfied is due to constraints within the gas network for a given level of demand. That is, demand shocks may exceed shipping capacity on some elements of the gas network.

At this point, it is appropriate to introduce the shipping capacity constraints of the east coast gas network, as reflected in our GPE Model.

4.4 GPE Model structure

The east Australian gas market spans from Tennant Creek in the Northern Territory, through to Queensland including major gas fields near Roma and LNG export terminals at Gladstone, then down to the southern markets of South Australia (Moomba fields), New South Wales, Victoria (Longford and Port Campbell production) and Tasmania. Figure 10 illustrates key demand centres, gas fields and gas transmission pipelines contained in our GPE Model.

Figure 10: GPE Model demand centres, gas fields and pipelines



Details of the gas transmission pipelines, pipeline lengths, connecting nodes, pipeline capacity (TJ/d) and pipeline tariffs (expressed in $/GJ) appear in Table 3. Given the number of pipeline routes and nodes, there are 286 plausible supply combinations and associated constraint equations along with 834 variables to solve in each trading interval (i.e. daily resolution).

Table 3: Pipelines and Pipeline Capacity

Gas Pipeline	Pipeline Name	Length (km)	From Node	To Node	Max Flow (TJ/d)	Tariff ($/GJ)
(t_j)			(η_i)	(η_i)	(fc_i)	$(\bar{p}_k)$
CBR	Canberra to Dalton	58	Dalton	Canberra	52	$1.23
CGP	Carpentaria Gas Pipeline	840	Ballera	Mt Isa	119	$1.34
EGP	Eastern Gas Pipeline	797	Longford	Sydney	362	$2.90
LMP	Longford to Melbourne Pipeline	174	Longford	Melbourne	1030	$1.99
MAP	Moomba to Adelaide Pipeline	1185	Moomba	Adelaide	249	$0.83
MSP	Moomba to Sydney Pipeline	1300	Moomba	Sydney	446	$1.23
NVI	NSW - Victoria Interconnect	88	Culcairn	Young	223	$1.60
NVI_1	NSW - Victoria Interconnect	62.5	Melbourne	Culcairn	223	$1.60
QGP	Queensland Gas Pipeline	627	Wallumbilla	Gladstone	145	$1.08
RBP	Roma to Brisbane Pipeline	438	Wallumbilla	Brisbane	167	$0.63
SEAGas	South East Australia Gas Pipeline	689	Pt Campbell	Adelaide	314	$0.95
SWP	South West Pipeline	202	Pt Campbell	Melbourne	517	$2.31
QSN	QSN Link Pipeline	182	Ballera	Moomba	404	$1.34
SWQP	South West Queensland Pipeline	755	Wallumbilla	Ballera	404	$1.34
TGP_1	Tasmanian Gas Pipeline	740	Longford	Bell Bay	129	$2.55
TGP_2	Tasmanian Gas Pipeline	248	Bell Bay	Hobart	129	$2.55
APLNG	APLNG Pipeline	362	Surat	Gladstone	1700	$1.15
QCLNG	QCLNG Pipeline	543	Surat	Gladstone	1588	$1.15
GLNG	GLNG Pipeline	420	Surat	Gladstone	1400	$1.15
NGP	Northern Gas Pipeline	622	Tennant Creek	Mt Isa	106	$1.59

Sources: Simshauser & Nelson (2015a), AEMO.

4.5 Model Logic

The GPE Model is a template interconnected gas system model that can be modified to represent local market conditions. The GPE Model assumes gas can be shipped from any supplier to any consumer subject to pipeline constraints, along with any gas shipper nomination constraints specified. The model is grounded firmly in welfare economics, and ultimately seeks to maximise welfare in the market for natural gas. This objective is formally implemented by maximising the sum of consumer and producer surplus after satisfying differentiable equilibrium conditions. Model logic is as follows.

Nodes, Demand and Supply

In the GPE Model, let $\mathbb{N}$ be the ordered set of nodes in our interconnected gas market with $|\mathbb{N}|$ being the total number of nodes in the set. Let η_i be node i where

$$i \in (1..|\mathbb{N}|) \wedge \eta_i \in \mathbb{N}, \tag{1}$$

Let Q_i be the aggregate maximum demand for all consumer segments at node η_i expressed in TJ/d. Let Ψ_i be the set of gas suppliers at node η_iLet $\bar{\mathrm{P}}\psi_i$ be the maximum productive capacity of supplier ψ_i at node η_i, expressed in TJ/d. Let $\rho\psi_i$ be the quantity of gas supplied at node η_i by supplier ψ_i where

$$\psi_i \in (1..|\Psi_i|), \tag{2}$$

Let c_i be the quantity of gas delivered to node η_i, expressed in TJ/d.

Pipelines

In the GPE Model, let Y be the ordered set of pipeline segments in the system and $|Y|$as the number of pipeline segments in the set. Let y_i connect to node j where

$j \in (1..|Y|) \wedge y_i \in (1..|Y|),$ (3)

Let Ʊ_j and Ɣ_j be the two nodes that are directly connected to pipeline segment y_i where

$\text{Ʊ}_j \in \text{N}, \wedge\ \text{Ɣ}_j \in \text{N}\ |\text{Ʊ}_j \neq \text{Ɣ}_j,$ (4)

Let f_i be gas flow on pipeline segment y_i from Ʊ_j to Ɣ_j expressed in TJ/d.

