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Rooftop solar PV, coal plant inflexibility and the minimum load problem

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Abstract

Australia's National Electricity Market (NEM) has amongst the highest take-up rates of rooftop solar PV in the world. In the NEM regions of Queensland and South Australia, ~44% of detached houses have installed a solar system. As with California, this has produced a distinctive load shape commonly referred to as the 'duck curve' – but unlike California, the Queensland version is being driven by non-scheduled (i.e. largely uncontrolled) distributed energy resources. The proliferation of rooftop solar PV reduced the rate of growth of power system peak demand but is now driving a rapid deterioration in power system minimum demand. When combined with inflexible legacy coal plant, it leads to the 'minimum load problem'. This new frontier appears to be emerging at a rate faster than the system may be able to cope with absent very careful planning. In this article, we examine the feasibility of dispatch with ever-expanding rooftop solar PV resources in the NEM's Queensland region and minimal demand elasticity. We find episodes of intractable dispatch throughout the year with rising intensity in the winter and spring months. Furthermore, we find no ability to 'export your way out of the problem' via larger interconnectors because the same problem is emerging in adjacent regions at the same time. Resolution requires inflexible coal plant exit, and flexible battery and gas turbine plant entry – a set of parameters that Australia's energy-only market has thus far navigated imperfectly.

Key words: rooftop solar PV, minimum load problem, electricity markets.

JEL Classification: D25, D80, G32, L51, Q41.

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1. Introduction

As thermal power systems transition from low- to high-levels of intermittent renewable energy market shares, various economic and technical issues emerge. Economic issues usually commence with transient merit order effects, an increasing prevalence of generation plant curtailment and rising frequency and intensity of negative price events during periods of high renewable output (see for example Newbery, 2017, 2021, 2023; Newbery and Cambridge, 2023). Emerging technical issues include faltering system strength, deteriorating inertia and rising ramp rate requirements (Badrzadeh *et al.*, 2020; Hardt *et al.*, 2021; Simshauser and Gilmore, 2022).

In the initial stages of variable renewable energy (VRE) entry with market shares of up to ~20%, few problems typically occur from a technical perspective. More likely are economic issues such as merit order effects and the rising incidence of negative spot prices (see for example Forrest and MacGill, 2013; Cludius et al., 2014; Bunn and Yusupov, 2015). Once renewable market shares rise above 20% and merit order effects intensify, the exit of the marginal coal plant becomes predictable through the combined forces of falling prices or 'price impression effects' (Edenhofer et al., 2013; Hirth et al., 2016) and falling production or 'utilisation effects' (Hirth, 2013; Höschle et al., 2017; see also Nelson, 2018; Simshauser, 2018, 2020; Rai and Nelson, 2020).

Exit of marginal coal plant can be expected to produce a rebound effect vis-à-vis wholesale market prices (Felder, 2011). All things equal, sharply rising wholesale prices which follow exit serve to 'prime' VRE entry (Simshauser and Gilmore, 2022). Continual VRE entry over time means the remaining inflexible plant will, once again, experience adverse price impression effects and utilisation effects, ultimately forcing the next marginal coal plant into financial distress and exit (Simshauser, 2020).

This economic cycle of VRE entry, price impression effects, utilisation effects, coal plant exit and re-bounding prices will be accompanied by a slowly rising series of technical problems due to the cumulative loss of synchronous plant, viz. system strength shortfalls and falling inertia (Simshauser and Gilmore, 2022). The short-term solution is to constrain-off inverter-based resources in the affected node(s) and to constrain-on synchronous plant (Hardt et al. 2021). In economic terms, this means the potential output of zero marginal cost VRE plant is curtailed, and higher cost coal and gas plant is dispatched in its place with the mass of spinning coal and gas turbines remediating the system strength shortfall.

Long term, system strength shortfalls ultimately require the tuning of inverter-based resources and the installation of synchronous condensers (Badrzadeh et al., 2020; Hardt et al., 2021). This entry-exit cycle with the accompanying technical challenges has occurred in Australia's NEM and consequently is at the forefront of developments on system strength modelling and remediation (see Hardt et a., 2021).

However in the NEM's Queensland region, a new frontier is emerging – *the minimum load problem*. Prima facie, the origins of the minimum load problem can be colloquially described as a combination of the 'duck curve' (CAISO, 2013; Denholm *et al.*, 2015), viz. the hollowing out of daytime load via solar PV output, and an oversupply of thermal plant with 'must run' minimum stable loads. But unlike other solar-rich regions such as California which have very high levels of utility-scale solar PV (Sioshansi, 2016; Ahmad *et al.*, 2020), the source of the problem in Queensland is mass take-up rates of distributed rooftop solar PV across ~44% of detached households (Simshauser, 2022).

The distinction here between Californian utility-scale output and Queensland rooftop PV output may appear subtle, but it is crucial. The Californian duck curve is a net-load concept and arises through high market shares of utility-scale solar, which are scheduled, dispatchable plant. Because they are scheduled plant, they can also be curtailed when required to maintain system security (Denholm *et al.*, 2013; Ahmad *et al.*, 2020). The source of Queensland's problem comes from non-scheduled (small-scale) rooftop solar PV which is non-scheduled, largely uncontrolled for plant under 5kW and therefore non-curtailable – absent deliberately spiking voltage levels above inverter set-points on specific distribution feeders. The minimum load problem in Queensland is intensifying and is consuming more focus than the peak load problem.

From a system operations perspective, issues principally arise when the set of inequality constraints employed within wholesale market algorithms vis-à-vis minimum and maximum generation capacity limits and limits on power transfer of transmission branches are no longer capable of providing technically feasible solutions to clear aggregate final demand. Since rooftop solar PV cannot be constrained off, coal unit de-commitment may be required. But this may introduce issues with respect to system strength, or inadequate generation plant for evening peak demand. Longer run remediation by way of synchronous condensers and flexible batteries and gas turbine plant may suffer from imperfect entry (viz. investor hesitation vis-à-vis risks of missing money, construction time lags etc) unless very carefully planned in response to this emerging problem.

In this article, we examine the evolution of *the minimum load problem* in Queensland and analyse the power system in granular detail for the future year 2030 in order to investigate the likely prevalence of infeasible dispatch periods. Our agent-based model replicates the National Electricity Market but radically increases the resolution via incorporating 59 nodes (cf. five regions). The model contains both a mathematical and network structure sufficiently detailed to identify constraint relaxations necessary across generation and transmission transfers in attempts to secure technical feasibility.

Our model results are as follows. We find ~700 half-hour intervals per annum in which *the minimum load problem* becomes binding – driven by duck curve effects and an oversupply of inflexible thermal plant in the NEM's Queensland region. This occurs primarily in the winter and spring months, with model results suggesting this is a largely coincident problem across regions. Consequently, 'exporting your way out of the problem' thought augmenting interconnectors to adjacent regions is non-viable. Ultimately coal plant exit with flexible plant entry is required given limited demand elasticity.

This article is structured as follows. Section 2 surveys the relevant literature. Section 3 outlines our ANEM model. Section 4 presents evidence linking emergence of feasibility issues with the complexities of minimum demand and inflexible production characteristics. Section 5 investigates the nature of constraint relaxations needed to secure feasible and optimal market solutions. Policy implications and concluding remarks follow.

2. Review of literature and context

Throughout the 20th century, there were two primary problems facing power system planners, i). defining the optimal plant mix given periodic and uncertain demand, and ii). defining efficient prices capable of supporting the overwhelming fixed and sunk costs associated with the optimal plant mix. We examine how such problems were resolved and explain the limits of these theoretical constructs in the presence of the minimum load problem.

