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Policy sequencing: on the electrification of gas loads in Australia's National Electricity Market

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Decarbonising our power systems requires coal plant to exit and be replaced by intermittent renewables, along with a diversified fleet of flexible firming plant (viz. batteries, pumped hydro, gas turbines). It also requires electrification of the gas market. In Australia's National Electricity Market, certain jurisdictions have sought to pursue power system decarbonisation and electrification of gas loads simultaneously. Using 40 years of weather re-analysis data in parallel electricity and gas market models, we identify the generation plant investment task required to meet the primal energy policy task of minimising cost, subject to reliability and CO_2 emissions constraints. The outstanding renewable investment task is very material, and accelerating electrification may have the unintended effect of entrenching coal plant for longer. Further, a large fleet of gas turbines is required to deal with intermittency during winter months when renewables experience annual output nadirs. Yet a larger gas turbine fleet produces an acute peak (gas) demand problem during critical event winter days. Electrification of gas customers reduces annual gas demand, but ironically, gas turbine output on those critical event days means there is little change in daily maximum gas demand. This is quite a paradox – electrification policy signals the structural decline of gas networks, yet gas turbines and supporting gas storage and pipeline infrastructure become critical to maintain security of supply. Careful investment planning and policy sequencing is therefore required.

Keywords electrification, renewables, natural gas, energy-only markets, dispatchable plant capacity.

JEL Classification D52, D53, G12, L94 and Q40.

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Introduction

For most of the 20th century, the objective function of power system planning was to minimise costs subject to a reliability constraint. The optimal mix of plant could be readily defined courtesy of the static partial equilibrium frameworks developed by Boiteux (1949), Turvey (1964) and Berrie (1967). This framework made the asset allocation task in large thermal power systems tractable via optimising the rich blend of fixed and variable costs of base, intermediate and peaking plant against an inelastic aggregate demand function. An appropriate reserve plant margin ensured reliability constraints would be met, the basis of which was first set out in Calabrese (1947). Dynamic, security-constrained unit commitment models would soon follow via the efficiency of the Booth (1972) method and associated temporal statistical aggregation techniques.

In the decarbonisation era, the power system objective function is altered to incorporate a CO_2 emissions constraint. At this point, optimal asset allocation in large thermal power systems changes with the introduction of intermittent renewables. To generalise, up to ~20%

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intermittent renewable market share presents no material issues for power system planning other than cost (Simshauser and Newbery, 2024). Berrie's (1967) static partial equilibrium framework can be readily adjusted by using net load duration curves – a technique which dates at least as far back as Martin and Diesendorf (1983).

Moving beyond ~20% market share, renewable costs fall with learning effects and scale deployment, but technical challenges rise in complexity. These challenges include the progressive loss of inertia (Newbery, 2021), emergent system strength shortfalls (Badrzadeh et al., 2020; Qays et al., 2023), sharply falling minimum loads (Simshauser and Wild, 2025) and the disorderly loss of legacy coal plant (Dodd and Nelson, 2019; Rai and Nelson, 2021). The entry of new flexible firming plant and storage capacity (at scale) become crucial to managing intermittency (Billimoria and Poudineh, 2019; Gilmore et al., 2023). From 20+% renewable market share, the use of multiple weather years and *chronology* becomes essential. In short, temporal aggregation methods and static models become inadequate for the planning task (see Guerra et al. 2020; Merrick et al., 2024).

Adding to power system planning complexity is how electrification of gas loads will impact the market. In Australia's National Electricity Market (NEM), two jurisdictions – Victoria and the Australian Capital Territory – are simultaneously pursuing the dual tasks of decarbonising the power system *and* electrifying the domestic gas market (Hammerle and Burke, 2022). Of these, Victoria[1] presents as an interesting case study on the role of policy sequencing due to the size and prominence of its gas market.

Victoria developed a gas substitution or *electrification policy* during 2021-2022[2] which focused on end-of-life gas appliances in rental homes (25% of housing stock), banning new gas connections to the new housing stock and a requirement that all new government facilities are all-electric. If electrification of the gas market over the next decade is the objective, *prima facie*, these initiatives present as necessary first steps. But while Victoria has made considerable progress with respect to renewables (c.40.5% market share) brown coal persists with 65% market share (including exports). If renewable developments fail to keep pace, adding electrification loads to the power system will either raise power prices above tolerable thresholds, entrench coal plant longer than necessary, or both.

The purpose of this article is to examine the implications of simultaneously pursuing power system decarbonisation and gas market electrification under imperfect market conditions. Our scenario focuses on substantial (75%) electrification of the residential consumer segment and modest (20%) electrification of the industrial sector across the NEM. Using a suite of time-sequential electricity and gas market load and unit commitment models with 40 years of demand and renewable generation derived from historical weather re-analysis data (hourly resolution), we identify the least-cost generation plant stock required to maintain the power system in a secure state following the closure of Australia's coal-fired generation fleet. We also test these outcomes in a gas market model.

Model results suggest sequencing of electricity system decarbonisation, and electrification of the gas market, is important. Electrification of the gas market drives non-trivial increases in aggregate final electricity demand during winter periods. This happens to coincide with the period when renewable output hits its annual nadir.

If power system decarbonisation stalls due to renewable development constraints or entry delays, electrification of the gas market necessitates greater reliance on remnant coal plant

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[1] The Australian Capital Territory forms a trivial subset of the NEM's largest zone of New South Wales. Consequently, security of supply (at the bulk supply level) in the ACT is driven almost entirely by the policies of the New South Wales region.
[2] For details see [Victoria's Gas Substitution Roadmap (energy.vic.gov.au)]

in maintaining reliable supplies, and thus works *against* the decarbonisation objective. The main point is that there may be unintended consequences of pursuing electrification of the gas market ahead of substantial power system decarbonisation if the latter is stalling. Further, if the power system is underweight dispatchable (firming) plant capacity, electricity prices are likely to rise and become unstable. The political economy of end-user electricity tariffs means both decarbonisation *and* electrification policies may then become unstable – a phenomenon which Australia has become all too familiar with. Modelling suggests *"policy sequencing"* is therefore extremely important.

This article is structured as follows. Section 2 provides a brief review of literature. Section 3 introduces our modelling suite. Section 4 examines model results. Policy implications and concluding remarks follow.

Review of literature: climate policy discontinuity

Our literature review seeks to identify lessons from history. Australia's climate policies have been unstable and characterised by discontinuity. Reasons for this relate to the political economy of electricity prices. There is strong evidence to suggest climate policy is a normal good (Dolphin et al., 2020), i.e. when electricity prices are stable there is "community-wide" support for decarbonisation policy. When electricity prices surge, support evaporates. Household surveys (including Australia[3]) note the community is *highly sensitive* to cost increases arising from carbon policies – and perhaps surprisingly – even where carbon price rebates reduce household impacts to negligible levels (Jenkins, 2014; Kockel *et al.*, 2024; Poruschi *et al.*, 2024). The Australian experience vis-à-vis the political economy of climate policy is consistent with this thesis (Simshauser & Tiernan, 2019; Nelson et al., 2022).

Climate policy architecture in electricity markets

Policy discontinuity and the absence of a united policy architecture linking energy and climate policy have been a feature of the NEM (Nelson, 2015; Nelson et al., 2019). The electricity industry is invariably a central player in any decarbonisation strategy with climate policy initiatives catalogued into five broad streams including Renewable Portfolio Standards, (Feldman and Levinson, 2023), Emissions Trading Schemes (Fankhauser et al., 2010), Feed-in Tariffs (Dodd and Nelson, 2022) and Energy Efficiency Schemes (Wirl, 2015; Rosenow and Bayer, 2017).

Policymakers typically deploy a combination of options (Pollitt and Anaya, 2016), although as Fankhauser et al., (2010) explain, only occasionally is this by design. More often, combinations are ad hoc, overlapping and driven by short term politics (cf. good policy). Policymaking in Australia has been dominated by this latter description. Consequently, few climate policies have exhibited real durability (see variously Jones, 2009; Garnaut, 2014; Nelson, 2015; Simshauser, 2018; Dodd and Nelson, 2019; Rai and Nelson, 2020). Two examples of such discontinuity were Australia's Renewable Energy Target and various approaches to emissions trading and carbon pricing.

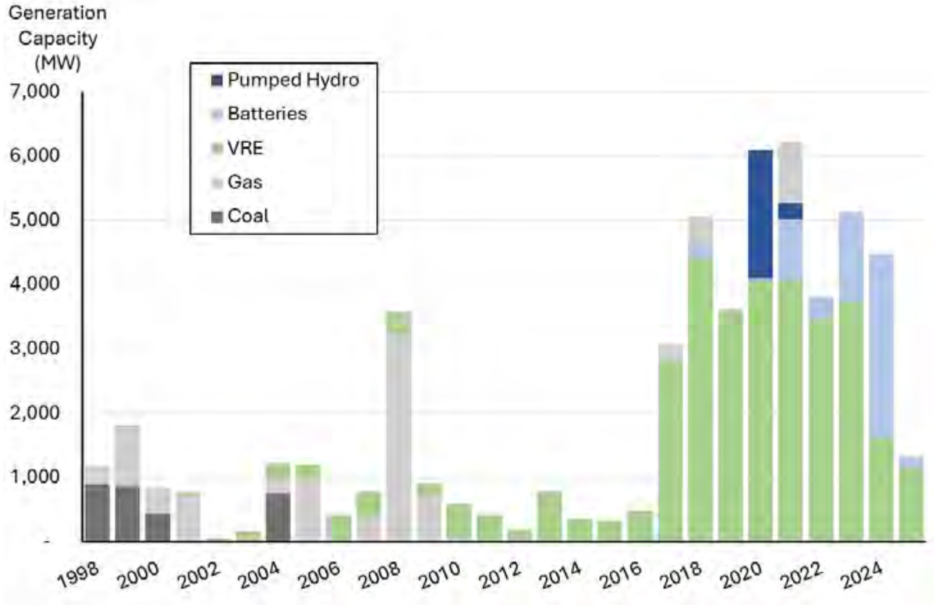
Discontinuity of Climate Policies in Australia

Australia's approach to climate policy commenced with the Renewable Energy Target or 'RET' – the world's first renewable portfolio standard, and several attempts at an emissions trading scheme. Both policies were first raised in parliament in 1997, but only the RET was legislated in 2000 – initially as a fixed volumetric policy of +10TWh by 2010 (Buckman and Diesendorf, 2010).