Let R be the ordered set of all paths. Let R_k be path k between two nodes η_x and η_y. Let r_{kj} be node j in path R_k where

$j \in \ (1..|R_k|) \wedge r_{kj} \in R_k,$ (5)

Let Y_r be the ordered set of pipeline segments in path R_k. Let y_{kj} be pipeline segment j in path R_k where

$j \in \ (1..|R_k|) - 1,$ (6)

Let fc_i be the maximum allowed flow along pipeline segment y_i. Let fm_i be the minimum allowed flow along pipeline y_i. Let fr_i be the flow of gas along path R_k. And let p_k be the cost of shipping 1 unit of gas (i.e. 1 TJ of gas) along path k, *subject to:*

$\forall \mathrm{k}, \mathrm{w}, \mathrm{x},\ \mathrm{r}_{kw} \neq r_{kx} | w \neq x,$ (7)

and

$\exists y_i \big| \text{Ʊ}_j = \mathrm{r}_{ki} \wedge\ \text{Ɣ}_j = r_{k(i+1)} \vee \big(\text{Ɣ}_{jg} = r_{ki} \wedge \text{Ʊ}_j = r_{k(1+i)}\big),$ (8)

The purpose of equation (7) is to ensure that each node appears only once in a path, while the purpose of equation (8) is to ensure that all nodes are connected to the pipeline network. The flow on any given pipeline is the sum of flows attributed to all paths (that is, forward flows *less* reverse flows) as follows:

$f_i = \sum_{k=1}^{R} fr_k |\, y_i \in R_K, \exists w{:}\, \text{Ɣ}_i = r_{kw}^{\text{Ʊ}_i} = r_{k(w+1)} - \sum_{k=1}^{R} fr_k |\, y_i \in R_K, \exists w{:}\, \text{Ʊ}_i = r_{kw}^{\text{Ɣ}_i} = r_{k(w+1)},$
(9)

The clearing vector of quantities demanded or supplied (including from storage facilities) in node $i = 1..n$, is given by the sum of flows in all paths starting at that node, less flows in paths ending at that node if applicable:

$q_i = \sum_{k=1}^{R} fr_k |\, \eta_i = r_{k1} \ - \sum_{k=1}^{R} fr_k |\, \eta_i = r_{k|R_k|},$ (10)

Net positive quantities at a node are considered net supply $\rho\psi_i$ and negative quantities imply net demand c_i:

$if\ q_i \begin{cases} \geq 0, \rho_{\psi i} = q_i \\ \leq 0, c_i = -q_i \end{cases},$ (11)

Demand Functions

Let $C_i(q)$ be the valuation that consumer segments at node η_i are willing to pay for quantity (q) TJ of gas. We explicitly assume demand in each period i is independent of other demand periods. Let $P_{\psi i}(q)$ be the prices that supplier ψ_i expects to receive for supplying (q) TJ of gas at node η_i.

Objective Function:

Optimal welfare will be reached by maximising the sum of producer and consumer surplus, given by the integrals of demand curves less gas production and pipeline costs. The objective function is therefore formally expressed as:

$$\text{Obj} = \sum_{i=1}^{|N|} \int_{q=0}^{c_i} C_i(q)dq - \sum_{i=1}^{|N|} \sum_{\psi=1}^{\Psi(i)} \int_{q=0}^{\rho\psi_i} \rho\psi_i(q)dq - \sum_{k=1}^{R} f_k.p_k \qquad (12)$$

Subject to:

$$\text{fm}_i \leq f_i \leq fc_i$$

$$0 \leq c_i \leq Q_i$$

$$0 \leq \rho\psi_i \leq \bar{\text{P}}\psi_i.$$

5. Model Results

In Figure 5, we identified apparent demand shocks from an emergent gas turbine fleet. These spikes in demand appeared at various levels of intensity across all 12 electricity market forecasts. State gas imbalances identified in Figure 6 revealed NSW is likely to be a vulnerable region. We therefore start our modelling sequence in Section 5.1 by examining the most significant demand shock scenario in our forecast models. This scenario from Gilmore (2024) forms one of the 12 results in Figure 5 and can be briefly described as one in which renewable targets are met, coal plant closures occur as scheduled, but no new pumped hydro plant (beyond the committed Snowy 2.0 and Kidston pumped hydro) is developed. Based on assumed cost reductions in renewable and battery technologies, in the absence of gas constraints, the least cost build in the NEM scenario incorporates a 16GW gas turbine fleet within the 100GW aggregate supply-side. If there are likely to be gas shortfalls, surely this 'worst case' scenario would reveal a potential problem. Thereafter, we model 5 subsequent scenarios in order to examine the nature and timing of the gas market dynamics we identify.