2.1 Optimal plant mix and the peak load problem

The classic static partial equilibrium framework which defined the optimal plant mix for a thermal power system emerged through the works of Calabrese (1947), Boiteux (1949), Turvey (1964, 1968) and Berrie (1967). Calabrese (1947) first set out the method for simulating uncertainty of plant availability. Boiteux's set out the critical features of generation plant which were further refined in Turvey (1964, 1968). Berrie (1967) would develop what would become the benchmark static partial equilibrium model for power system planning, comprising a load duration curve and marginal running cost curves for perfectly divisible mixed technologies, with the intercept representing annualised fixed and sunk costs, and the slope representing the marginal cost of production.

US economists extended the analysis with Steiner (1957) incorporating uncertain demand and Williamson (1966) accounting for plant indivisibility. An Australian/French duo comprising Booth (1972) and EdF Chief Economist Boiteux (cited above) set out the quantitative methods and processes that would underpin the core of all structural power system partial equilibrium models reliant on thermal plant. Crew and Kleindorfer (1976) and Wenders (1976) formalised mixed technologies.

The basic premise of this line of research was that for a given load curve, there was an optimal mix of base, intermediate and peak plant that would minimise costs whilst satisfying periodic demand within a given reliability criteria and Loss of Load Probability. For a thermal system, this would typically collapse down to coal (or nuclear) undertaking base duties, combined cycle gas turbines for intermediate duties, and natural gas (or oil-fired) open cycle turbines undertaking peaking duties and providing a suitable reserve plant margin. Appendix I sets out a relevant example. What such planning led to was a prevalence of large (and inflexible) base load generating fleets in order to minimise system cost in a world in which intermittent and asynchronous VRE was not envisaged.

2.2 Efficient prices and the peak load problem

Electricity utilities first emerged in the late-1800s and to the best of our knowledge was the first industry to reveal *the peak load problem*. The proliferation of residential customers ('or short hour customers using electricity for 'evening illumination') was driving capital-intensive capacity additions to meet peak demand (Greene, 1896). As a result, power system capacity factors were plunging, and uniform prices were failing to recover the spiralling fixed and sunk costs of the ever-expanding footprint of the emerging electricity utilities. It was at this point that otherwise solid utility businesses were headed towards financial distress (Wright, 1896).

The two-part tariff comprising a maximum demand charge ($/kW) and a variable energy rate (¢/kWh) emerged in response (Hopkinson, 1892; Greene, 1896; Wright, 1896). The demand charge was intended to form the dominant component to match the industry's onerous fixed and sunk costs. Doherty (1900) would later extend this to the three-part tariff by including a fixed charge.[1]

Bye (1929) would develop the first variant of peak-load pricing for public utilities by combining the principles of off-peak pricing at marginal cost with peak period prices bearing some resemblance to the classic works of Dupuit (1844) and Ramsey (1927). From here, Hotelling (1938) established that tariffs should be set at marginal cost with capacity charges as demand approached the limits of installed capacity, and to deal with any shortfall through general taxation. Lewis (1941) emphasized the importance of system peak (*cf.* the engineering approach, which had focused on non-coincident individual customer peak loads).

But the breakthrough would once again involve *Electricité de France* Chief Economist, Marcel Boiteux, and almost simultaneously Houthakker in 1951 (Nelson, 1964; Williamson, 1966; Turvey, 1968; Joskow, 1976; Bonbright et al., 1988). Boiteux (1949) reconciled system marginal cost and the long run marginal cost of plant – and substantially reconciled system marginal cost with average total cost – courtesy of a fundamental proposition. With an optimal investment policy, price set at marginal cost exactly equals the marginal cost of the marginal plant, which in turn is equal to the average cost of the marginal plant.[2]

[1] The three-part tariff added a fixed customer charge to the bill reflecting operating costs (i.e. local connection, meters, meter reading costs, and customer billing) and with the cost allocation method of determination driven by the number of utility customers. See Doherty (1900).

[2] To see how optimal investment policy, short-term and long-term pricing is reconciled for a fleet of power stations under the conditions envisaged by Boiteux (1949), let ξ_i^1 and ξ_i^2 be gross margin in period i before and after plant expansion, where price p_i^k applies to each period i and let smc_i^k be system marginal running cost. Let β_e be the capacity cost of the new plant, and mc_e be the marginal running cost of the new plant, with smc_i^1 and smc_i^2 being system marginal running costs before and after the addition of new plant. Let q_i equal demand growth to be serviced in each hour and θ_e be output to be produced by the new plant each hour. Optimal investment will proceed at the margin when the following condition becomes binding:

Translating Boiteux's (1949) principles into a schedule of optimal prices thus became relatively straightforward – viz. when there is idle capacity (i.e. off-peak), tariffs should be set to system marginal running cost. In peak periods, set tariffs to long run marginal cost (i.e. system marginal running costs plus the carrying capacity of a gas turbine).

2.3 The minimum load problem – base plant non-convexities

The power system principles set out in Sections 2.1-2.2 adapt readily when renewables are initially introduced (e.g. less than ~20% VRE market share). Indeed, the classic static partial equilibrium framework set out in Berrie (1967) was modified by Martin and Diesendorf (1983) to accommodate intermittent wind resources (see Appendix I, net load duration curve). The basic concept involves deducting the forecast output of intermittent renewable resources from the (gross system) load duration curve, thus producing a 'net' load duration curve to be met by dispatchable (thermal) resources.

In more advanced stages of decarbonising a thermal power system, intermittency becomes highly problematic (Newbery, 2023). Static modelling begins to unravel as renewable market share reaches non-trivial levels. The reason for this is, as our Section 5 modelling results subsequently illustrate, baseload plant inflexibility. Under the classic static partial equilibrium model, the non-convexities of base plant operations and associated inflexibility is of little consequence. This changes as VRE is introduced.

Operational plant flexibility has two important facets that conveys considerable economic value in an operating environment where intermittent renewables and, and solar in particular, dominate the aggregate supply function:

1. plant which can start-up and shutdown quickly; and

2. plant with fast ramping capability and low 'minimum load' capability.

Baseload coal fired generation have non-zero minimum stable operating loads (ca. 40-50% of nameplate capacity) at which the plant cannot operate below on a sustained basis without damaging the plant itself. Furthermore, they have an inability to shut down and start-up quickly. Depending upon whether a coal plant is in a hot or cold mode of operation prior to re-starting, it can take 6-24 hours to start-up and synchronise to the grid. In short, such plant struggle to manage production non-convexities in markets increasingly dominated by VRE.

An additional consideration is the requirement for more aggressive ramping of plant (as Fig.3 and Fig.5 subsequently reveal). While coal generators can and do undertake load following duties, extensive ramping throughout the technical operating envelope can be expected to place considerable strain upon aging legacy plant (especially mills) and produce rising forced outage rates and maintenance expenditures.

To summarise, critical non-convexities assumed away in both static and computable general equilibrium models become highly problematic once the VRE fleet market share begins to exceed ~25% (Simshauser and Gilmore, 2022), and the subset of solar exceeds ~12%, holding the thermal fleet constant (Nicolosi, 2012; Hirth, 2013; Simshauser, 2018).