[3] See for example [Cost-of-living crisis means we can't afford to worry about our costliest threat (theage.com.au)]

Formal reviews of Australia's RET would occur on six separate occasions (2003, 2008, 2010, 2012, 2013 and 2015) with at least three fundamental changes to legislation (2008, 2012, 2015). Changes involved raising the target to 44TWh (2008), splitting the target between small- and large-scale schemes (2012), and reducing the target to 33TWh (2015) (see variously Jones, 2010; Byrnes et al., 2013; Forrest and MacGill, 2013; Nelson et al., 2013; Apergis and Lau, 2015; Nelson et al., 2022). Predictably, RET policy discontinuity led to investment stalling throughout 2011-2015, as Figure 1[4] illustrates:

NEM generation investment commitments Financial Close 1998-2024



Source: Simshauser and Gilmore (2022), Updates from Bloomberg New Energy Finance.

The RET's final amendment in 2015 was a bipartisan compromise aimed at clearing policy discontinuity and evidently instilled industry confidence based on the subsequent investment commitments (2017-2023). The 33TWh RET was technically met through cumulative investment commitments by 2018 (noting construction lags). Consequently, investments from 2018 onwards were driven largely by capital markets and supply chain pressures, with the entry cost of Australian renewables falling below the marginal cost of the thermal fleet for the first time. In short, industry was now leading, and policymaking was following.

The dataset underpinning Fig.1 reveals that from 2016-2024, \$83.1b across 223 projects totalling 35.4GW had reached financial close. This was split between \$54.8b across 173 wind and solar projects totalling 25.4GW, and \$28.3 billion of 'firming' projects (batteries, pumped hydro, gas turbines) across 50 sites totalling 10GW.

Placing a direct price on CO_2 emissions has been far more problematic. The first formal proposal for an Emissions Trading Scheme (ETS) emerged in the early 2000s, only to be discarded by the Prime Minister before legislation could be drafted (Jones, 2010). Sub-national government policies then sought to fill the void with schemes simultaneously arising in the NEM's two largest regions, Queensland and New South Wales (MacGill et al., 2006; Jones, 2009). Both schemes enjoyed early success (Daley and Edis, 2010), prompting a formal proposal for a "state-based" national scheme (Nelson *et al.*, 2010; Jones, 2014). This would ultimately lead to action by both sides of politics at the Commonwealth level for the

[4] Update to the database from Simshauser and Gilmore (2022) is current to September 2024 with additions being drawn from Bloomberg New Energy Finance. Data is presented on a Financial Year basis, 1 July to 30 June.

2007 election (Jones, 2010). After 10 years of discontinuity, carbon pricing appeared to be bi-partisan policy (Garnaut, 2014).

During 2008, legislation for an ETS was drawn up (Buckman & Diesendorf, 2010). A change in conservative party leadership in late-2009, grounded in an anti-carbon tax narrative (Garnaut, 2014), and the generalised political economy of carbon prices led to the government "pulling" its legislative agenda.

This carbon price legislation would not be revived until 2011, and was implemented in 2012 (Jones, 2014). Consistent with the literature (see Fankhauser et al., 2010), despite extensive tax recycling to households, trade-exposed industries and coal-fired generators, price impacts of the ETS breached a political economy constraint and became the central feature of the 2013 Commonwealth election (Crowley, 2017). The incoming conservative party dismantled the policy almost immediately, with the price on carbon removed during 2014 (Simshauser, 2018).

The Commonwealth Government subsequently committed to a climate change policy review through its Climate Change Authority, to be completed during 2017 with the 2030 emissions target in mind (Simshauser and Tiernan, 2019). The Authority recommended, and NEM sub-national governments supported, an Emissions Intensity Scheme to be applied to the electricity sector only (Bell et al., 2017; Rai and Nelson, 2020). Yet within hours of its being announced, a backbench revolt of the conservative government led to the policy being discarded before an inquiry had even started (Crowley, 2021).

In early 2017, a subsequent government-commissioned review by Australia's then Chief Scientist recommended a *Clean Energy Target*, and it too had been discarded by the end of that year (Simshauser, 2018; Crowley, 2021) and by largely the same group of backbench politicians. A final attempt emerged in late 2017, the 8^{th} of 8 attempts at setting a price on carbon, a dual mechanism involving a reliability obligation and an emissions reduction obligation known as the National Energy Guarantee (Simshauser and Tiernan, 2019). It was once again widely supported amongst NEM sub-national governments, but as with its predecessor policies, was discarded in 2018 before it could be implemented (Crowley, 2021). As an aside, carbon policy discontinuity has been associated with the removal of at least 4 Australian Prime Ministers (Crowley, 2017, 2021; Simshauser and Tiernan, 2019).

Summary

So what are Australia's climate policy lessons from history?

1. As Poruschi et al. (2024) note, the political economy of climate policy means limited tolerances exist for consequential electricity tariff increases even in the presence of extensive recycling of climate-related taxation revenues (Jenkins, 2014). Partisan politics in Australia is an important variable (Jones, 2014; Crowley, 2017, 2021).

2. When any climate policy is successfully adopted and applied to the electricity industry, durability hinges on (end-use) electricity price stability. Alternatively put, Australian policymakers seeking to expand climate policies must be mindful of electricity price instability.

3. Policy discontinuity can be expected to create discontinuous investment (Rai and Nelson, 2020), raise the cost of capital (Rai and Nelson, 2021), and raise wholesale electricity prices above the minimum obtainable.

With this backdrop, our attention now turns to decarbonisation and electrification in the context of price stability, and a goal of policy continuity. In doing so, our modelling efforts turn to the inter-annual variability of renewables and its implications for policy sequencing. This variability has been well articulated in the European context (see Charitopoulos et al., 2023; Ah-Voun *et al.*, 2024; Chyong et al., 2024) and the US (see (Guerra et al., 2020; Merrick et al., 2024) but is less so in Australia.

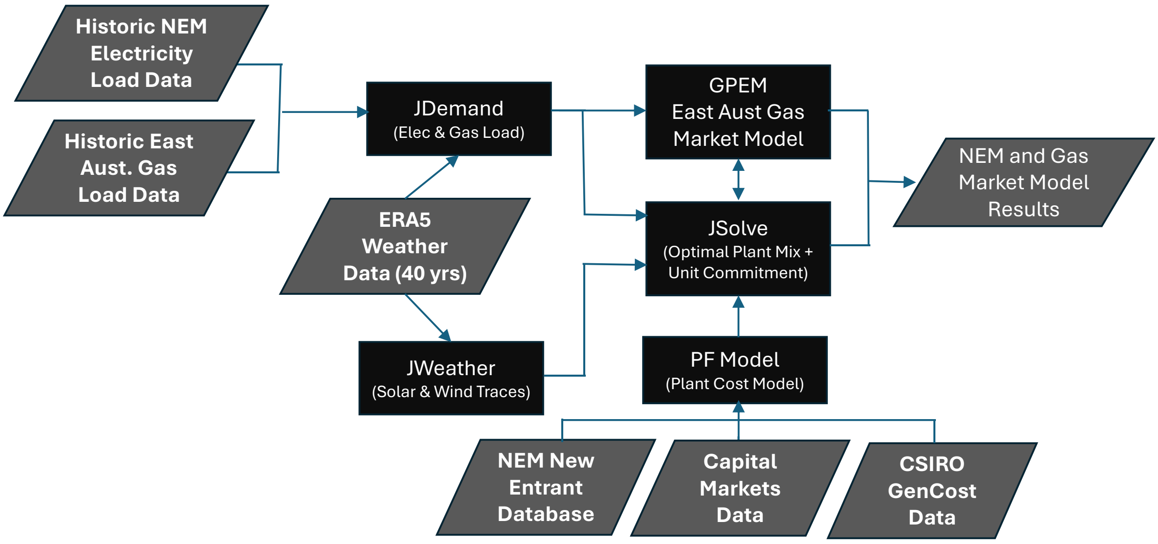
Models and Data

Our analysis involves a significant modelling task including a suite of dynamic, interconnected structural models and representative weather data. Collectively this enables us to establish suitable weather-corrected, time-sequential forecasts of aggregate final demand for electricity and gas, translation of gas market electrification, and a suitable portfolio of geographically diverse wind and solar resources.

Historically when modelling a large thermal power system, it would be adequate to identify two load curves (PoE50 and PoE10 weather conditions). In a largely intermittent renewables power system, both demand and large parts of the aggregate supply function are tied to weather variations. In our view, the gold standard for such a task is to utilise weather reanalysis data, which enables 40+ years of historic weather data (by location, at hourly resolution) to be utilised.

We make use of our dynamic partial equilibrium (security-constrained, unit commitment) models of the electricity market, and the gas market, for the purposes of identifying investment and decommissioning tasks. Our modelling framework is set out in Fig.2:

Decarbonisation and Electrification Modelling Framework



Given the uncertainty over the timing of decarbonisation trajectories, electrification rates and capital cost reductions, we consider a snapshot of assumptions of a future substantially decarbonised grid in the latter half of the 2030s, which we outline below along with a description of the models.

JDemand – Forecasting Aggregate Final Electricity and Gas Demand

In Fig.2 our first model is 'JDemand' – its purpose is to produce forecasts of aggregate final electricity and gas demand on a weather-adjusted basis (hence the link to 'ERA5' weather data). These demand forecasts form foundational inputs to our electricity and gas market models.

Structurally, JDemand is classed as a *random forest walk* machine learning model. It trains on historical NEM electricity[5] and gas market data[6], suitably matched to Australian calibrated *ERA5* weather re-analysis data (Copernicus Climate Change Service, 2023; Hersbach et al., 2023). Once trained, JDemand outputs provide a representative (hourly) demand time series for electricity, and for gas, at a NEM region level based on historical weather conditions (as per ERA5 data). With 40 years of historic weather data, we produce 40 demand traces for each region and each fuel (i.e. electricity and gas).

An *electrification module* within JDemand splits gas demand into two sectors (residential and industrial) and converts these to electrical loads. Assumptions on load shapes and the relative efficiency of electric water heating, electric heat pumps and reverse cycle air conditioners drive conversions at the residential level.[7]

JWeather: Forecasting hourly wind and solar output

The next model in Fig.2 is JWeather – the purpose of which is to generate usable utility-scale wind, utility-scale solar, and rooftop solar PV production functions at hourly resolution, time-stamped and matched to coincident aggregate final electricity demand.