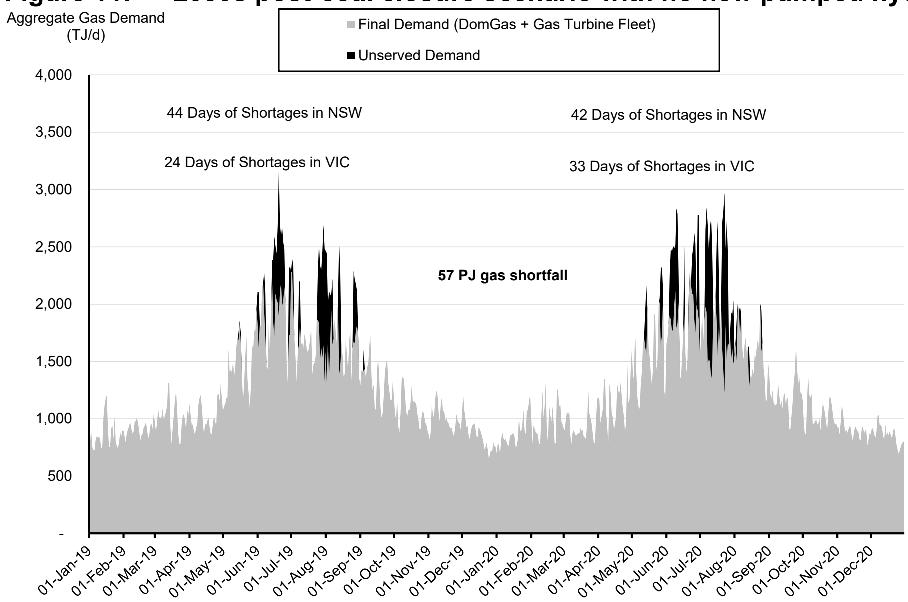
5.1 NEM with no new pumped hydro and reliance on gas turbines

In the 'no new pumped hydro scenario', annual gas used by the gas turbine fleet equates to ~194 PJ/a. Prima facie, there is nothing spectacular about 194 PJ of gas use in a single year – it sits neatly within the bounds of historic gas generation outcomes as illustrated in Figure 3 (i.e. recall the historic range from 2009-2023 was 93-212 PJ/a). However, this scenario exhibits as much as ~3000TJ/d of gas demand from gas turbines alone during critical event days on a NEM-wide basis (cf. 1100TJ/d historically).

Due to the diurnal and seasonal pattern of renewables, limited storage capacity of (4-hour) batteries (which were uneconomic to provide reserve energy for infrequent events) and no new pumped hydros being developed beyond Snowy 2.0 and Kidston, aggregate storages in the power system and the gas market are quickly and routinely exhausted early in the winter months. This scenario is unique, and not contemplated by other modellers or the Market Operator in its annual Integrated System Plan (AEMO includes ~8GW of pumped hydro in its forecasts). GPE Model results for the east Australian gas market for this scenario are illustrated in Figure 11.

In Figure 11, the first point to note is that 'Final Demand' is represented by the light shaded grey area and represents the combined 'demand served' for DomGas and the Gas Turbine Fleet. Conversely, 'Unserved Demand', depicted by the dark-shaded area, represents that component of gas turbine demand for natural gas which exceeds modelled system capacity..

Figure 11: 2030s post-coal closure scenario with no new pumped hydro



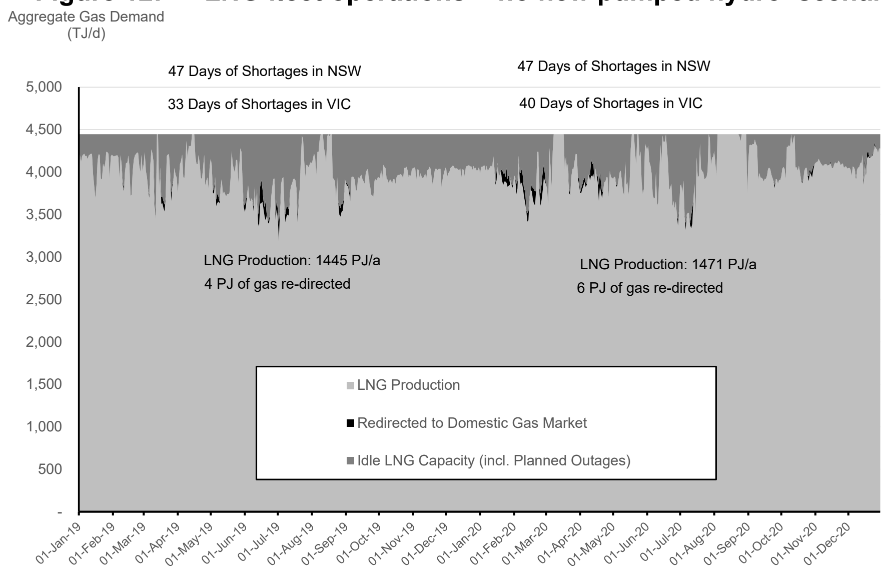
In Figure 11, unserved gas demand is very extensive. In aggregate across the two-year window, shortfalls equate to 57 PJ (26 PJ in year 1, 31 PJ in year 2). NSW is forecast to experience more than 40 critical events per annum, and somewhat unexpectedly, Victoria is forecast to experience more than 20 days of shortfalls per annum as well. It is to be noted that we have excluded event days in which demand shortfalls were less than 100TJ/d – our thinking being gas linepack would adequately resolve these. If <100TJ event days are included, NSW critical event days rise to ~55 per annum.