2.4 The minimum load problem – solar PV and 'the duck curve'

The 'duck curve' can be first traced back to analysis undertaken by California's ISO following a wave of utility-scale solar PV investments which over time *cannibalised* the load available for inflexible generation plant (CAISO, 2013; Denholm *et al.*, 2015). In the NEM's Queensland region,

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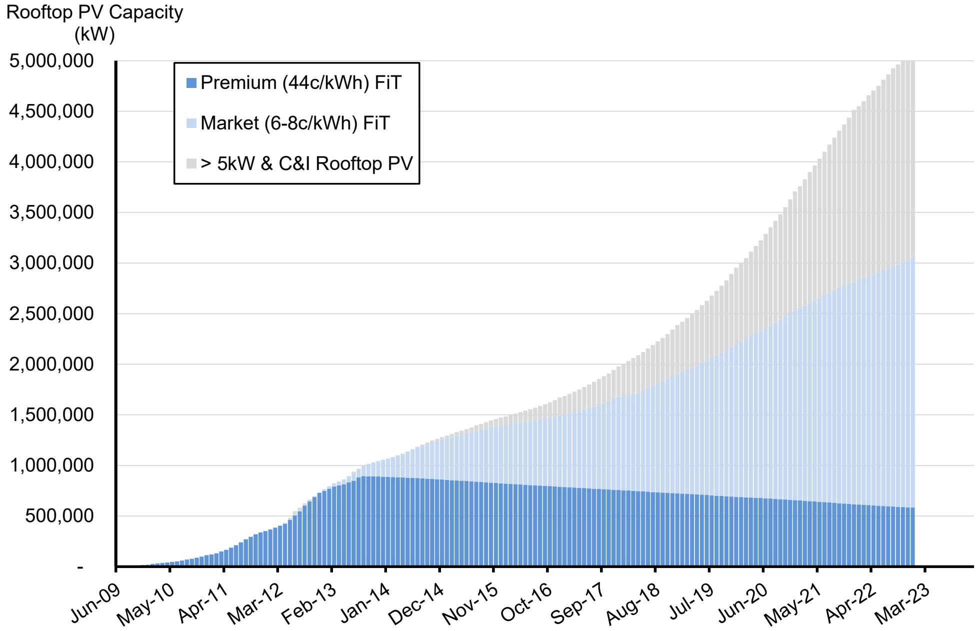
$$PV\left(\sum_{i=0}^{n}\left(\frac{\xi_i^1+\xi_i^2}{2}\right).q_i+\left(\frac{smc_i^1+smc_i^2}{2}-mc_e\right).\theta_i\right)-\beta_e\geq 0 \ \mid \ \xi_k=\left(p_i^k-smc_i^k\right)$$

the 'duck curve' has taken on a new level of complexity. It has arisen through *non-scheduled* rooftop solar PV – large numbers of which presently cannot be controlled or curtailed.

Figure 1 illustrates the take-up rate of rooftop solar PV in Queensland over the period 2009-2022 – rising to 5,000 MW of capacity in a system with a peak demand of ~10,000 MW (i.e. 44% of Queensland's detached households have installed a rooftop solar PV unit). In Fig.1, the run-up in rooftop solar PV is presented with three market segments, i). early household adopters who qualified for a generous subsidised feed-in tariff of 44c/kWh for net exports (cf. residential tariff of ~24c/kWh), ii). households paid a wholesale market rate of 6-8c/kWh for net exports, and iii). small businesses that have installed rooftop solar PV capacity.

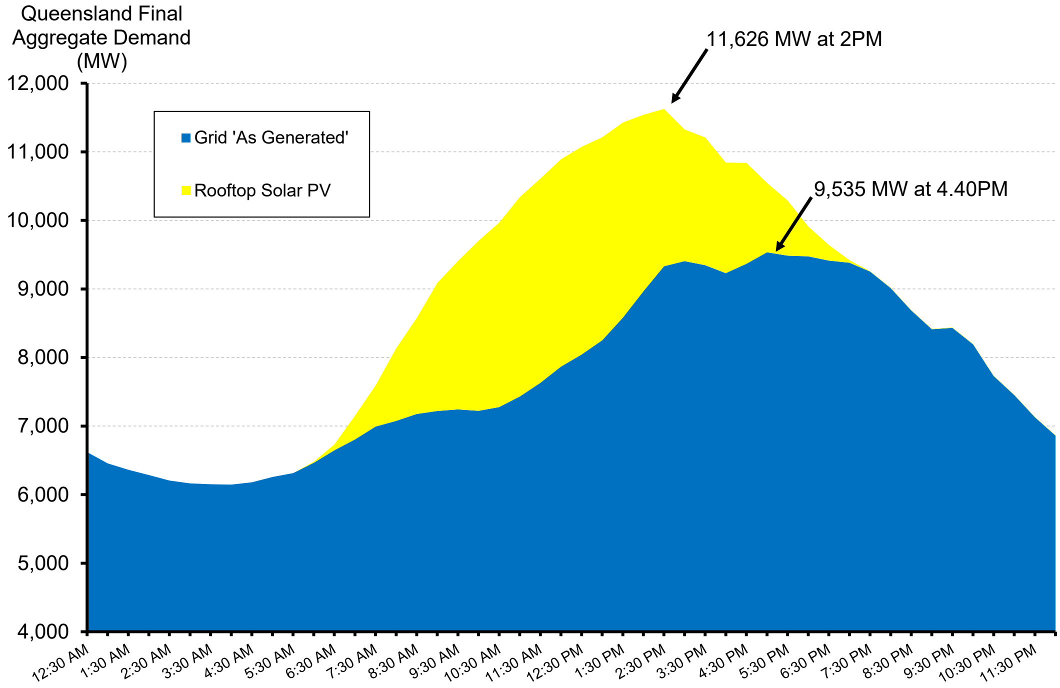
Figure 1: Rooftop solar PV capacity in Queensland (2009-2022)



Source: Simshauser (2022)

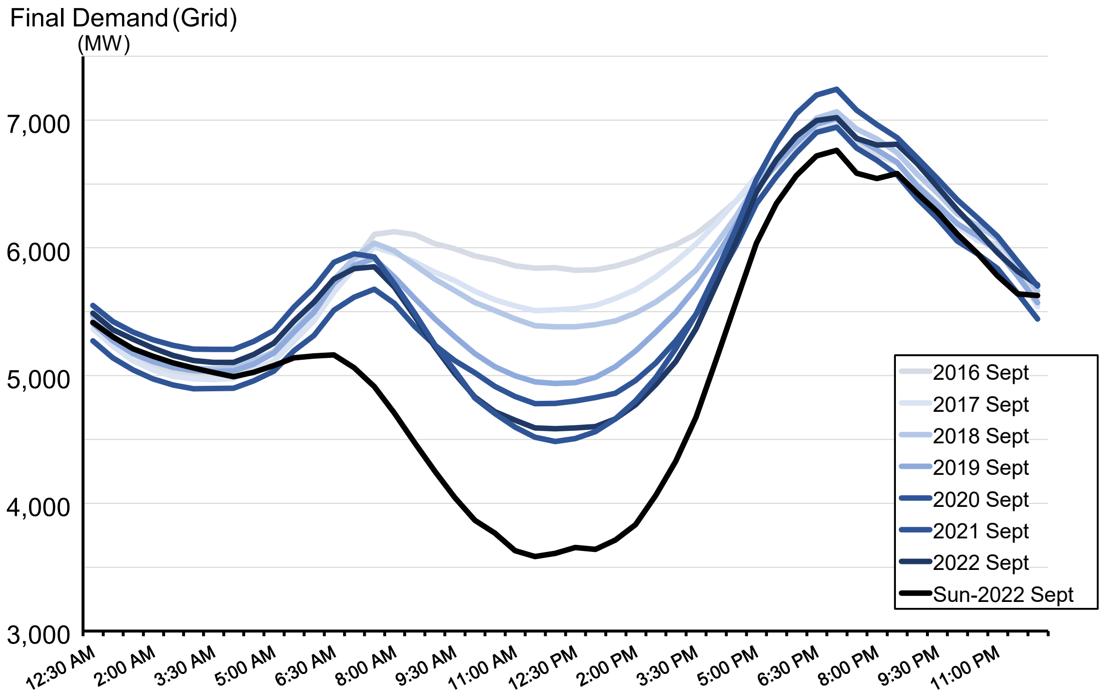
During summer months, household air-conditioning loads are high and absorb distributed solar resource output, as highlighted in Fig.2. The blue-shaded area depicts grid-supplied electricity, which exhibits a peak of 9,535 MW at 4:40pm. Note that maximum 'final' demand of 11,626 MW occurs earlier in the day, at 2pm with rooftop solar contributing ~2800 MW.