This model also relies on ERA5 weather re-analysis (Hersbach et al., 2023) as a crucial input. JWeather internalises open-source software *pvlib* and *windpowerlb* to produce solar PV

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[5] Electricity load from AEMO. Data is publicly available at [AEMO | Nemweb data]

[6] Daily gas load from Energy Edge's GMAT. [Gas Market Analysis Tool | Energy Edge (gmat.com.au)] is EnergyEdge's proprietary software tool which stores, collates and analyses the East Australian gas network data, including pipeline flows, loads by node, gas field production and gas storage.

[7] In particular, space heating is modelled with a coefficient of performance linearised between 3.5 and 5.0 for zero to 20 degree Celsius operating temperatures, typical of modern energy-efficient reverse cycle air conditioners. Electric Vehicle and Consumer Energy Resources are incorporated with profiles based on data produced by Australia's principal research organisation, the CSIRO. See [CSIRO report template (aemo.com.au)]

and wind generation traces. Representative sites have been aggregated by region to deliver 40 annual wind and solar traces for each NEM region with hourly resolution.

Australia has by far the highest rooftop solar PV take-up rate in the world. Consequently, it is an important resource with NEM-wide rooftop capacity currently ~20GW (cf. maximum system demand of 38GW). As with Australian Energy Market Operator, we assume rooftop solar PV plant capacity continues to expand rapidly to 45GW over the long run. For our purposes, rooftop solar PV traces for ~100 population centres are aggregated into single region-wide traces and "netted off" against aggregate final demand.

PF Model

Our next model in Fig.2 is the PF (or 'Project and Corporate Finance') Model. The PF Model produces commercial-grade unit cost estimates of new entrant generation plant. While outputs present in a similar manner to Levelised Cost of Electricity Models, the PF Model produces unit costs/prices on a post-tax, post-financing basis. Project (or corporate) debt facilities and taxation rules are internalised and co-optimised, thus ensuring minimum technology costs[8] are identified. Model logic and critical inputs appear in Appendix I.

JSolve: Electricity Market Model

JSolve is a dynamic, time-sequential, partial equilibrium electricity market model that determines the optimal plant mix (given PF Model cost inputs) and simulates the mainland NEM states with hourly resolution. Tasmania is treated as an energy-limited hydro generator connected to the Victorian region of the NEM (see Fig.3).

At one level, JSolve presents as a standard multi-region, security-constrained, unit commitment and capacity expansion LP model. As with all such models, JSolve seeks identify the optimal plant mix and minimise generation dispatch costs, subject to reliability and emissions constraints. However, the novel contribution of JSolve beyond the standard modelling framework is the use of 40 years of historic weather conditions (hourly resolution) in each simulation run. Crucially, this approach captures the extreme variability of, and interactions between, wind output, solar output and weather adjusted aggregate final electricity demand, using 40 years of weather variation. Regional interconnectors constrain power flows between NEM regions (see Fig. 3) but within regions the model follows the copper-plate assumption (i.e. no intra-regional constraints).

National Electricity Market

[8] See CSIRO at [GenCost: cost of building Australia's future electricity needs - CSIRO]()

JSolve's primary purpose is to identify the optimal mix of generation plant investment and dispatch given available technologies, weather-dependant renewable resources, technology unit costs and prevailing aggregate final demand, and to produce daily gas-fired generation fuel requirements. Critically, with all weather-dependent inputs correlated to the same data set (ERA5), any correlations between residential gas use, electricity demand and wind and solar output (and thus gas-fired generation requirements are preserved. JSolve model logic appears in Appendix II.

GPEM: Gas Market Model

GPEM is a dynamic time-sequential partial equilibrium model of the East Australian gas market. As with JSolve, GPEM is a security-constrained LP model grounded firmly in welfare economics. The model assumes a highly competitive gas market and replicates all major gas fields, gas transmission pipelines and major storages – with the gas demand segments of residential and industrial loads, gas-fired generation, LNG imports and export defined discretely at a nodal level. GPEM logic and pipeline architecture appears in Appendix III, while a structural overview of the Model appears in Fig.4.

GPEM Model Structure (demand nodes, pipelines, fields, storage)

Model Results

We commence by presenting our model results for aggregate final gas demand, electricity demand, wind and solar output, power system investment and prices, and finally, gas market model results. Before proceeding, there are a number of parameters worth noting:

- We are seeking to identify the NEM plant mix in a post-coal plant era. We nominally consider this to be during the latter half of the 2030s, and accordingly this is the timeframe being modelled.
- To account for anticipated economic and population growth through to this period, we increase 2024 aggregate final electricity demand by 10% (before adding electrification loads).

- Conversely, our gas demand forecast experiences a 20% reduction from 2024 conditions (i.e. electrification).

- In all scenarios, the aggregate final demand for electricity and gas are modelled as strictly decreasing and linear functions with own-price elasticities of −0.10 and –0.18, respectively (see Burke and Abayasekara, 2018; Sergici et al., 2020 and Li et al., 2022). Our models iterate so that if the price of either electricity or gas increases sharply, demand adjusts downwards, and vice versa, through sequential model iterations.

Forecast for aggregate final gas demand

Natural gas is an important fuel for household heating and industrial processing in the southern parts of Australia's NEM, and Victoria in particular. Conversely, in the northern parts of the NEM (i.e. Queensland), more than 85% of households are all-electric due to the tropical climate, mild winters and dominance of reverse cycle air-conditioners.

By comparison to other markets such as Great Britain, Europe and North America, natural gas and gas-fired generation has played a crucial but comparatively minor role in Australia's NEM. That is, gas-fired generation has been largely constrained to peaking duties due Australia's very low cost coal-fired fleet, policy failures to implement an ETS, and the emergence of an LNG export industry.

Development of the LNG export industry in Queensland followed discoveries of very large reserves of coal seam gas during the 1990s-2000s. The LNG export industry had the effect of linking the east Australian domestic gas market to (higher) seaborne prices (Simshauser and Nelson, 2015; Grafton et al., 2018). One implication is that the NEM effectively jumped from coal to renewables. Gas has not played a bridging role in the same way it has in other jurisdictions. Indeed, gas-fired generation is expected to continue to function largely as a peaking (firming) fuel. And there has been no material change between historic or forecast annual gas use in Australia's NEM (see Simshauser & Gilmore, 2024).

The practical outcome of this is that the east Australian domestic gas market has *comparatively thin* power generation loads. Gas infrastructure has been sized to serve mainly residential and industrial demand, and may not be compatible with the power system firming task ahead.

Tab.1 presents current East Australian annual gas demand in petajoules per annum (PJ/a), and Maximum Demand in terajoules per day (TJ/d) by NEM region. Note Aggregate Final Domestic Demand is 575PJ/a (Line 3) whereas LNG exports are 1328PJ/a (Line 4). Electricity generation, at 108PJ/a (Line 1) represents only 6% of the east Australian gas market. Maximum Domestic Demand of 2854 TJ/d (Line 8) is dominated by the DomGas segment, with the electricity generation demand of 988TJ/d *not* being coincident (i.e. maximum demands have not historically been *additive*).

Current East Australian Aggregate Final Demand for Natural Gas

	Gas Demand (PJ/a)	QLD	NSW	VIC	SA	TAS	NEM
1	Electricity Generation	17	16	21	52	3	109
2	DomGas (Resi, C&I)	99	132	201	36	6	474
3	Aggregate Domestic Demand	116	148	222	88	10	583
4	LNG	1,357	-	-	-	-	1,357
5	Aggregate Final Demand	1,472	148	222	88	10	1,940
	Maximum Demand (TJ/d)	QLD	NSW	VIC	SA	TAS	NEM
6	Electricity Generation	88	301	447	393	96	988
7	DomGas (Resi, C&I)	309	899	1,206	155	22	2,302
8	Max. Domestic Demand	378	1,192	1,356	495	110	2,854
9	LNG	4,314	-	-	-	-	4,341
10	Max. Final Demand	4,692	1,192	1,356	495	110	6,375

Source: EnergyEdge GMAT.

Tab.2 presents our forecasts for aggregate final gas demand (Lines 1-10) and maximum gas demand (Lines 11-18) for our *Decarbonisation Scenario* and our *Decarb.+ Electrification Scenario*. Recall we assume electrification involves 75% of the residential gas and 20% of the industrial gas market converting from gas to electric drives.

JDemand Forecast of Aggregate Final Gas Demand by Region (late-2030s)

	NEM Region	Existing NEM Energy Demand (PJ/a)	Decarbonisation Energy Demand (PJ/a)	Decarb. + Electrific. Energy Demand (PJ/a)	Chg Energy Demand (PJ/a)	Chg Energy Demand (%)
		a	b	c	(c - a)	(c - a) / a
1	QLD	115.5	128.9	114.2	-1.3	-1%
2	NSW	148.5	149.8	111.0	-37.5	-25%
3	VIC	221.6	257.0	196.2	-25.4	-11%
4	SA	87.9	49.1	36.5	-51.4	-58%
5	TAS	9.6	8.4	8.4	-1.2	-13%
6	Total	**583.2**	**593.2**	**466.4**	**-116.8**	**-20%**
7	*DomGas*	*474.0*	*398.5*	*217.7*	*-256.3*	*-54%*
8	*Gas Turbines*	*109.2*	*194.6*	*248.7*	*139.5*	*128%*
9	QLD LNG	1357	1349.0	1349.8	-7.0	-1%
10	Total	1940	1942.2	1816.2	-124	-6%
	NEM Region	Existing NEM Max Demand (TJ/d)	Decarbonisation Max Demand (TJ/d)	Decarb. + Electrific. Max Demand (TJ/d)	Chg Max Demand (TJ/d)	Chg Max Demand (%)
11	QLD	378	957	932	554	146%
12	NSW	1,192	1,192	1,090	-102	-9%
13	VIC	1,356	1,785	1,823	467	34%
14	SA	495	681	652	157	32%
15	TAS	110	48	48	-62	-57%
16	Total	**2,854**	**4,424**	**4,417**	**1,563**	**55%**
17	*DomGas*	2,302	1,800	791	-1,511	-66%
18	*Gas Turbines*	988	2,790	3,673	2,684	272%
17	QLD LNG	4,341	4,411	4,419	78.0	2%
18	Total	6,375	7,810	7,812	1438	23%

There is a critically important set of results in Tab.2 – highlighted by the **bold** numbers. Note at Line 6 Column 'a' that existing domestic gas demand is 583.2PJ/a, and that this declines to 466.4 under our electrification scenario (Column 'c'), a decrease of -20%. However, maximum gas demand (Line 16) is forecast to increase by 55%, from 2854 TJ/d to 4417 TJ/d – driven largely by Gas Turbines (see Line 18).