Recall our assumed merit order of demand (Figure 9) ranks DomGas and Gas Turbine segments ahead of LNG segment demand. The model assumes this occurs routinely due to the political economy of unserved gas demand and the adverse implications for the reliable supply of electricity. Consequently, if it was merely a matter of inadequate availability of natural gas, the model would curtail LNG facilities' consumption and re-direct their feedstock to the DomGas/electricity generation market.

Figure 12 illustrates the modelled impacts on LNG fleet operations. As it turns out, during the first simulated year the LNG fleet redirects just 4 PJ (out of its 1449 PJ demand schedule) to the domestic market in accordance with the merit order of demand. This occurs to varying degrees on 44 specific trading days, although crucially only 22 of the 44 days coincide with physical shortage events in southern markets. In other words, shortage events would be even more amplified were it not for the flexibility assumed by the LNG fleet.

During the second simulated year, the result is 6 PJ across 65 days, and curiously, only 5 of the 65 days coincided with critical event days in NSW. The most important implication of this is that the remaining 47 PJ of shortages across the two years are pipeline and/or local production and storage-deficit related events. The problem of unserved demand is thus more structural.

Figure 12: LNG fleet operations - 'no new pumped hydro' scenario



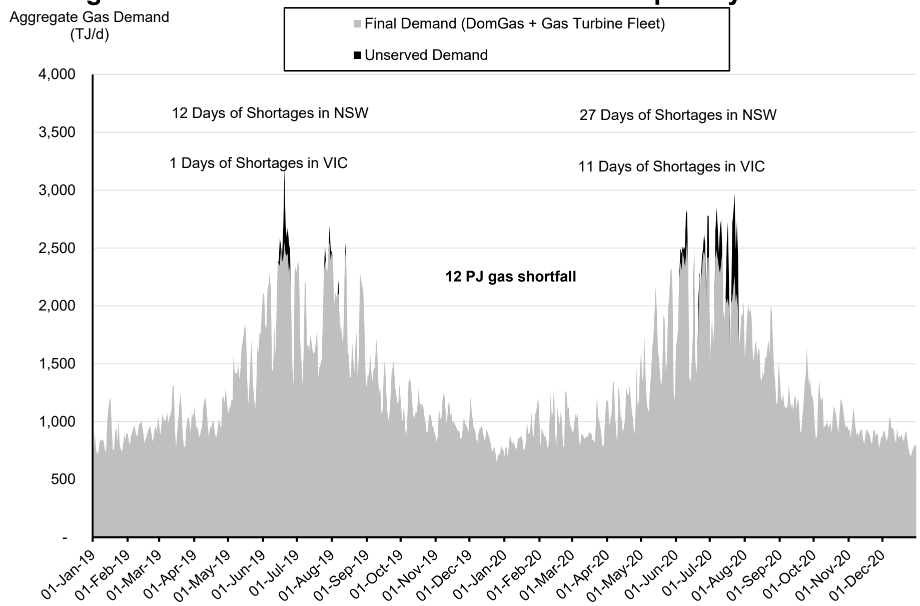
Detailed model results reveal the two critical gas storages are largely exhausted by early July each year, given total gas market loadings (see chart at Appendix I, Figure A-1). Furthermore, there are extensive pipeline constraints across the Moomba to Sydney Pipeline (~80 days per annum), Longford to Melbourne pipeline (~35 days per annum), South-West Pipeline (Port Campbell to Melbourne, ~28 days per annum), and the Southwest Queensland Pipeline and QSN Link (Wallumbilla to Ballera and through to Moomba, ~25 days per annum).

5.2 Impacts of low-cost batteries and '3PC' pumped hydro

In Gilmore (2024), the scenario with the lowest reliance on gas turbine plant in the post-coal environment was one in which both batteries and pumped hydro were at their lowest cost base. Here, 2040 projected (falling) battery costs were brought forward as if delivered by 2030, and capital-intensive pumped hydro plant was assumed to benefit from the '3-Party Covenant' (3PC) financing structure outlined in Simshauser and Gohdes (2024), which has the effect of reducing intermediate duration storage costs significantly. Lower storage costs result in more storage capacity being added to NEM model outcomes. This particular scenario therefore includes ~11GW of pumped hydro (average 18-hours duration), ~5GW of batteries (average 4-hours duration), with lower gas turbine capacity (11GW) and operating duties. GPE Model results for this scenario are illustrated in Figure 13.