Figure 2: Aggregate final summer demand (grid-supplied & rooftop solar PV)



During the spring months, and September in particular, ambient temperatures are mild with good solar irradiation, meaning household loads are moderate and rooftop solar output is strong. These conditions combine to produce a pronounced residual demand curve, *excluding utility-scale solar PV*, consistent with the duck curve (Fig.3).

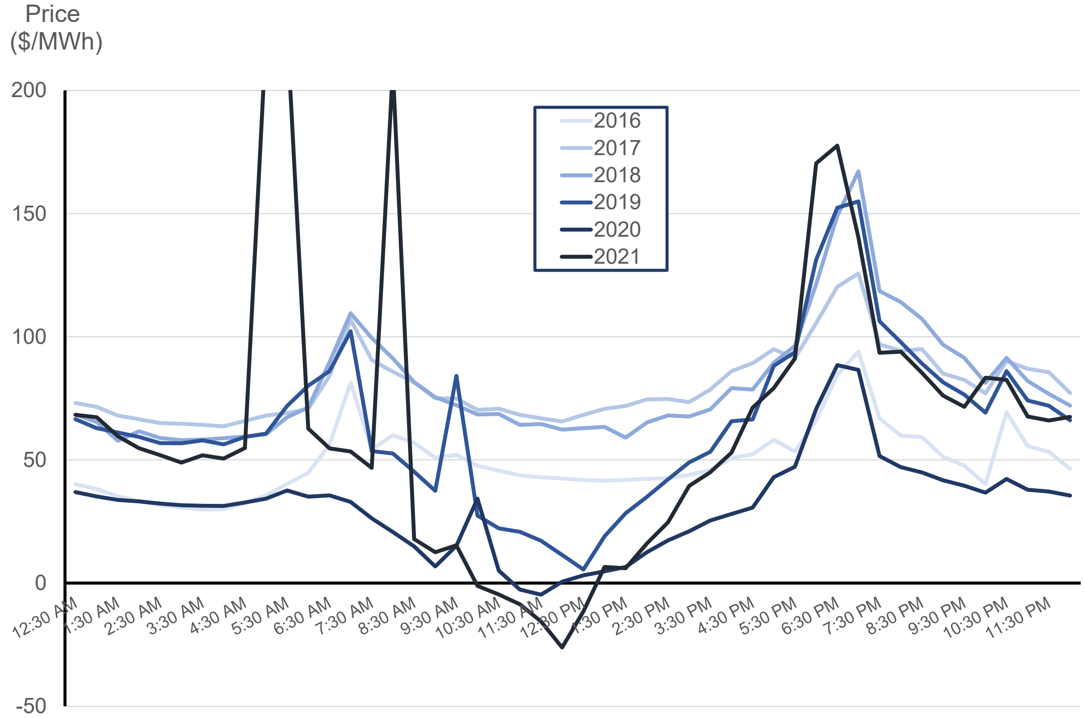
Figure 3: Queensland final demand (grid supplied) Sept 2016-2022



Source: AEMO.

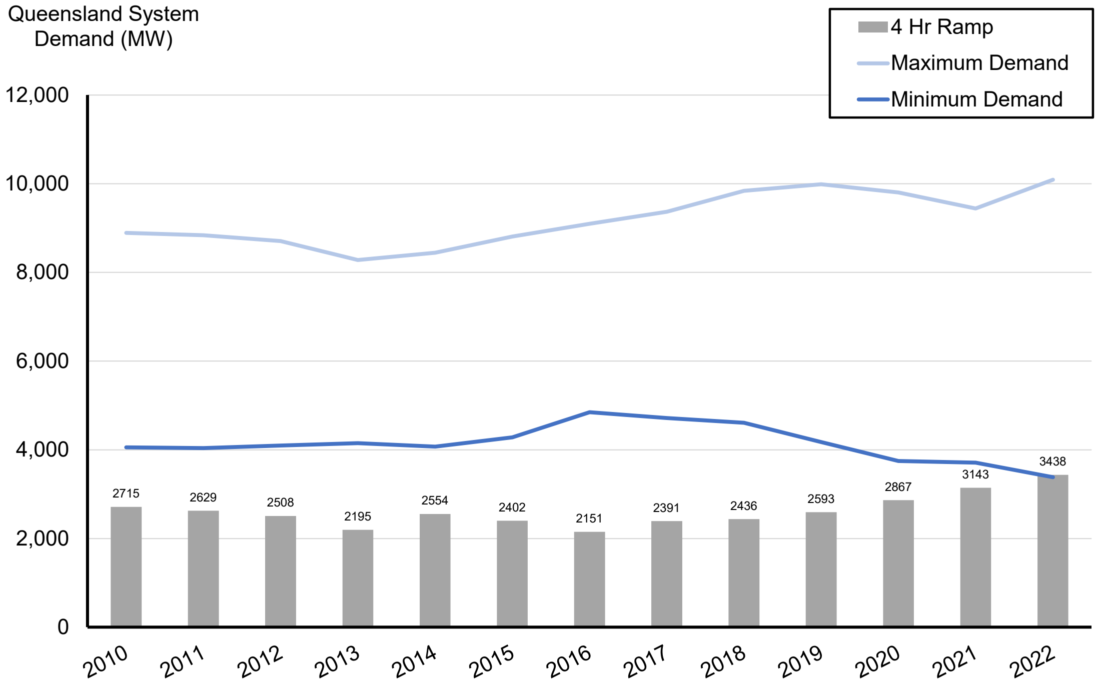
The most concerning aspect of Fig.3 is that unlike other solar-rich power systems such as California, the resources driving the Queensland duck curve are mostly non-scheduled and therefore non-controllable – spread across ~750,000+ rooftops. Note in Fig.3 that daytime load has reduced significantly below the historic off-peak load point of 4am with the most acute impact occurring on Sundays. This *minimum demand problem* has led to a similar pattern of relative prices.

Figure 4: Queensland average spot price (Sept/Oct) and negative price events



Ironically, Queensland peak demand continues to rise whilst simultaneously minimum demand is declining (Fig.5, line series). As a result, the ramping of generators over a 4-hour period is increasing over time (Fig.5, bar series).

Figure 5: Queensland minimum and maximum demand, and 4-hour ramp



The minimum load problem gives rise to two distinct issues for inflexible thermal plant. From an economic perspective, a rising incidence of negative prices is predictable and likely to drive financial distress of the marginal coal plant. From a technical perspective, the minimum load problem requires ever increasing interventions by the market operator.

With the benefit of hindsight, remediation appears straightforward. In the short run, install rooftop solar PV with field devices capable of curtailing output, and in the long run, exiting inflexible coal plant with entry dominated by flexible gas turbines and batteries (the latter helpfully adding to minimum loads when charging).

In Queensland, larger rooftop systems (10kW+) are now required to couple field devices upon installation, which facilitates remote curtailment. But the political economy of applying such a policy to all new installations is surprisingly complex, and the transaction costs associated with retrofitting the existing 750,000+ rooftops or part thereof is prohibitive.

To summarise, the combination of inflexible thermal plant and rapidly declining minimum loads through rising rooftop solar PV will invariably impact the operation of the market itself. The non-continuous and unpredictable nature of minimum load events, 'must run' requirements of inflexible coal plant, and the (profitable) requirement of evening production duties by dispatchable plant means feasibility issues are likely to emerge. The nature of these problems is most likely to cause primal infeasible issues within the mathematical programming methods employed to solve energy market dispatch intervals.

3. Overview of ANEM Model and Data

Our 'ANEM Model' is an agent-based structural model of a power system. The agents include demand- and supply-side participants as well as an Independent System Operator (ISO) who operates and clears the market. Nodes and transmission line network structures collectively constrain the behaviour of all agents.