Aggregate final electricity demand

Of central importance to the present exercise is our underlying forecasts for aggregate final electricity demand in our *Decarbonisation Scenario*, and *Decarb.+Electrification Scenario*. Our headline results from JDemand are illustrated in Tab.3. For clarity, energy demand figures are 'native demand' (i.e. aggregate final energy demand which includes self-consumed rooftop solar) while maximum demand results are *'grid-supplied loads'* – meaning rooftop solar PV and behind the meter Consumer Energy Resources (i.e., consumer controlled electric vehicles and embedded batteries) have been netted-off.

JDemand Forecast of Aggregate Final Elec Demand by Region (late-2030s)

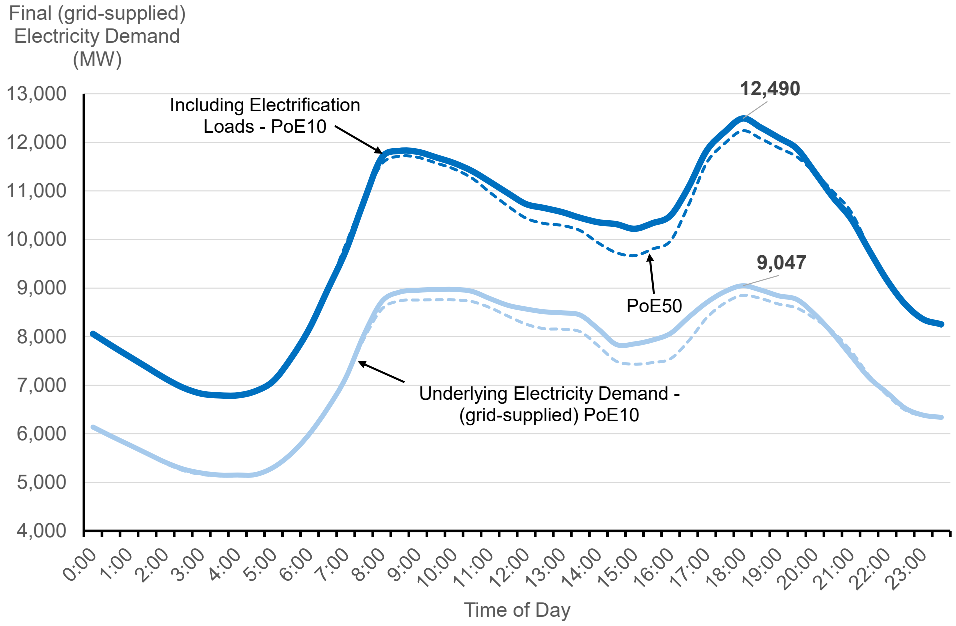
	NEM Region	Existing NEM Energy Demand (GWh)	Decarbonisation Energy Demand (GWh)	Decarb. + Electric. Energy Demand (GWh)	Chg Energy Demand (GWh)	Chg Energy Demand (%)
		a	b	c	(c - a)	(c - a) / a
1	QLD	63.0	68.2	72.4	9.4	15%
2	NSW	75.0	85.8	92.3	17.3	23%
3	VIC	48.3	59.0	70.4	22.1	46%
4	SA	14.6	18.3	20.2	5.6	38%
5	TAS	10.6	10.6	10.6	0.0	0%
6	NEM	211.5	241.9	265.9	54.4	26%
	NEM Region	Existing NEM Max Demand (MW)	Decarbonisation Max Demand (MW)	Decarb. + Electric. Max Demand (MW)	Chg Max Demand (MW)	Chg Max Demand (%)
7	QLD	11,005	11,971	13,286	2,281	19%
8	NSW	13,715	15,020	16,584	2,869	19%
9	VIC*	9,507	11,050	13,999	4,492	41%
10	SA	3,102	3,709	4,039	937	25%
11	TAS	1,884	1,884	1,884	0	0%
12	NEM	38,638	42,994	49,062	10,424	24%
	*Maxiumum demand changes from summer to winter					

Through inspection of Tab.3, it can be seen that profound effects arise from electrification policy in Victoria, with final energy demand rising by 46% (Line 3) and maximum demand by 41% (line 9). The reason for this is the coincidence of electricity and gas heating loads during Victoria's winter months. It is for this reason that much of our following analysis tends to focus on Victoria.

In Fig.5, we attempt to provide some sense of the significant impact of partial gas market electrification by analysing the change in aggregate final (grid-supplied) electricity demand on 'critical event winter days' – that is, the average of the top 12 winter days before, and after, partial electrification. For this purpose, we have isolated PoE10 weather years – consistent with power system planning practices[9]. To summarise results, the (average maximum) demand during the top 12 Victorian PoE10 critical event maximum winter days increases from about 9,000MW to ~12,500MW (and ~450 GWh per day) – noting that the single event maximum demand is 13,999MW as outlined in Table 3. In Fig.5, the average of PoE50 years are also illustrated.

[9] This averaging process means individual critical event days invariably exhibit materially higher hourly maximum demands (MW).

Victorian winter- aggregate final electricity demand (late-2030s)



JWeather: 40 weather-years of wind, solar and energy demand

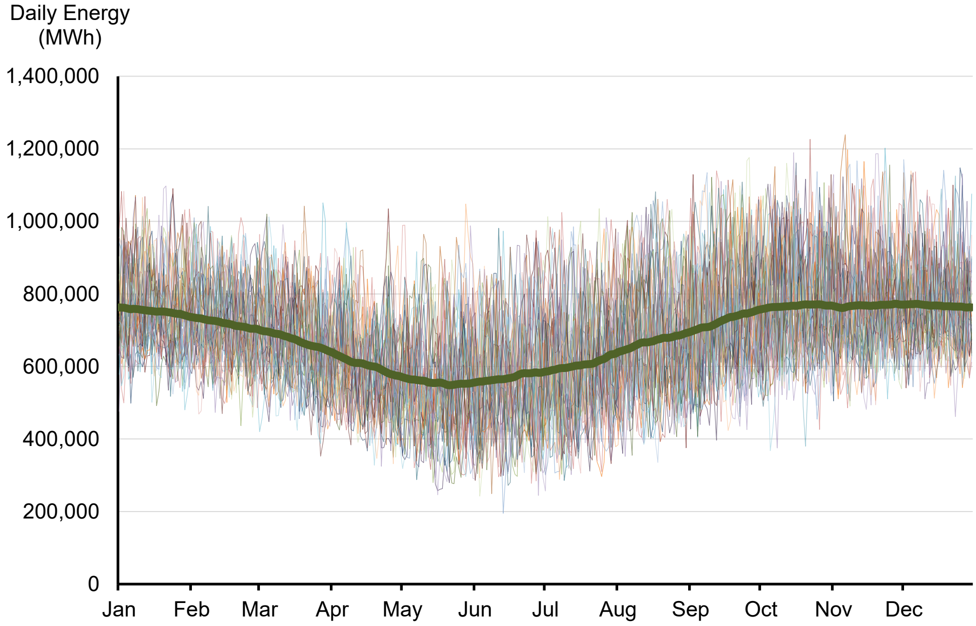
The level of variability in wind and solar production, and in electricity demand, needs to be examined as a coincident problem over an extensive array of historical weather years as we move to a renewables-intensive power system. With a large thermal fleet, understanding the true diversity of weather is not as crucial. Coal and gas plant – with a suitable reserve plant margin – can be expected to maintain a reliable supply under PoE10 conditions because the availability of the supply-side plant has no material relationship with weather other than forecastable thermal plant de-ratings.

A large renewable fleet imports a new dimension of power system planning risk tolerances because both final demand (after rooftop PV) – and large parts of the aggregate supply function – are sensitive to weather conditions. For this reason, it is necessary to ensure a suitably assembled, time-stamped and time-sequential forecast of plausible weather scenarios impacting coincident wind production, solar production, and aggregate final demand are established within the power system model. This process is, in our opinion, crucial and represents a relatively new frontier. As noted earlier, we deploy 40 years of hourly weather data to determine wind and solar output and aggregate final demand. The high-level output from the optimised and least cost mix of wind and solar (determined via JSolve) is presented for the NEM in Fig.6, and for Victoria in Fig.7.

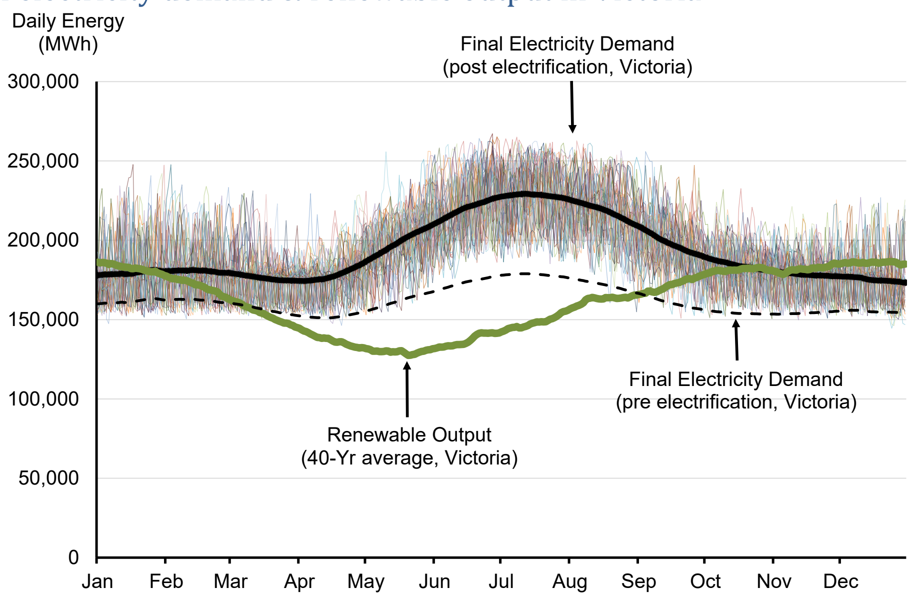
Figs.6-7 accumulate hourly renewable and aggregate electricity demand data into daily (and 30-day moving average) time series across 40 weather years. The main points to emphasise in Fig.6 are the distinct nadir in cumulative renewable energy output in Australia's NEM during the late autumn and early winter months, and the inherent volatility in supply.

Fig.7, which focuses only on Victoria – perhaps the most important and sobering chart in this article – presents the opposing trends in electricity demand and renewables output in the NEM's Victorian region, particularly in the *Decarb.+Electrification Scenario*. The gap between Victorian demand and 'optimised Victorian renewable energy' is very significant and must be imported from adjacent regions, and supported by gas turbines and hydro power. As an aside, Fig.7 triggered this research.