The first point to note from Figure 13 is that the restructuring of the electricity market supply side materially reduces the frequency and intensity of strains placed on the gas market – far more than the number of Unserved Demand critical event days might suggest. Measured unserved demand across the two-year window reduces by ~80%, from 57 to 12 PJ. Furthermore, critical event days reduce by 65% from 143 to 51 days. However, Unserved Demand has not been eliminated and the source is once again constraints associated with the Moomba to Sydney Pipeline (~55 days per annum), Longford to Melbourne pipeline (~12 days per annum), South-West Pipeline (Port Campbell to Melbourne, ~26 days per annum), and the Southwest Queensland and QSN Pipelines (10-20 days per annum).

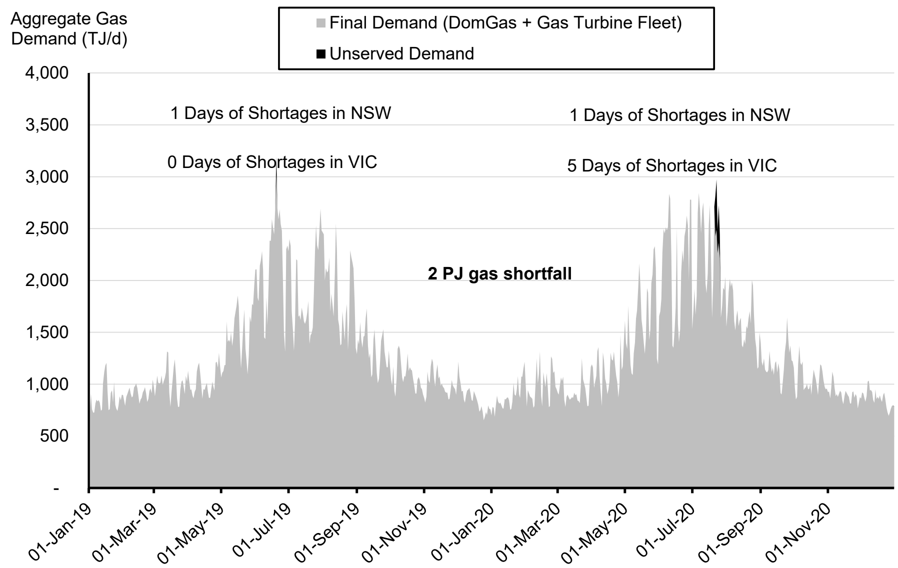
Figure 13: Low-Cost Batteries and 3PC Pumped Hydro scenario



5.3 Adjusting pipeline capacity: *Solving for 'y'*

Recall from Section 4 that in our GPE Model, the variable 'y' represents the various gas pipelines. Given residual episodes of Unserved Demand in Figure 13, our next scenario alters specific pipeline capacities (SWQP and QSN in Queensland, MSP in NSW and SWP in Victoria) by ~200TJ/d each, in addition to the adoption of 3PC financing for Pumped Hydro. The cost and practicality of these augmentations is beyond the scope of our research, but the line of inquiry is obviously important. Two primary implications follow. First, with better pathways, gas storages prove to be more durable throughout the winter months, albeit still being exhausted prior to winter's end (see Appendix 1, Figure A-2). Second, critical event days are largely eliminated in year 1 (a single event day in NSW could most likely be managed operationally through linepack) and year 2 exhibits single-digit event days at the end of winter.

Figure 14: Solving for 'y' – pipeline augmentation with 3PC pumped hydro



5.4 Timing of critical event days

Our final analysis tries to identify at what point the eastern gas market is likely to begin experiencing distress – noting that the current market operates in equilibrium throughout the year. We return to scenarios from Gilmore (2024) which assess gas market loading *during* the coal plant exit phase. Specifically, we run the numbers for 10GW of coal and 5GW of coal remaining in-service, in Figures 15 and16 respectively.

With 10GW of coal remaining in service (Figure 15), there is only a single event day in NSW >100TJ in each of years 1 and 2. These critical event days may be adequately resolved through better (dispatchable) plant scheduling, drawing on linepack, or both. Augmentation of pipelines from Wallumbilla through to Moomba (in anticipation of further coal exit) would most likely clear all imbalances.