3.1 ANEM Model

The methodology underpinning the ANEM Model involves the operation of wholesale power markets by an ISO using Locational Marginal Pricing (LMP). ANEM is a modified and extended version of the American Agent-Based Modelling of Electricity Systems (AMES) model developed in (Sun and Tesfatsion, 2007, 2010), and programmed in Java using Repast java toolkit (Repast, 2023; Tesfatsion, 2023). Key features include transmission network pathways, competitive dispatch of generation technologies with price determination based upon marginal costs and branch congestion characteristics, along with intra- and inter-state trade.

A Direct Current Optimal Power Flow (DC OPF) algorithm is used to jointly determine optimal dispatch of generation plant, power flows on transmission branches and wholesale prices. The following unit commitment features are accommodated:

- marginal generation costs;
- capacity (MW) limits applied to both generators and transmission lines;
- generator ramping constraints;
- generator start-up costs; and
- generator minimum stable operating levels.

Modelling methods used in this article on the minimum load problem are qualitatively similar to the Over-Constrained Optimisation Methods used by the Australian Energy Market Operator in the NEM's dispatch algorithm (AEMO, 2011, 2017). However, the underlying structure of our wholesale market model and the NEM's dispatch algorithm are different and address quite different structural issues. In particular, our model has a more disaggregated network structure based on a nodal framework. Moreover, our model co-optimises dispatch and both inter- and intra-regional transmission power flows (the market's algorithm co-optimises dispatch and inter-regional transmission branches).

3.2 DC OPF solution algorithm used

Optimal dispatch, wholesale prices and power flows on transmission lines are determined in the ANEM model by a DC OPF algorithm developed in Sun and Tesfatsion (2010). The (Mosek, 2023)[3] optimisation software that exploits direct sparse matrix methods and utilises a convex quadratic programming algorithm based on the interior point algorithm is used to solve the DC OPF problem. Equation 1 highlights the implementation of the DC OPF algorithm's objective function, equality and inequality constraints.

The ANEM model solves the optimisation for each half-hourly dispatch interval. Equation 1(a) shows the objective function that minimises real-power production levels P_{Gi} for all generators i = 1,…,I, and voltage angles δ_k for all transmission lines k = 2,..,K subject to the constraints in Equation 1(b), 1(c) and 1(d).

Equation 1:ANEM's objective function and constraints

(a) *Objective function: Minimise generator-reported marginal costs and voltage angle differences*

$$\sum_{i=1}^{I}\left[A_i P_{G_i} + B_i P_{G_i}^2\right] + \pi\left[\sum_{I_m \in BR}\delta_m^2 + \sum_{km \in BR,\, k\geq 2}\left[\delta_k - \delta_m\right]^2\right],$$

where:
i = generator number
P_{Gi} = real power (MW) production level of generator i
k = transmission line number
δ_k = voltage angle (in radians) at node k

(b) Constraint 1: Nodal real power balance equality constraint

$$0 = PLoad_k - PGen_k + PNetInject_k$$

where:

$PLoad_k = \sum_{j \in J_k} P_{L_j}$ (i.e. aggregate power take-off at node k, e.g. demand)

$PGen_k = \sum_{i \in I_k} P_{G_i}$ (i.e. aggregate power injection at node k, e.g. generation)

$$PNetInject_k = \sum_{km \text{ or } mk \in BR} F_{km}$$

$$F_{km} = B_{km}\left[\delta_k - \delta_m\right]$$

(i.e. real power flows on branches connecting nodes 'k' and 'm')
k = 1, …, K

$\delta_1 \equiv 0$, a normalisation constraint.

(c) Constraint 2: Transmission line real power thermal inequality constraints

$F_{km} \geq -F_{km}^{UR}$, (lower bound constraint: reverse direction MW branch flow limit)

$F_{km} \leq F_{km}^{UN}$, (upper bound constraint: normal direction MW branch flow limit),

where:
$km \in BR$, transmission branch km is an admissible transmission branch interconnecting nodes k and m.

(d) Constraint 3: Generator real-power production inequality constraints

[3] Mosek version 6 was used within the ANEM model to obtain the results reported in this paper.

$P_{G_i} \geq P_{G_i}^{LR}$, (lower bound constraint: lower half-hourly MW ramping limit)

$P_{G_i} \leq P_{G_i}^{UR}$ (upper bound constraint: upper half-hourly MW ramping limit),

where:

$P_{G_i}^{LR} \geq P_{G_i}^{L}$,

(lower half-hourly ramping limit $\geq$ lower MW capacity limit)

$P_{G_i}^{UR} \leq P_{G_i}^{U}$

(upper half-hourly ramping limit $\leq$ upper MW capacity limit)

i = 1,…,I.

Note that "U" and "L" denote upper and lower limits, A_i and B_i are linear and quadratic cost coefficients from the generator's variable cost function. δ_k and δ_m are the voltage angles at nodes 'k' and 'm' (measured in radians). Parameter π is a positive soft penalty weight on the sum of squared voltage angle differences. Variables F_{km}^{UN} and F_{km}^{UR} are the (positive) MW capacity limits associated with real power flows in the 'normal' and 'reverse' direction on each connected transmission branch km ∊ BR. Matrix B_{km} is negative susceptance matrix (Sun and Tesfatsion, 2010).

The linear equality constraint refers to a nodal balance condition which requires that at each node, power take-off by the demand side equals power injection (by generators located at that node) and net power transfers from other nodes on 'connected' transmission branches. On a node-by-node basis, the shadow price associated with this constraint gives the spot price associated with that node. Accounting for power flows in the equality constraints of the DC OPF algorithm allows the incorporation of congestion components in regional wholesale spot prices, which can produce divergence in regional spot prices associated with congestion on transmission branches.

The linear inequality constraints ensure that real power transfers on connected transmission branches remain within permitted 'normal' and 'reverse' direction MW transfer limits and the real power produced by each generator remains within permitted lower and upper MW capacity limits while also meeting MW ramp up and ramp down generator production limits. For those interested in the transmission grid characteristics and the calculation of transmission losses, a summary appears in Appendix III.

3.3 Data: general use of NEM planning assumptions

Our base model assumptions relating to ($/GJ) fuel cost, ($/MWh) Variable Operation and Maintenance (VOM) costs, ($/MW/year) Fixed Operation and Maintenance (FOM) costs, minimum and maximum MW capacities, emission intensity rates, auxiliary load rates and plant closures were sourced from the Australian Energy Market Operator's (AEMO, 2022) biannual Integrated System Plan or 'ISP' assumptions and scenarios workbook v3.4 dated June 2022'.[4] Specifically, for existing and new entrant generation as well as demand profiles, we follow the AEMO assumptions for the 2022 ISP associated with their so-called '2030 step-change' scenario. While the model simulates the entire NEM, our model results focus specifically on the Queensland region – being of significant interest and the centre of gravity vis-à-vis *the minimum load problem*.

To summarise the data, maximised dispatched MW capacities and energy output by technology type for Queensland and the entire NEM are listed in Tables 1-2.[5] It should be recognised that the data listed in Tables 1-2 are for our *base case* (Scenario A), which is explained in detail in the next

[4] All data is available at: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

[5] Note, in this context, that maximised dispatched capacities comprising the data in Table 1 could well be lower than the generation plant's maximum MW nameplate capacities.

Section. For now, Scenario A contains coal generation and the largest number of dispatch intervals requiring feasibility repair of the modelled scenarios.

From inspection of Tab.1 it is apparent that Queensland has a significant portfolio of coal and Combined Cycle Gas Turbine (CCGT) assets within the NEM. Both technologies have non-zero minimum stable operating levels which drive feasibility issues within the wholesale electricity market under 'low load, high renewables' conditions.