40 years of optimised NEM wind and solar output (JSolve result)



40 years of electricity demand & renewable output in Victoria



One of our peers, when reviewing this article, queried whether Victorian renewable output might be uniformly increased through adding additional plant capacity. Our model has this as a potential option, but invariably prefers flows across interconnectors from adjacent regions, and local gas turbine production, as the least-cost option. Moreover, our model does not seek to connect any offshore wind due our assumptions of relative cost.

PF Model results

Generation costs have been derived by our PF Model. While 'PF' stands for Project Finance, the PF Model deals with an array of conventional and unconventional, on- and off-balance sheet financings and differing industrial organisation models. For our purposes, we simplify plant entry to the dominant format for each renewable and firming technology, as follows:

- Onshore Wind: Project Financed, on-market PPA, 75% contract coverage on a run-of-plant basis ('BBB' rated counterparty) with 25% merchant capacity;

- Offshore Wind: Project Financed, off-market CfD, 100% contract coverage on a run-of-plant basis (Government counterparty);
- Solar PV: Project Financed on-market PPA 75% cover;
- Open Cycle Gas Turbine or 'OCGT': Balance sheet financed (BBB metrics);
- Batteries: Balance sheet financed (BBB metrics);
- Pumped Hydro: Project Financed, 100% PPA or government financed on broadly equivalent terms.

We commence with 2024 equipment costs published by the Australian Energy Market Operator and then apply certain cost reductions, viz. -25% for solar PV and -50% for battery storage (i.e. assuming cheaper cells with balance of plant costs remaining static). Wind, gas turbine and pumped hydro costs are held constant. We then apply 2024 capital markets data – the details of which appear in Appendix V along with model logic. For clarity, we assume OCGTs are developed on-balance sheet (implying a higher cost of capital and commensurate merchant risk) and are capable of being retrofitted as fuels migrate to cleaner alternatives. We add $300/kW to OCGT capital costs for gas line-pack and dual-fuel firing.

Model results are presented in Fig.8. Energy producing plant – wind and solar PV – are presented according to their Average Total Cost including a normal return to equity. These represent equivalent PPA prices required under conditions of zero curtailment, of $78.7 and $59.5/MWh, respectively.

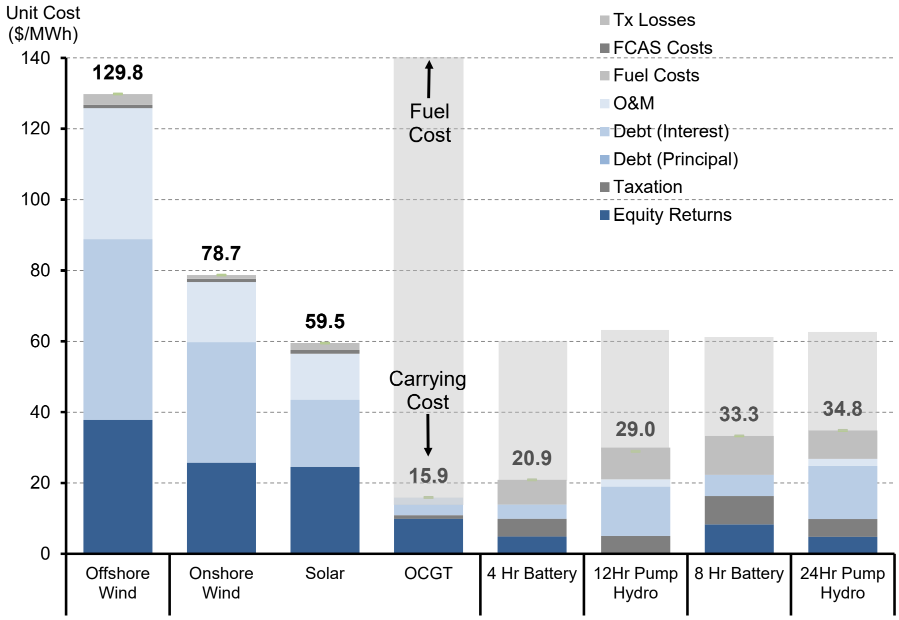
The dispatchable firming capacity options are represented by their capacity costs, with imputed fuel costs added separately. The reason for representing these technologies in this way is that it aligns with the NEM's forward markets for capacity (viz. $300 Caps). So, for example, the annual carrying cost of an OCGT is $15.9/MWh. To be clear, this is the annual fixed and sunk costs – the capacity cost of an idle GT - and excludes running costs. When a GT fires, it incurs unit fuel costs of $11-$18/GJ (at 10-12GJ/MWh) depending on the NEM region, time of year and GT technology, and additional variable Operations & Maintenance costs of ~$10/MWh. Thus at times GT marginal running costs (represented by the light grey bar) may exceed $200/MWh. Equivalent results can be seen for various batteries and pumped hydro plant. The costs of these storage assets are linearised into fixed (capacity) and storage (energy) costs, with both capacity and energy optimised within the JSolve model.

Within JSolve, each of the potential generation technologies is made available and optimised according to the primal objective function of minimising costs subject to reliability and CO_2 emission constraints. It is to be noted that our PF Model estimates of 8-hour batteries means they are not deployed within JSolve – the model prefers 12-hour pumped hydro plant. 12-hour pumped hydro has a lower carrying cost, although a marginally higher imputed fuel (i.e. pumping) cost but with considerably more storage, it has the beneficial effect of reducing GT operating duties.

Of course, should our assumptions around falling battery storage prices (of 50%) prove too conservative, or our pumped hydro costs prove too optimistic, then 8+ hour batteries would dominate the medium storage asset class. Indeed, the possible combinations of plant cost sensitivities are endless but to summarise, lower solar PV costs drive higher demand for short (battery) and medium duration (pumped hydro) storage. As medium and long duration storage costs rise, wind is prioritised. We do not consider 'seasonal storage' beyond the 2000MW, 350GWh Snowy 2.0 project.

From a firming perspective, lower battery costs increase their role in the dispatchable portfolio. Higher cost gas increases the role of pumped hydro. And, as storage costs (batteries and pumped hydro) reduce, the amount of 'spilled renewables' reduces – and vice versa. Similarly, higher GT marginal running costs due to higher fuel costs or future carbon values leads to higher uptake of both long-duration storage and renewable capacity.

PF Model Plant Entry Cost



JSolve: NEM Model Results

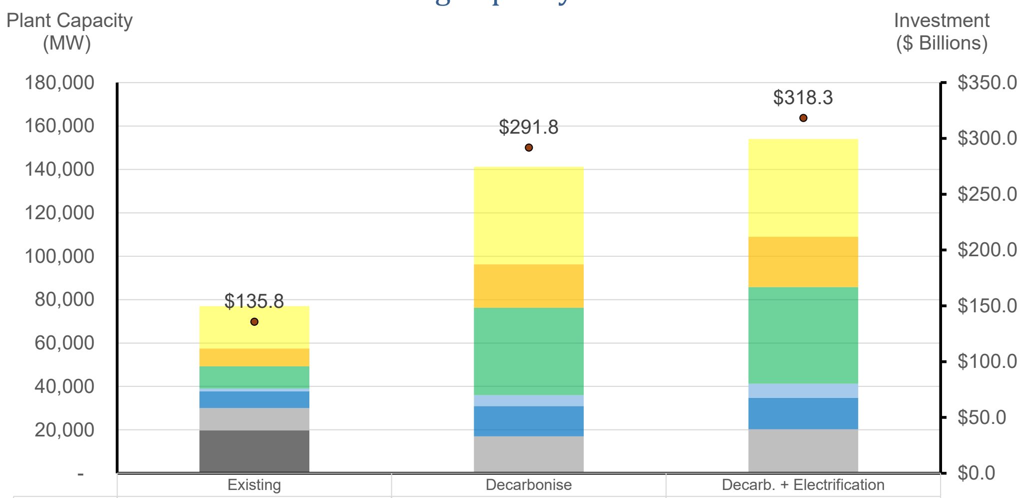
Given aggregate final electricity demand (Section 4.2) and renewable resources (Section 4.3), and plant costs (Section 4.4), what is the generation investment task facing Australia's NEM for the *Decarbonisation Scenario*, and how does it differ in the *Decarb.+Electrification Scenario*?

The results for our *Decarbonisation Scenario* and *Decarb.+Electrification Scenario* by comparison to the NEM's existing plant stock appear in the Fig.9 bar chart and accompanying table. The first bar depicts the NEM's incumbent 77GW plant stock (including rooftop solar PV), at a total capital value of ~$136 billion. The task facing the industry is to retire the 19.75GW coal fleet (see second last row of the inset table).

The second bar series presents the results of our *Decarbonisation Scenario*. Exit of the 19.75GW coal fleet requires the plant stock to expand to 140GW with a capital value of $292 billion. As the table highlights, this includes an additional 67GW of renewables, including wind (+30GW), solar (+12GW) and rooftop solar (+25GW) along with 17GW of dispatchable plant spread across batteries, pumped hydro and gas turbines.

The final bar series illustrates results for our *Decarb. + Electrification Scenario*, where plant must expand by a further +15GW or $26 billion. The main changes here are +7.5GW of utility-scale wind and solar PV, and +5.3GW of dispatchable plant.

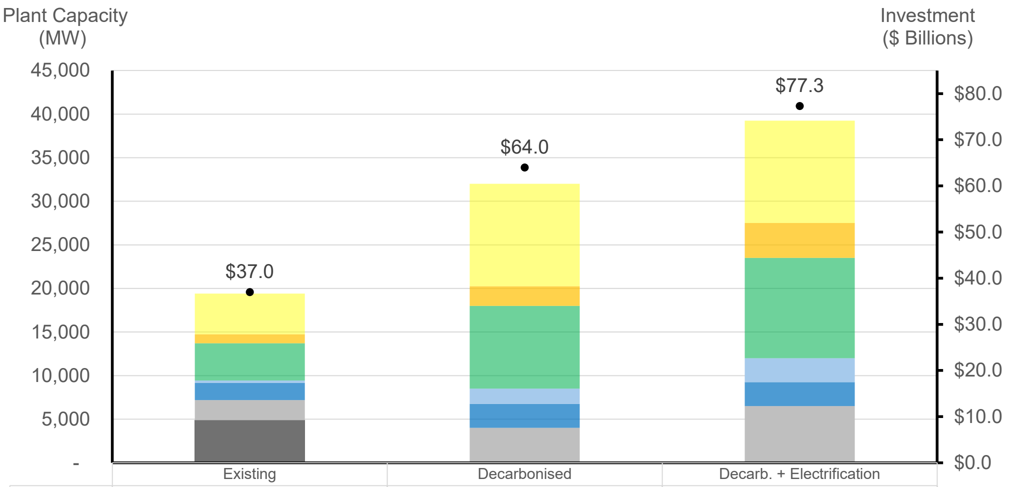
NEM Generation Investment vs Existing Capacity



	Existing	Decarbonise	Decarb. + Electrification
Rooftop	19,500	45,000	45,000
Solar PV	8,250	20,000	23,250
Wind	10,250	40,250	44,500
Battery	1,250	5,000	6,500
Hydro	7,750	14,000	14,500
Gas	10,250	17,000	20,250
Coal	19,750	-	-
Capital Cost	$135.8	$291.8	$318.3

The Victorian subset of this data illustrated in Fig.10. Why this subset is important at all is that half of the NEM's incremental plant associated with the *Decarb.+Electrification Scenario* is required in Victorian region. Compared to the existing plant stockin the region, wind capacity will need to more than double, and dispatchable plant capacity needs to triple.