Figure 15: 10GW of coal-fired generation plant in service

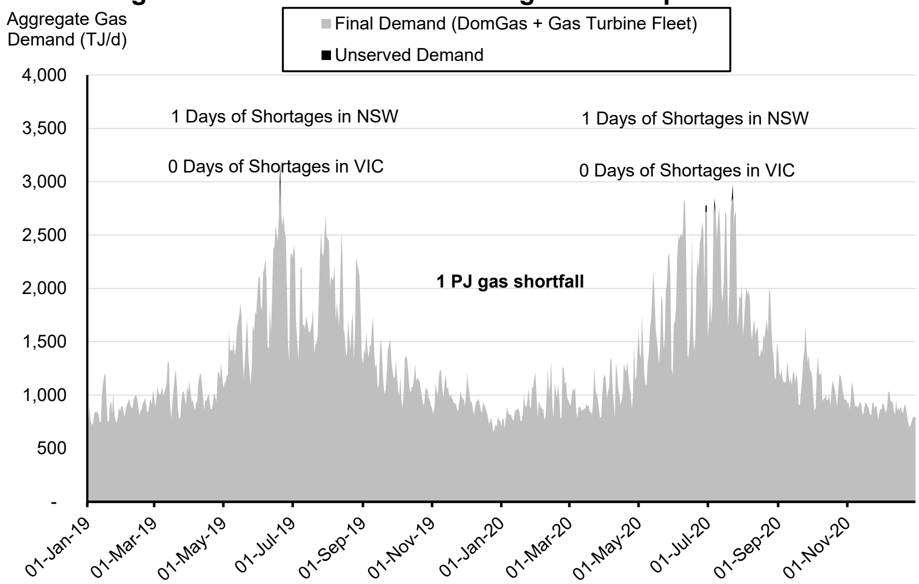
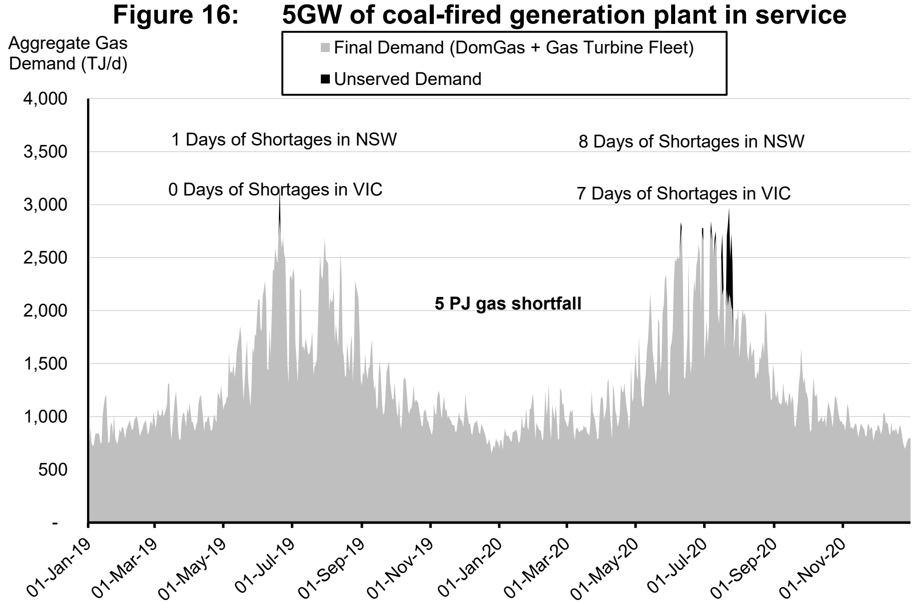


Figure 16 shows that with 5GW of coal remaining, there is a modest rise in critical event days in the second year, largely due to storages being exhausted before the end of winter and pipeline congestion consistent with that in Figure 13, albeit with less intensity. This suggests gas market problems may begin to amplify with less than 5GW of coal plant in service.

Figure 16: 5GW of coal-fired generation plant in service



6. Policy implications

The potential for episodic, unmitigated demand shocks from the NEM's emergent gas turbine fleet is not in anyone's best interests. Gas prices would be pushed higher, infrastructure capacity necessarily increases but utilisation rates may fall, and in worst-case scenarios, security of supply would be tested and likely breached in the markets for gas and electricity, simultaneously. In our modelling, LNG plants bear disruption costs (acknowledging the political economy of a reliability event), but ultimately, consumers pay. So what are the key observations and policy implications arising from our research? We would suggest the following:

- At the outset we should note that, axiomatically in the long run, the operation of gas turbines fired on natural gas is inconsistent with a policy of net zero emissions. Conversely, gas turbines operating on hydrogen and associated derivatives is. Gilmore, Nelson and Nolan (2023) show that even at high fuel cost ($50/GJ), gas turbines are still critical to maintain supply reliability given our current understanding of intermittent renewables and storage costs (see also Mountain, 2024).

- However, those alternate fuels are not readily available now, and neither is the market necessarily readily able to adjust rapidly even if they were. Energy markets need to *transition to renewables*, not collapse due to poor structural adjustment planning. It is generally accepted in Australia's NEM that coal plant exit requires an orderly transition across an array of dimensions including costs, prices, CO_2 emission objectives, reliability of supply and workforce-related policy parameters. Natural gas is an important fuel that currently provides a crucial 'shock absorber' to NEM coal plant exits, given the inherent intermittency of renewables.

- All forecasts by all modellers in our dataset exhibited material dispatchable firming duties for the NEM's emergent gas turbine fleet following exit of the coal plant, with a notable intensity during the winter months of June and July. This aligns with well-documented winter season depressions in NEM renewable energy output due to lower solar irradiation and east coast wind speeds.

- Therefore as an absolute general conclusion, energy policy in Australia needs to originate initiatives that work towards solving these challenges, not grind against them. Mountain (2024) illustrates in some detail using South Australian data comprising very high renewables and storage (i.e. a largely successful power system transition) that the final few percentage points of market share and operating duties undertaken by the gas turbine fleet will be particularly costly to displace, at least given our current understanding of storage costs and elasticity of demand.