Queensland also has a significant existing Open Cycle Gas Turbines (OCGT) fleet that is well suited to meeting peak demand events. Forecast levels of wind and solar capacity equate to 7900MW and 3400MW respectively. Queensland is also anticipating significant (c.2000MW) pumped-hydro and utility-scale battery capacities located in Northern and Southern Queensland. The forecast of rooftop solar PV for 2030 in Queensland is 7,000 MW, up from the current 5,000MW[6] and slightly behind the capacity forecasts for the adjacent New South Wales (NSW) region.[7]

Finally, the maximum half-hourly peak demand for Queensland in the step-change scenario for 2030 is 11,300 MW. This compares to Queensland's existing peak of 10,000MW and the (diversified instantaneous) NEM-wide peak of 36,750 MW.

Table 1: Generating capacity and peak demand for Queensland and the NEM

Technology	NEM total	QLD total
Black coal	12,000	7,300
brown coal	1,200	0
CCGT	3,700	1,500
OCGT	9,300	1,500
Wind	30,000	7,900
Solar (utility scale)	11,300	3,400
Conventional Hydro	5,300	130
Pumped Hydro	9,000	3,000
Batteries (utility)	6,700	1,800
TOTAL	88,500	26,530
Rooftop Solar PV	25,000	7,000
Peak Demand	36,750	11,300

In Table 2, base case results from our model vis-à-vis energy generated by technology type is listed for Queensland and the entire NEM. By way of brief background, NEM coal plant marginal running costs range from $10-$60/MWh while CCGT and OCGT plant are typically leveraged to ~$9/GJ gas costs, meaning marginal running costs of ~$65/MWh and ~$100/MWh, respectively.

[6] The data used has the identifier 'PV_TOT' in the AEMO 2022 ISP demand database.
[7] This data is available under the heading 'demand trace data – regional files', contained at: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios. NSW was projected to have behind-the-meter 2030 rooftop solar maximum capacity of 8211 MW's.

From inspection of Tab.2 it is evident that significant energy is produced by coal and CCGT generation assets in Queensland. Queensland grid-supplied energy demand of 55,600 GWh associated with the 2030 step-change scenario can be compared to the equivalent NEM-wide energy demand of 184,000 GWh. Note this demand is a net concept associated with centralised operational demand. To determine total final energy demand, operational demand and distributed rooftop solar PV output must be added, along with storage loads from pumped-hydro and batteries, and transmission losses determined within the model.

Energy generated in Queensland by rooftop solar is projected at 15,000GWh, the third largest contributor after coal and wind generation. Interestingly, the sum of rooftop and utility-scale solar in Queensland equates to 19,200 GWh, thus resembling the contribution from wind generation at 22,600GWh.

Table 2: GWh by technology for Queensland and the NEM

Technology	NEM total	QLD total
black coal	70,000	40,000
brown coal	8,100	0
CCGT	13,000	6,000
OCGT	4,300	250
Wind	87,300	22,600
Solar (utility Scale)	14,500	4,200
Conventional Hydro	1,500	0
Pumped Hydro	3,80	500
Batteries (utility)	1,500	250
Total Generation	200,200	73,800
Rooftop Solar PV	49,000	15,000
Energy Demand (Operational)	184,000	55,600

3.4 Modelling pumped hydro and batteries

The energy contribution of pumped hydro and utility-scale batteries are moderate at 500GWh and 250GWh, respectively (Tab.2). This outcome reflects the relatively large operational coal generation fleet in Queensland under the base case scenario, which *crowds-out* opportunities for both pumped-hydro and batteries to be frequently dispatched. Axiomatically, coal plant exit changes these results considerably.

Pumped-hydro and battery technologies undertake a nuanced role in the market given their ability to absorb otherwise 'excess output' from intermittent solar PV and wind generation. In the NEM, the typical diurnal cycle of wind is biased to the night-time and solar PV has a day-time bias.

In the modelling, pumping or charging loads of both pumped-hydro and batteries were targeted towards periods where the underlying variable renewable resources were sufficient to supply both underlying aggregate demand as well as additional demand created through pumping or charging loads. Implementation of pumping/charging loads were triggered when the proportion of VRE available for dispatch in a given dispatch interval was at least 50% (for pumped hydro) and 70%

(for batteries) of the relevant nameplate VRE MW capacity. At these thresholds, part-load pumping or charging occurs and ratchets-up to full load levels at higher VRE thresholds.

By linking pumping and charging loads to periods of high VRE resource availability, it is more likely that sufficient generation output will be available to meet aggregate underlying demand and storage loads, thus minimising the potential incidence of higher wholesale electricity prices at the margin.[8] Pumping/charging of these resources also facilitates increased power from wind and solar generation plant and reduces curtailment or *'spill'*.

It should be noted that the lower threshold applying to pumped hydro plant reflects higher demand for storage from such assets (cf. batteries). In practical terms, this generally means that pumping loads occur during the periods:

- 11pm to 5.30 am (when excess wind exists); and
- 10 am to 3.30 pm (when excess solar exists);

For batteries, the equivalent charging periods typically arising are:

- Midnight to 4 am; and
- 10 am to 3 pm.

To be clear, pumping and charging loads would typically not occur over morning or evening peaks and in the period leading towards midnight because the diurnal cycle of wind generation is weaker.

In the model, pumped-hydro and battery supply offers generally fall between coal and open cycle gas plant, targeting a balancing roll but with a competitive advantage conferred relative to peak load OCGT technologies. This strategy has two facets: (1) it maximises the roll that storage technologies can contribute to system balancing; and (2) determining the minimum sizing of gas generation capacity that might still be needed for system balancing, notwithstanding the enhanced role that is being played by pumped hydro and battery storage in this area as well.

4. Salient features of 'feasibility repair'

Our modelling seeks to identify the frequency of critical minimum load events. During these episodes, the dispatch algorithm becomes intractable because of extremely low grid-supplied loads and a prevalence of inflexible generation plant seeking to dispatch at their 'must run' minimum stable loads when a clear oversupply exists. We refer to these dispatch intervals as *'feasibility repair'* intervals. Once identified, we proceed by examining increasing rates of coal plant closures to identify what level is technically, and economically, inevitable given the ongoing surge in new VRE capacity.

Queensland's coal fleet currently comprises 8100MW of generating plant. Between now and 2030, our base case assumes the closure of only one coal plant 700MW (i.e. Callide B power station). The coal fleet in New South Wales currently comprises about 10,350MW and our base case for 2030 assumes ~5000MW of coal plant closures (i.e. Liddell and Eraring power stations).

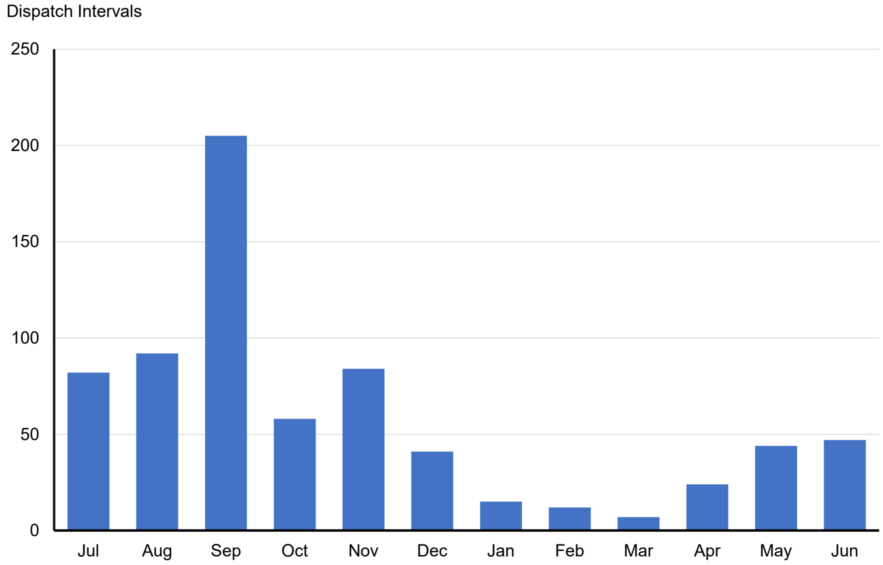
Our base case commences as the highest level of coal capacity in service, at 13,200MW in aggregate (nb. including 1200MW of brown coal in the Victorian region). Our studies then focus on exiting two marginal coal plants in Queensland and New South Wales – the 1600MW Gladstone and 1320MW Vales Point power stations, respectively.