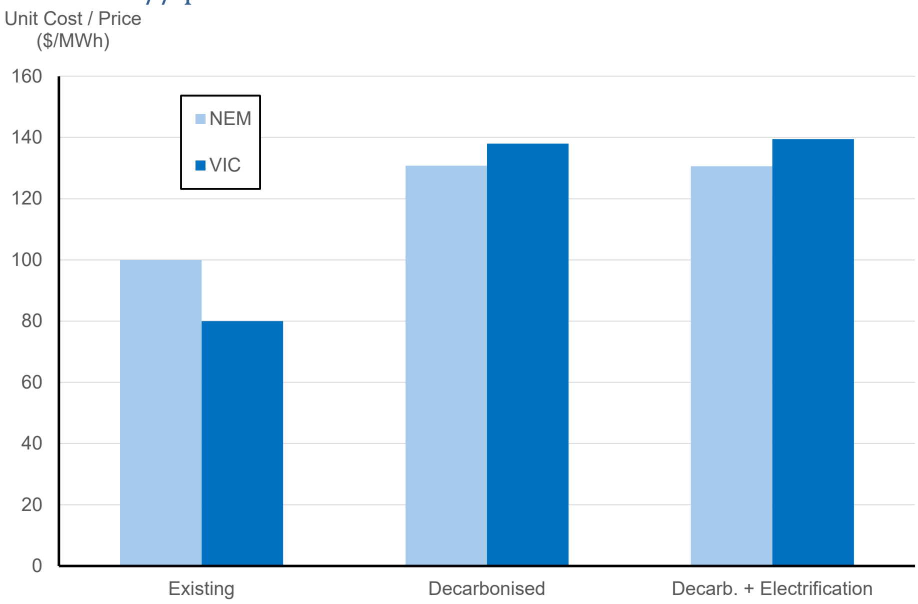
Victoria Generation Investment



	Existing	Decarbonised	Decarb. + Electrification
Rooftop	4,688	11,750	11,750
Solar PV	1,016	2,250	4,000
Wind	4,271	9,500	11,500
Battery	280	1,750	2,750
Hydro	1,962	2,750	2,750
Gas	2,318	4,000	6,500
Coal	4,883	-	-
Capital Cost	$37.0	$64.0	$77.3

Fig.11 illustrates our projections for the changes in unit prices in the NEM (weighted average of all regions) and in the Victorian region. Note Victoria's prices shift from below average to above average – a not unexpected result given the absence of a price on carbon and the dominance of Victoria's ~5GW brown coal fleet. As an aside, the counterfactual – replacing Victoria's aging brown coal fleet with new brown coal plant – produces a price forecast of ~$180/MWh. And even at this price level, it assumes bonds are able to be issued for such an investment at standard 'BBB' corporate rates, which we believe is not credible. But the result requires no further analysis.

Change in unit costs // prices: NEM vs. Victoria



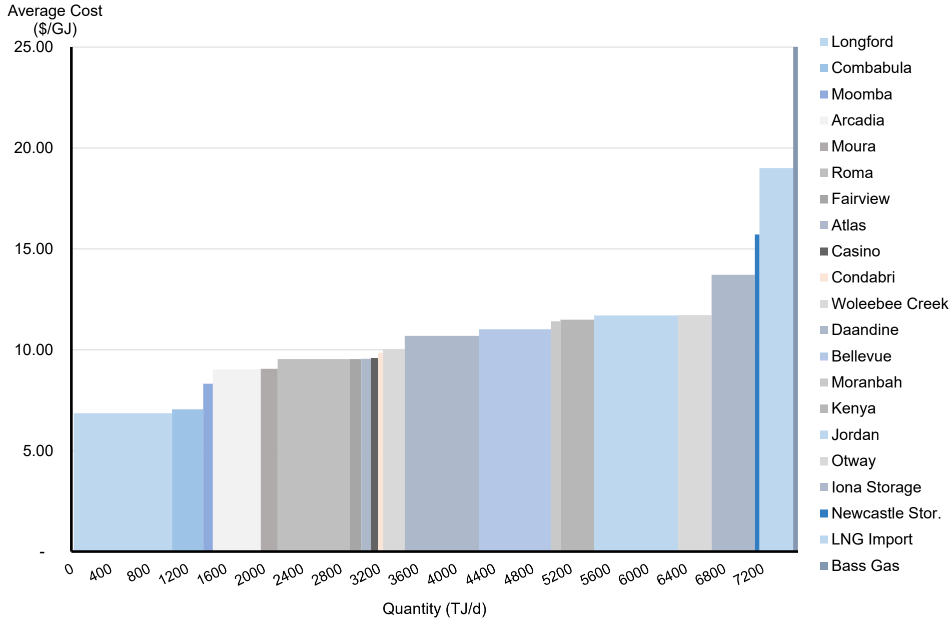
A feature of the model results in Figs.9-10 is the increase in GT capacity, driven by renewable resource intermittency, seasonality of those resources, and the absence of seasonal storage options at scale. In our power system model, GTs play a vitally important role in balancing supply and demand, being the *last line of defence*. The historic omission of the role of GTs in contemporary policy settings in Victoria and the Commonwealth is therefore somewhat curious – particularly given the widely accepted role such plant plays in the world's major electricity markets (especially in Europe and the US). Nonetheless, we assume policymaking will adjust to what is required. But in our JSolve model results thus far, we have not constrained GT operations vis-à-vis gas network limitations that may otherwise arise. And so our analysis must now turn to *how* the east Australian gas network may cope with transient demand shocks from the NEM's emergent GT fleet.

GPEM: Gas market model results

In our prior research (Simshauser & Gilmore, 2024), we found Australian electricity market modellers implicitly, and universally, assume the east Australian gas market is *endlessly flexible* and capable of meeting any level of demand from the GT fleet. We also found demand shocks from a larger GT fleet may routinely breach the outer operational boundaries of Australia's gas network as currently configured. Our *Decarb.+Electrification Scenario* reduces the demand for natural gas by 21%, so does this improve conditions?

To answer this query, we rely on our GPEM Model. We first examine the *Decarbonisation Scenario*, and then the *Decarb.+Electrification Scenario*. The GPEM Model was populated with the daily aggregate gas demand forecasts as summarised in Section 4.1. The aggregate gas supply function was drawn from data contained in Simshauser and Gilmore (2024) with one alteration – inclusion of an LNG Import Terminal in the NEM's Victorian region with an Average Total Cost of ~\$19/GJ[10]. The addition of LNG imports may be necessary to maintain the existing gas network in a secure state given declining production in the Bass Strait gas fields supplying Victoria's Longford gas facilities[11]. The aggregate gas supply function is presented in Fig.12. Details of the gas pipeline network appear at Appendix IV with the model logic.

East Australian aggregate supply function for natural gas



Source: Simshauser & Gilmore (2024).

The GPEM model was used twice to simulate years in the late-2030s, first to represent PoE50 weather, and then a PoE10 weather year, for both demand scenarios. Gas demand results are presented in Figs.13 and 16 with DomGas (residential, commercial and industrial gas consumption) appearing as the first demand segment, followed by LNG exports, then demand from the NEM's GT fleet, and finally, Unserved Demand which is represented by the black shaded areas.

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[10] See Victoria's gas crisis must be fixed now, but there are risks | Robert Gottliebsen | The Australian
[11] See AEMO at 2024-victorian-gas-planning-report-update.pdf (aemo.com.au)

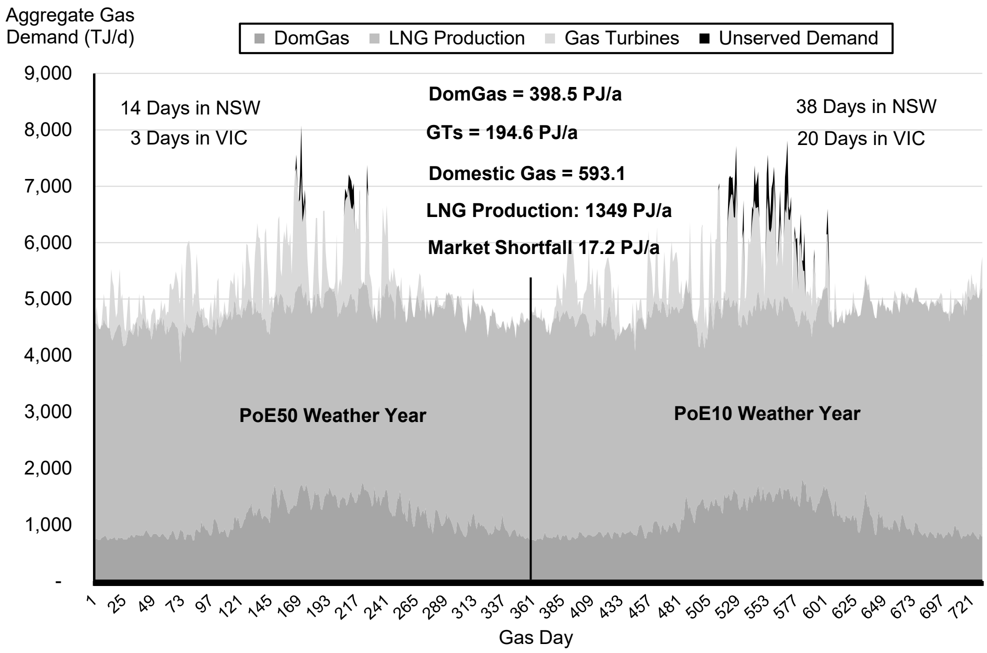
In the *Decarbonisation Scenario* (Fig.13), 593.1PJ/a is consumed by the domestic market which comprises 398.5PJ/a of DomGas and 194.6PJ/a from GTs. The market shortfall or 'unserved demand' (represented by the black shaded areas) is 17.2 PJ/a, across 38 days in NSW and 20 days in VIC during the PoE10 weather year. These shortfalls are significant and, to summarise, are caused by the conflation of three variables (all of which are unrelated to LNG production at Gladstone):