- Detailed power system modelling (time-sequential, 30-minute resolution), and our results in Section 5 indicate short duration batteries and gas turbines alone may not be able to manage the firming task (Gilmore, 2024).

- When we constrained pumped hydro plant developments to 'zero additional capacity commitments', conditions in our gas market model deteriorated very materially. We found gas demand shocks were amplified during winter, the extent of which proved *highly problematic* for our model of the east coast gas market. Adding intermediate duration pumped hydro plant to replace some component of the firming/storage task currently undertaken by coal plant (and their storage capacity, viz 'coal stockpiles') seems to be a policy imperative. Evidently, the energy density of pumped hydro and its ability to move renewables (and solar in particular) through time has its own value vis-à-vis avoiding problems in the adjacent market for natural gas.

- Diversifying the firming task across a fleet of low-cost batteries, pumped hydro and gas turbines improved conditions considerably. Yet gas turbine duties still placed residual pressure on the market for natural gas at certain times.

- Certain gas pipelines placed critical constraints on gas turbine operations during critical events in NSW and Victoria. Our model does not deal with gas pipeline 'linepack' (i.e. gas stored and available for use in pipelines) and this is to be acknowledged as an important modelling limitation. Prima facie, this limitation suggests we may have *overstated* the extent of the problem to be solved.

- On the other hand, our reported results *'set aside'* all unserved load events below 100TJ/d, to recognise that linepack may be available. Furthermore, our model did not examine the frequency of Maximum Hourly Quantity (MHQ) events. We focused only on Maximum Daily Quantities (MDQ). As it turns out, the frequency of critical MHQ events occurs at ~19x the rate of MDQ events (see analysis in Figure A-3, Appendix I). This suggests we may have dramatically *understated* the problem to be solved.

- In this context, no regrets policy solutions might commence with additional storages, storable fuels and fuel sources ideally located closer to the problem epicentre – Sydney and Melbourne. This may come in an array of formats including new gas storages, additional linepack, liquid (diesel) fuels and a requirement for all new gas turbines to be commissioned as 'dual fuel' plant.

- All new gas turbines should ideally have the potential to operate on both natural gas and liquids, and be adjustable to hydrogen and hydrogen derivatives such as ammonia in line with the long run objective of energy policy – and particularly given the ability to store the latter.

- We set to one side the matter of declining gas field production in Victoria as outlined in the Market Operator's latest report. Lower gas field production – especially during the winter months of June and July in southern Australia – will amplify risks of critical event days absent material pipeline augmentation. Yet it is not immediately obvious through our model or inspection of Table 3 that augmentation is viable either, noting the shortest pipeline pathway from Wallumbilla to Sydney is 2200km, and further again for Melbourne. This suggest having fuel supplies closer to loads will be important throughout the transition period.

- Nonetheless, pipelines which may warrant further investigation for incremental compression or capacity augmentation appear to be those associated with transferring gas along the Wallumbilla to Sydney flow path. Doing so may facilitate shipping Queensland gas to southern markets during critical events. And alleviating NSW critical event days should assist Victoria, noting a 96% crossover between Victoria and NSW. However as noted at the outset, in the long run, gas turbines fired on natural gas is inconsistent with a policy of net zero emissions and cost recovery periods would therefore need to be examined.

- Given the high value of gas turbines vis-à-vis firming duties, demand-side reductions in other sectors and across both fuels may help alleviate constraints and direct limited supplies (and corresponding emissions) to highest value uses. Conversely, electrification of existing gas consumption necessarily increases electricity demand. The correlation between electricity and DomGas consumption therefore requires careful investigation to ensure the problem we have identified is being remediated, not amplified, in the short run.

7. Concluding remarks

Structural adjustment of the NEM's supply-side involves the progressive exit of 30GW of coal-fired power stations, a process which commenced from 2012. Continuous entry of intermittent renewables (via shareholder and supply chain pressures) are driving coal exit, but reliability of supply requires that its capacity be replaced by a fleet of dispatchable assets, specifically, short duration batteries, intermediate duration pumped hydro and fuel based turbines as the last line of defence or *'capacity of last resort'*. Firming assets compete against each other at the margins but, to be clear, it is broadly accepted that no single generation technology can cost effectively mitigate intermittency, maintain grid stability and ensure security of supply (Javed et al., 2020; Gilmore et al., 2023; Simshauser and Gohdes, 2024). In other words, a portfolio is required.

We collated a series of market forecasts by market modellers with a special interest of the role played by gas turbines as the *capacity of last resort* in the latter- and final-stages of coal plant exit. We found episodic surges in gas turbine activity during winter months when renewable output experiences cyclical lows. When we tested gas turbine 'demand shocks' in a dynamic partial equilibrium model of Australia's eastern gas market, we found the potential for unserved demand on critical event winter days. The problem was most prominent in NSW, with events occurring simultaneously in Victoria as well.