When our model runs for the 2030 year at 30-minute resolution under the base case scenario, we find a total of 711 feasibility repair intervals. That is, the model experiences 711 intractable half-

[8] A key rationale for the above approach is that the higher the amount of renewable energy available for dispatch, the lower will be the resulting spot price, *ceteris paribus*.

hourly dispatch intervals in the base case. The timing of the incidence of feasibility repair dispatch intervals (by month) from the model is presented in Figure 6.

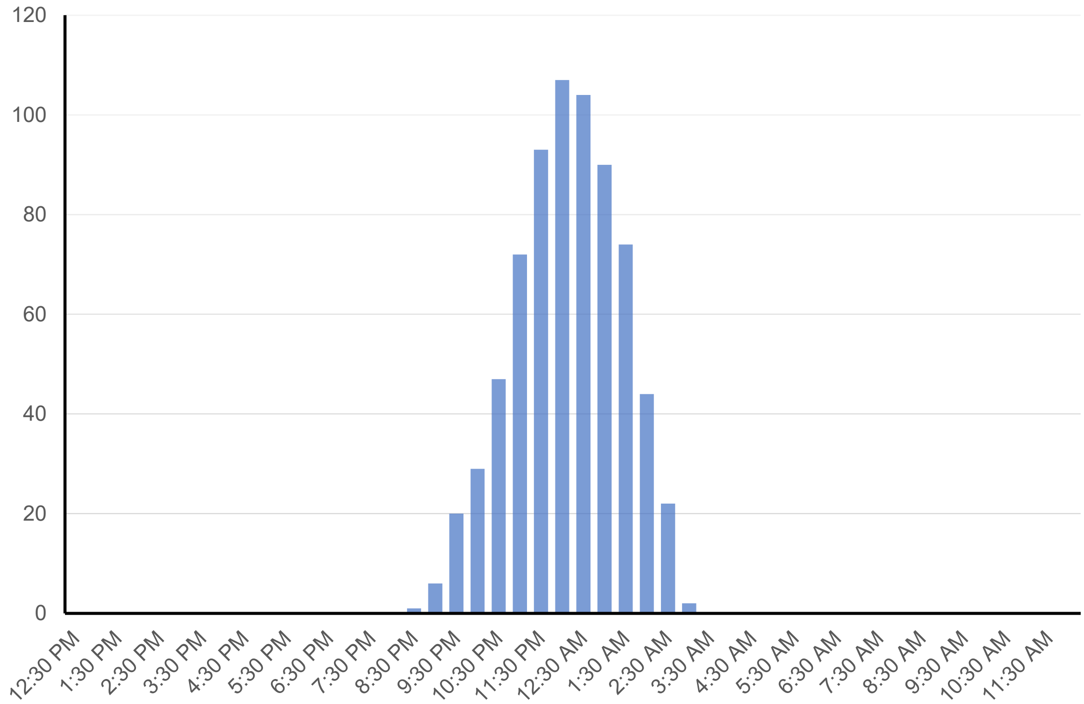
Figure 6: Incidence of feasibility repairs by month (2030)



Examination of Fig.6 reveals that *feasibility repairs* primarily occur during spring (September 205 intervals, November 84 intervals) and winter (August 92 intervals, July 82 intervals). There are notably more intervals over the period July to November. The lowest values occur during the NEM's peak demand quarter, Jan-Mar. Finally, it is worth noting that dispatch intervals requiring feasibility repair occur across all months.

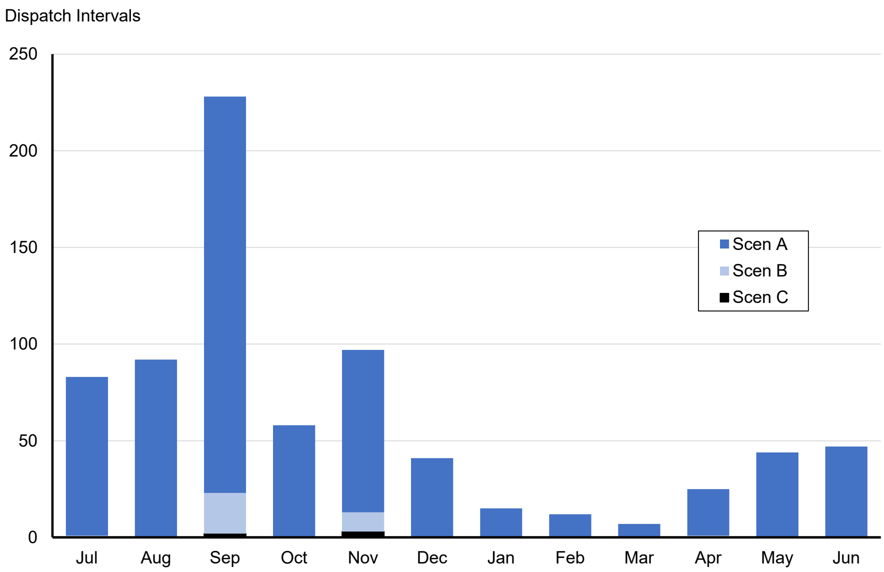
Figure 7 plots the incidence of feasibility repair intervals by time-of-day. Feasibility repairs are concentrated during daylight hours, centred either side of 12:00pm with no incidences during overnight periods.

Figure 7: Repairs by time of day



In order to gauge the incidence of feasibility repair intervals vis-à-vis operating coal plant capacity, we compare our base case (labelled Scenario A, dark blue bars) with a scenario in which the two marginal coal plants in Queensland (1600MW Gladstone) and New South Wales (1320MW Vales Point) exit the market (labelled Scenario B, light blue bars). Output from these coal generators is replaced by renewable and gas generation, and in order to ensure reliability criteria is met in Queensland following the loss of 1600MW, an additional 800MW of dispatchable plant (viz. gas turbines, batteries, pumped hydro) is commissioned. Average prices increase from $35/MWh (Scenario A, which exhibits very material merit order effects) to $67/MWh (Scenario B). These prices shadow supply offer prices of coal plant in Scenario A, increasing to the lower bounds supply offers associated with dispatchable capacity from pumped-hydro, batteries and gas turbines in Scenario B. Scenario C (black bars) deducts an additional 350MW coal unit in Queensland (from Stanwell power station).[9] Results are presented in Fig.8 on a 'stacked basis'.

Figure 8: Total incidence of feasibility repairs by month and scenario



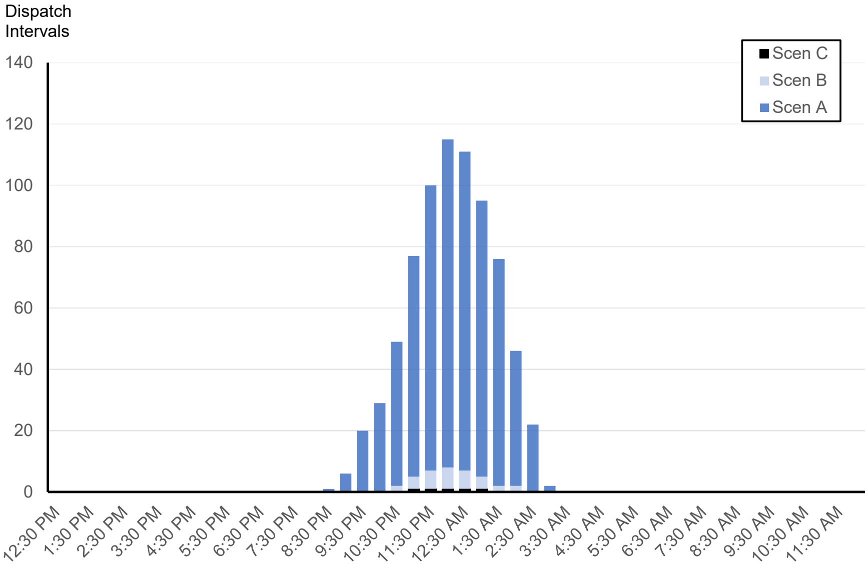
The first major outcome that we identify in Fig.8 is a very material reduction in half-hourly dispatch intervals requiring feasibility repair in Scenario B through the exit of the 1600MW Gladstone and 1320MW Vales Point coal plants (i.e. reduces by the dark blue bars). The closure of a 350MW unit in Scenario C further reduces the incidences of intractable dispatch which appear in September and November, suggesting transient unit de commitment may be sufficient. To summarise Fig.8 -