1. Maximum Demand (TJ/d) from the GT fleet. Recall from Tab.2 that gas turbine maximum demand surges to 2970TJ/d during critical event winter days, up from the historic maximum of 988TJ/d (see Tab.2 Line 18);

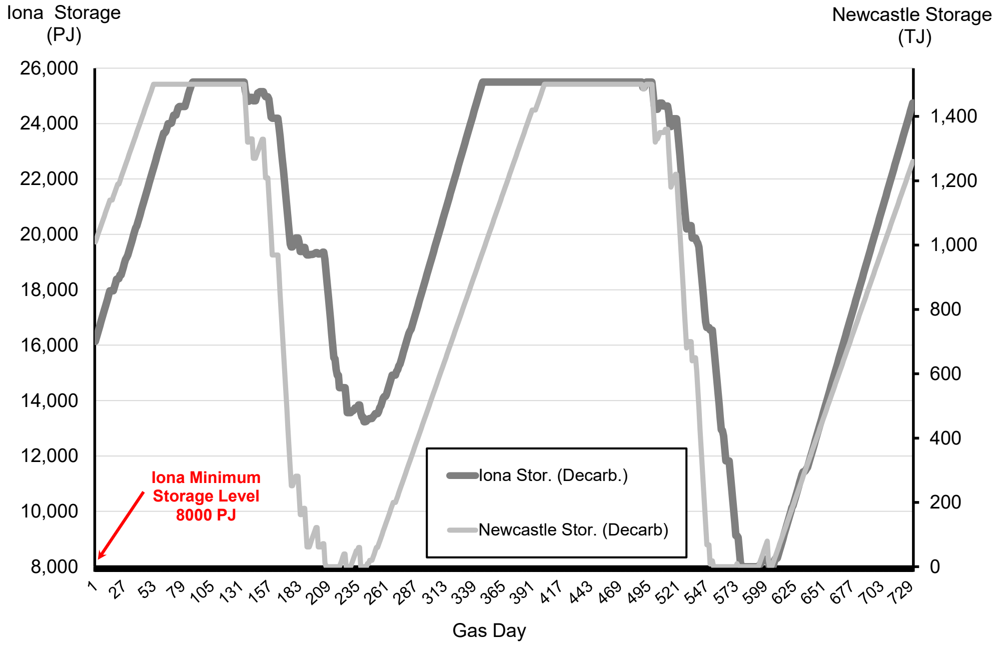
2. Location of marginal gas fields (in Queensland) and pipeline constraints south to NSW (and in turn, further south to Victoria) mean critical event peak loads cannot be satisfied through interstate transfers from Queensland given the existing network configuration; and

3. Existing gas storages in NSW and Victoria are exhausted due to the frequency, and intensity, of episodic demand shocks from the GT fleet, as Fig.14 illustrates.

Gas Demand in the Decarbonisation Scenario



Main storages: VIC (Iona, LHS) and NSW (Newcastle, RHS)



At one level, we should anticipate unserved demand events in our gas market model. After all, our JSolve Model has completely up-ended the NEM power system by turning over the entire coal-fired fleet (i.e. modelling a 'late-2030s market'). Yet our GPEM model has held the gas network constant or a '2024 market'. Given the difference in time-dynamics, gas network problems are entirely predictable. But how gas network problems are to be resolved is less predictable.

Recall that the NEM GT fleet is currently responsible for ~6% of gas market demand. Further, the Victorian government's policy to drive the electrification of the gas market does appear to send a signal vis-à-vis investment risk in new gas network assets. At least one gas (distribution) network utility in the NEM's Victorian region is seeking elevated fixed gas tariffs to charge consumers more now, given declining loads and a heightened risk of stranded network assets[12] in the future.

More importantly however, visual inspection of Fig.13 reveals an acute version of the peak load problem. Investing in gas pipeline assets for 3 days of use in a PoE50 weather year, and 20 days of use in a PoE10 weather year, presents complexities for investors (and consumer pricing) under ideal conditions, let alone in a structurally declining DomGas industry. Marginal sources of natural gas by way of pipeline route are up to 3000+ kms away. While additional compression will present low-cost options for increasing southerly flows (the potential for which is beyond the scope of our research), pipeline augmentations over the entire distance can hardly be economic for a peak load problem.

To summarise, this is not a Gladstone LNG export problem as is often assumed. To be clear on this, our model assumes DomGas loads are routinely prioritised over Queensland LNG Export loads during critical event days (noting production flexibility exists) – LNG terminals are therefore *not the cause* of unserved demand events. Fig.15 overlays the NSW and VIC outages against LNG production, and it can be seen LNG facilities are not operating at full capacity when the unserved load events arise. The black shaded areas highlight the *potential*

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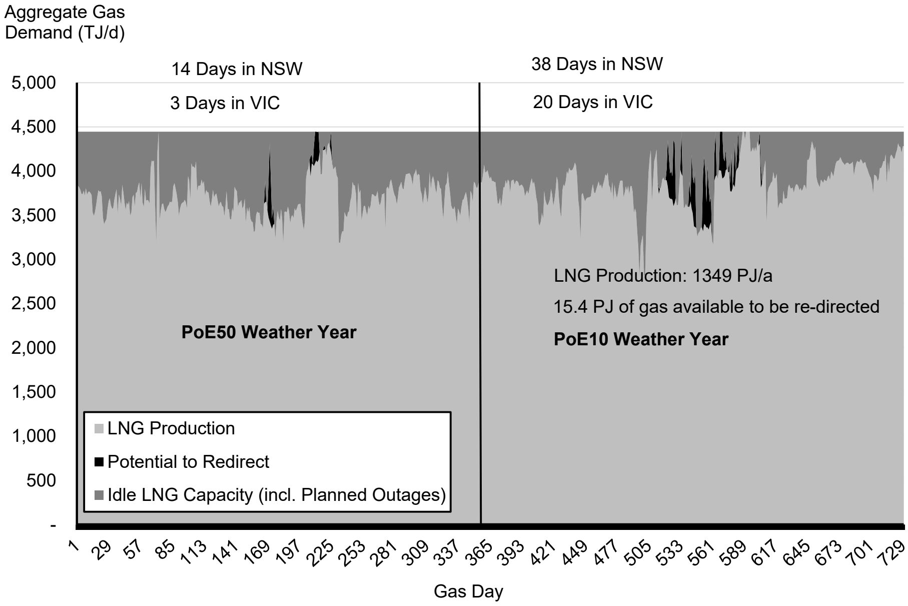
[12] Ausnet seeking faster recovery of its Regulatory Asset Base. See [Allan government electrification push blamed for gas bill hike | Gold Coast Bulletin]()

to redirect gas supply – the constraint beyond this is pipeline network congestion and inadequate storage.

LNG production vs Unserved Load in NSW and VIC



The state of the gas market under our *Decarbonisation Scenario* therefore presents as problematic for both the gas market and the power system. Unserved gas demand essentially translates to unserved electricity demand in the absence of some other storage (e.g. liquids for GTs).

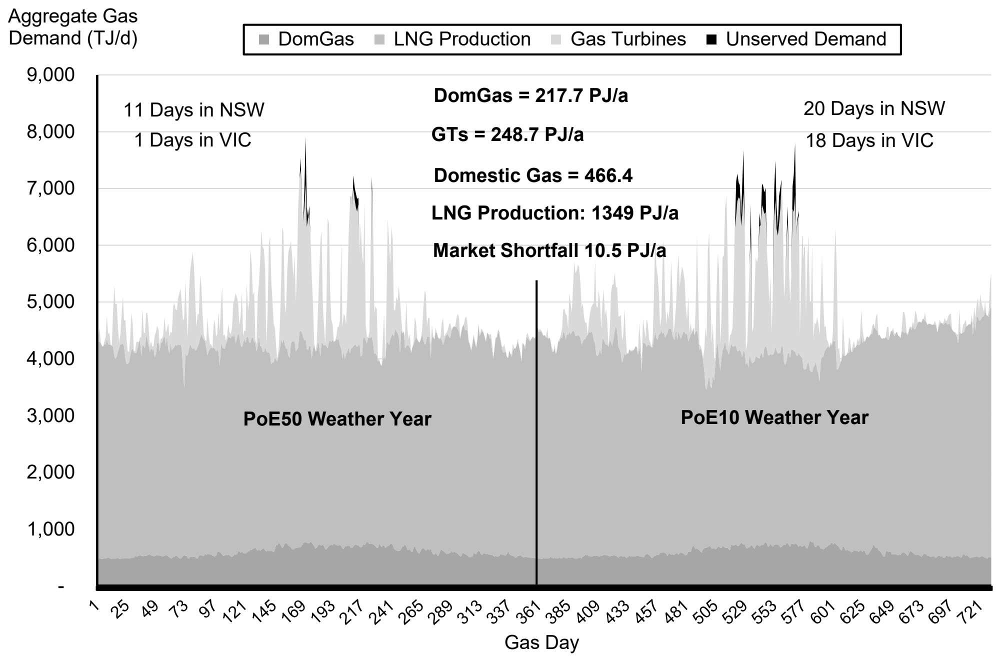
Does electrification mitigate the risks of natural gas shortfalls for the GT fleet? After all, recall from Tab.2 (Line 6) the *Decarb.+Electrification Scenario* led to a very sizable reduction in aggregate final gas demand, down -21% or 122.9PJ/a. Fig.16 reveals that the underlying problem persists with electrification. Specifically:

1. Our GPEM Model continues to find extensive unserved demand during critical event days in NSW and Victoria.

2. The severity has been substantially reduced in NSW because household gas demand is comparatively less material (aided by diversity of loads with the Queensland region).