Our model and associated scenarios revealed a series of markers and guardrails. First, LNG exports, given our gas supply-side and demand-side assumptions, were not a cause of the problem per se. In the model, LNG plant diverted feedstock to the domestic market at the first sign of trouble. Second, any under-investment in pumped hydro plant will be problematic and amplify the frequency and intensity of gas market critical event days. Third, pipeline augmentation is capable of reducing Unserved Demand events and we expect this would be of significant interest to policymakers given the gravity of the implications of the problem – noting the distances involved are very long and therefore far from costless, and there is a risk of stranded assets as the economy is decarbonised. Detailed analysis of demand side reductions and the impact of electrification was not considered in this study.

Additionally, model results tend to suggest that as the remaining coal generation fleet falls below 5GW, problems are more likely to intensify. Batteries and pumped hydro are highly beneficial but not a complete solution at this time. This suggests gas storage and other forms of stored fuels will become important in time.

As with all complex problems, resolution of the problem we have identified requires an array of policy responses and investment initiatives. The timeframes involved should be tractable, albeit with an important caveat of 'given our base demand and supply assumptions'. The Market Operator's most recent reports appear to cast doubt over the latter, suggesting some initiatives may be more urgent than others.

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APPENDIX I

Figure A-1: Gas Storage Balances – no pumped hydro scenario

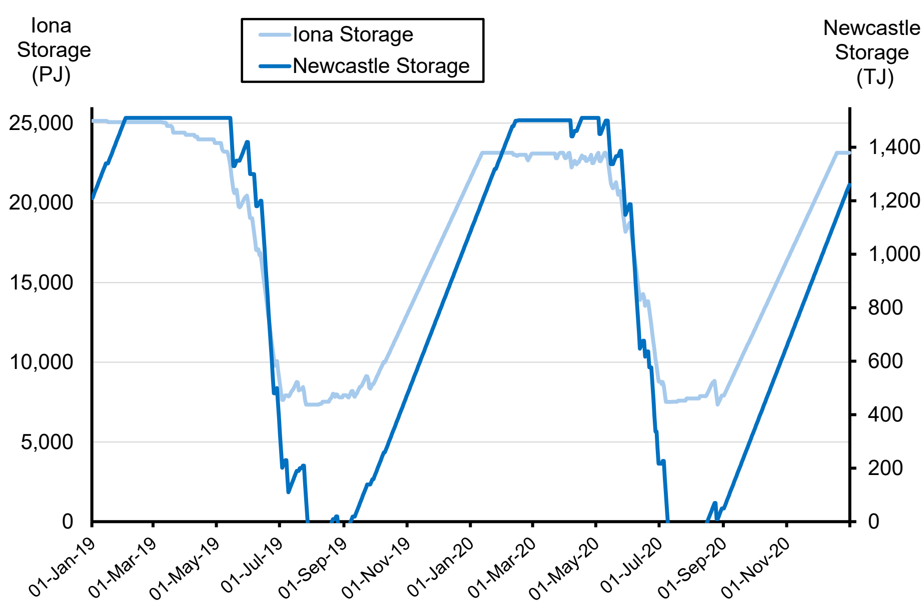

Figure A-2: Gas Storage Balances – adjusted pipeline scenario (vs no pumped hydro)

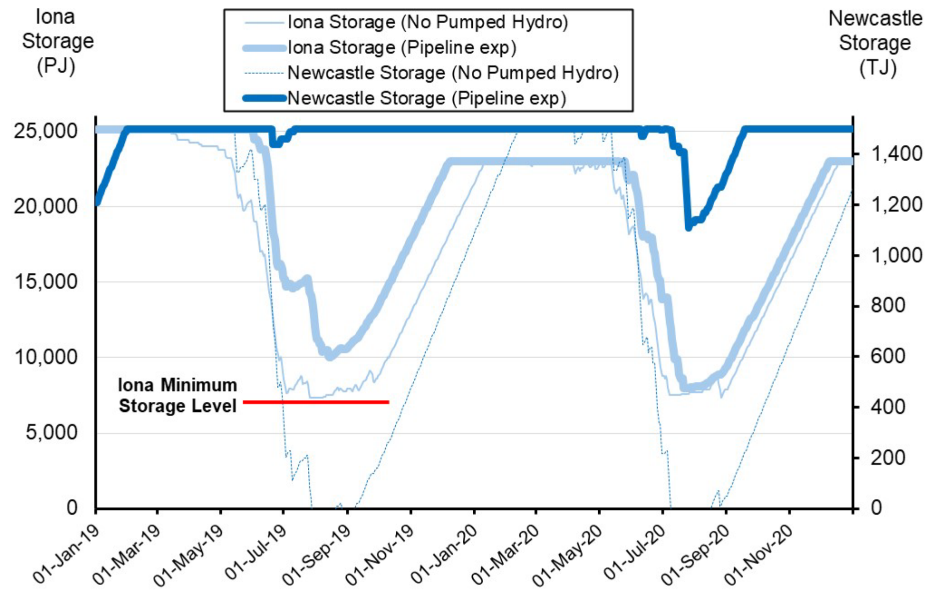

Figure A-3: NSW Gas Load Duration Curve: Daily vs Normalised Hourly Max. Quantity