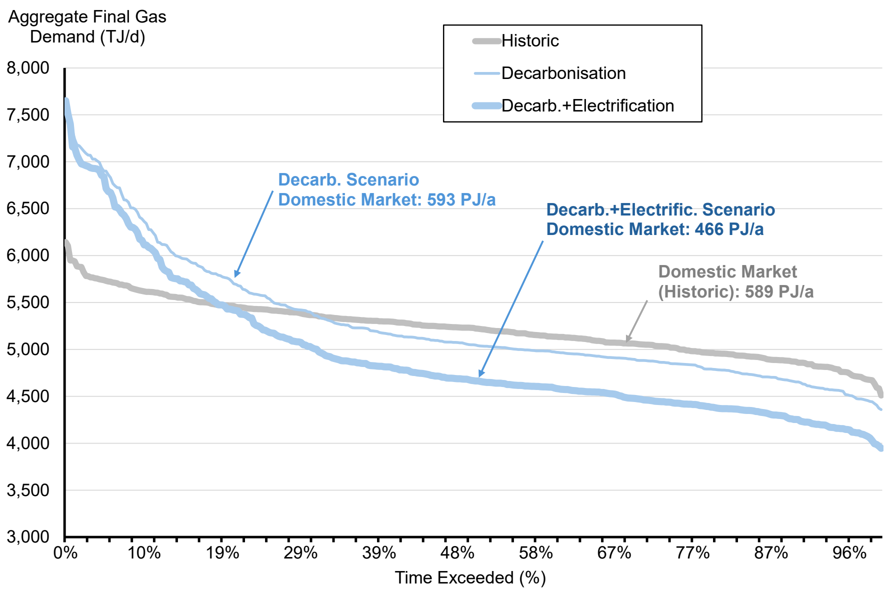
3. However, in Victoria the proportionally larger GT fleet required to manage *seasonal renewable output nadirs* – with GT operational duties amplified by electrification loads during critical event days – offsets reductions in DomGas demand.

Gas Demand in the Decarbonisation + Electrification Scenario



To explain the situation in Victoria, Fig.17 contrasts the annual (PoE10) gas load duration curves from the historic dataset with the *Decarbonisation Scenario* and the *Decarb.+Electrification Scenario*. What is apparent from these load duration curves is the extent of the peak load problem caused by the required GT fleet during Victorian winters.

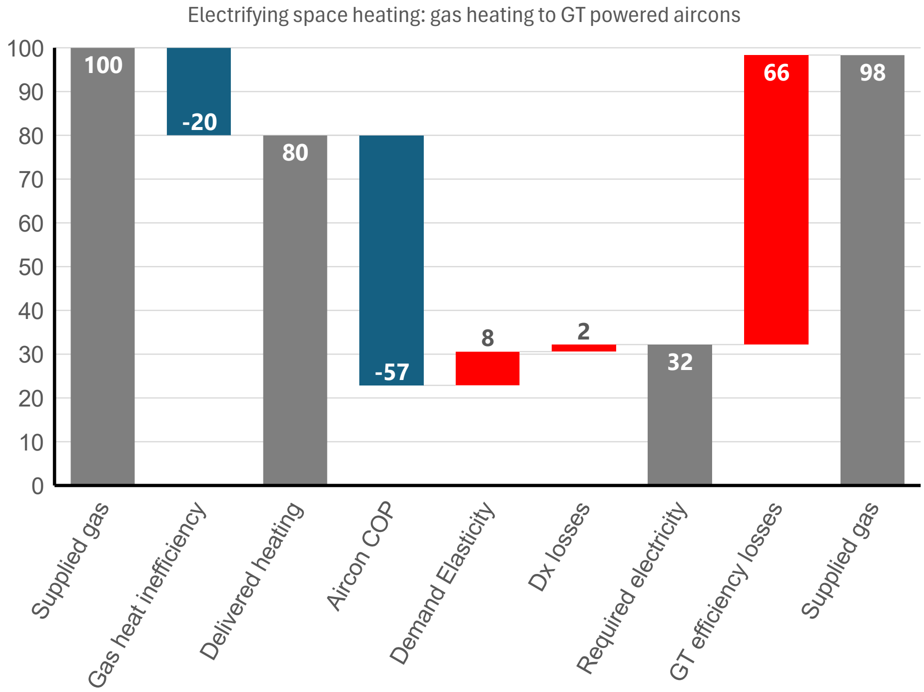
Gas Load duration curves – Historic vs Scenarios



From Fig.17 it can be seen that NEM-wide, electrification reduces annual gas demand quite significantly – from 593PJ/a to 466PJ/a (c.20%). However, maximum demand has no visible change at all – peaking at 7800TJ/d. Similar results are shown for Victoria, with annual consumption falling from 257.0PJ/a to 196.2PJ/a, but maximum demand rising from 1,785TJ/d to 1,823TJ/d.

Fig.18 illustrates the nature of the problem we identify by tracking energy consumption at the Victorian household level.

Household critical event winter day - gas use waterfall



In this example, an existing household gas heating system is assumed to have a heating efficiency of 80% and require 100 units of gas energy. A reverse-cycle air conditioning system with a Coefficient of Performance[13] of 3.5 could deliver the 80 units of heat energy with an electrical input of only 23 units of delivered energy. Allowing for a potential increase due to the consumer' response to price differences and for transmission and distribution losses, the as-generated electricity requirement might be 33 units of energy. Provided policy sequencing occurs such that the system is dominated by VRE, On most days this energy is delivered through wind and solar generation and firmed by energy storage. However, on critical event days GTs are the marginal generation technology. GTs have a sent-out efficiency of 33%, meaning 99 units of input gas is required to provide the service previously supplied by 100 units.

Policy implications and concluding remarks

At the outset, we noted more than $83 billion has been invested in 35GW of wind, solar PV and dispatchable firming capacity (batteries, pumped hydro and GT plant) in the NEM over the past 7-8 years. Additionally, the NEM has the world's highest take-up rates of rooftop solar, which now exceeds 20GW of capacity behind the meter. Australia's energy transition is thus well underway. More than 29GW of renewable energy projects have reached financial close since Australia's Renewable Energy Target or RET was first introduced in 2000. The RET has been responsible for ~11.2GW of renewable investment commitments (2000-2018), on-market transactions have delivered 16.6GW (2018-2024) and government CfDs have accounted for the balance (2.1GW) of projects that have reached financial close.

Yet Fig.1 illustrated the run of investment, and new renewable commitments in particular, appeared to visibly slow during the 2024 financial year. This may be cyclical and therefore a transient matter reflecting a market adjusting to new information (i.e. price inflation), in which case there is no need for policymaker intervention. If structural, with projects becoming progressively harder to develop (due to e.g. changes in environmental laws, or because at 40% market share, the easy projects have been done and from here on the hard work begins), then policy adjustment may be required.

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[13] Coefficient of Performance is essentially heating energy out divided by electrical energy in, and in this instance is 3.5:1.

One issue which presents as problematic is flexible firming capacity. The limits of the transmission network, its (costly) augmentation and the seasonal pattern of renewable output means a large fleet of storage and firming capacity is required. Batteries will unquestionably be the power system's intra-day workhorse, helping move wind and solar through space (via existing transmission networks) and through time. But our simulations based on 40 years of coincident wind, solar and electricity demand data reveal the NEM cannot rely on short duration batteries alone. Our central electrification scenario required almost 35GW of GTs and hydroelectric (much of this pumped hydro) plant capacity. The NEM currently has ~20GW.

NEM policymakers at both State and Commonwealth levels will need to monitor both renewable investment commitments and firming and storage plant commitments against the expected trajectory and optimal portfolio to ensure policy settings, and policy sequencing of decarbonization and electrification, remains tractable. Being transparent on these assessments will be important to investors.

Ultimately, all policy reforms face *'speed limits'*. As a simple analogy, when government finances enter an unstable zone and fiscal policy needs to be restrained, spending cuts of more than 1% of Gross Domestic Product are thought to do more economic harm than good. This doesn't mean the task of fiscal repair loses importance – but timeframes dictate how to maximise the probability of success.

So it is with power system reform. Speed limits to reforms exist, and they exist across many dimensions – from customer tariffs to wholesale market reforms. In the present case, transitioning from coal to renewables, and electrifying gas loads, are both essential elements of a net zero policy framework. But jointly, they may face *speed limits*. A necessary pre-condition for electrification is that renewables and an associated (and diversified) fleet of firming capacity enters *at pace*. This then provides the very foundations for the decarbonisation objective to be met, with prices and reliability of supply being maintained within the expected envelope (noting the political economy of electricity prices, and supply-side induced unserved load events).

Conversely, if renewables and firming project entry rates experience a structural slowing (which appears to be the case), it is at least possible that electrification of gas loads may work against the decarbonisation objective in the short- to medium-run. The reason for this is axiomatic, and forms the key policy implication arising from this research:

1. If renewable development slows, and electrification of gas loads accelerates (and leads to sharply rising electricity loads), extending the service life of coal plant to maintain a secure power system is a predictable outcome given the political economy of electricity supply.
2. Unfortunately, extending coal plant lives then has the potential to create a vicious cycle of slower renewable entry rates. Quasi-coal exit announcements, followed by policy-driven coal plant life extensions facilitated by government, visibly detract renewable investor confidence and their PPA counterparties in terms of forward commitments.
3. Policymakers should therefore be seeking to alleviate 'speed limits' where possible, and accelerate the pace of decarbonisation to ensure Australia's carbon budget can be met.
4. However, this needs to be done with full knowledge of where we are today. And this means policy sequencing is important, viz. ensure decarbonization is well advanced before tackling electrification due to (2) above.

In Section 4, we noted the NEM's existing plant stock has a capital value of ~$136 billion. Our decarbonization scenario suggests a future plant stock of ~$291 billion. The multiple required provides some insight as to the task under ideal (i.e. modelled) conditions. Our electrification scenario suggested relatively modest increases in new generation plant (~$26 billion) – however half of this additional plant was required in Victoria where gas demand is prominent. Monitoring entry rates for renewables, flexible firming capacity and interconnections into the Victorian region of the NEM will therefore be important – as will amending policy as required.

Finally from a policy perspective, we found the shape of the gas load duration curve in our future scenarios to demonstrate sharply deteriorating load factors – the very definition of the peak load problem identified in energy systems dating back to Hopkinson (1892). Unfortunately, Boiteux's (1949) elegant mathematical solution was not designed for an industry that is at risk of structural decline. Practical policy solutions will require larger gas storages to deal with sporadic PoE10+ weather events. And realistically, while rarely utilised, such storage is likely to be essential and unlikely to be commercial – suggesting further government investigation (and likely intervention) may be required. Planning around alternate fuels including liquids, biodiesel and hydrogen derivatives for critical event days presents as the other logical policy pursuits.

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APPENDIX

Appendix I to III are available at [NEM Elec Appendix]