- The total number of repair half-hour intervals in Scenario C = 5,
(3 intervals in November and 2 in September)
- The total number of repair half-hour intervals in Scenario B = 33
(21 intervals in September and 10 in November)
- The total number of repair half-hour intervals in Scenario A = 711

Fig.9 plots the incidence of feasibility repairs by half-hourly dispatch interval for each Scenario. Consistent with the from Fig.7, feasibility repairs were centred either side 12.00pm, with particular concentration around the 11 am to 1 pm time-period.

[9] Two additional scenarios investigate 1-2 units at Tarong power station in Queensland. In both cases, no incidence of feasibility repair was observed and so no further consideration of those scenarios was undertaken. h

Figure 9: Total incidence of feasibility repair intervals



From these model results we may conclude the following:

- The incidence of feasibility repairs was directly linked to an oversupply of inflexible coal plant. Scenario A included the highest level of operational coal plant capacity and had the highest incidence of feasibility repairs. This tapered off with coal plant closures.

- The greatest extent of feasibility repairs occurs in the months of July, August, September and November. October exhibits a curiously lower incidence likely related to increased maintenance activity during that month.[10]

- The lowest number of feasibility repairs occurs over summer when household air conditioning loads are at their peak.

- Feasibility repairs are centred over the half hour 12pm. This links feasibility issues with episodes of the minimum load problem.

- All feasibility repairs occurred during daytime – none emerged overnight or during morning and evening peak periods.

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5. The anatomy of constraint violations

Recall that in our model, feasibility repair involves constraint relaxations to secure primal and dual feasible solutions that are not forthcoming under original constraint settings. In Section 4, we observed feasible repair intervals tended to be concentrated around 12:00pm. We also suggested in Section 4 that the nature of constraint violations, given those patterns, were likely to be produced by emergent duck curve effects where rooftop solar naturally diminishes grid-supplied demand, posing problems for solving the wholesale market when inflexible coal generation plant dominates the (dispatchable) aggregate supply function.

Coal plant non-zero minimum stable load combines to ensure centralised demand is frequently insufficient to satisfy the minimum 'must-run' requirements of the available coal fleet during repair intervals. In practice, the early warning signs of this will be a gradual increase in the frequency and

[10] Stanwell 4, Condamine, Loy Yang B and Tamar Valley CCGT were all assumed to be offline in October for annual maintenance. In contrast, only one unit was assumed to be offline for maintenance in November (Kogan Creek) and only one unit in July (Gladstone 3). Three units were assumed offline in August (Yabulu, Tarong North and Tallawarra) and three units also in September (Millmerran 2, Mt Piper 2 and TGN CCGT).

intensity of negative price events. These events will simultaneously begin to erode the net profit margins and quantities dispatched of inflexible thermal plant. This is well documented in the energy economics literature and comprises a combination of price impression effects (Mills, Wiser and Lawrence, 2012; Nicolosi, 2012; Edenhofer *et al.*, 2013; Hirth, Ueckerdt and Edenhofer, 2016), stochastic production effects (Johnson and Oliver, 2019; Simshauser, 2020) and utilisation effects (Hirth, 2013; Höschle *et al.*, 2017; Simshauser, 2018).

Conversely, operational flexibility is likely to become an increasingly valuable plant characteristic. Another potentially valuable characteristic may be higher MW transfer capacities on transmission branches to enhance the ability to shift power around the transmission network by enhancing its geographic reach, and diversity of minimum loads.

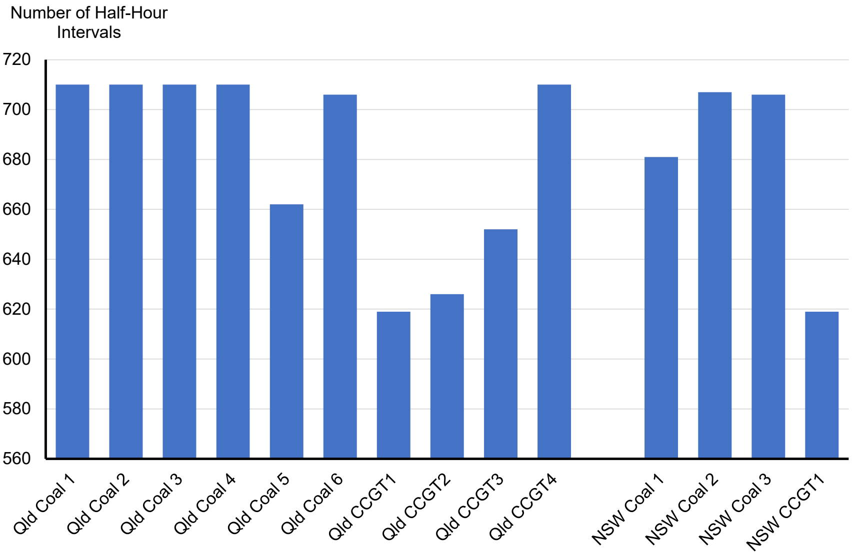
Accordingly, we now turn our modelling efforts to examining the extent to which these factors emerge within constraint violations. Specifically, we investigate the extent that feasibility repair arises as a result of (1) non-zero minimum stable (i.e. must-run) operating levels of coal and CCGT plant; and (2) normal and reverse direction MW transfer capacity limits on transmission lines. On (2), particular attention will be given to investigating the presence of network congestion across the Queensland to New South Wales Interconnector – to clarify whether it is possible to 'export your way out of the problem' – via accessing inter-regional load diversity.

5.1 Non-zero minimum stable load constraint violations

The catalogue of constraint violations for all feasibility repair intervals across coal and CCGT plant are illustrated in Fig. 10. Note in this context, constraint violation would mean that a *lower* constraint was imposed compared to the original constraint setting associated with primal infeasibility. As such, this process would mimic key aspects of greater operational flexibility: (1) the ability to shut-down quickly; and (2) the ability to operate at lower part-load capacities.

The data was collated by assessing if the original constraint settings of the plant listed in Fig. 10 were violated during a feasibility repair interval. The results for each plant was collated across the 711 feasibility repair intervals associated with Scenario A.

Figure 10: Constraint violations for coal and CCGT by power station (half-hour count)



The first point to note from Fig. 10 is the large number of affected plant located in Queensland compared to NSW. But ultimately, all black coal and CCGT plant in both regions are affected. Second, CCGT units were principally aligned to supplying power during the morning and evening peak periods, thus had lesser exposures to feasibility repair. Finally, there is some variability across, and within, coal plants. For example, Queensland Coal Plant #5 experienced considerably less constraints than the other coal plants. And while not visible through inspection of Fig.10, Queensland Coal Plant #1 comprises 4 x 350MW units, and of these, one unit experienced only 200 half-hour intervals of constraints whereas the remaining 3 units were impacted in all 711 dispatch intervals. These variations reflect planned overhauls or forced outages had coincided with elevated episodes of feasibility repair (i.e. primarily during the spring maintenance season).

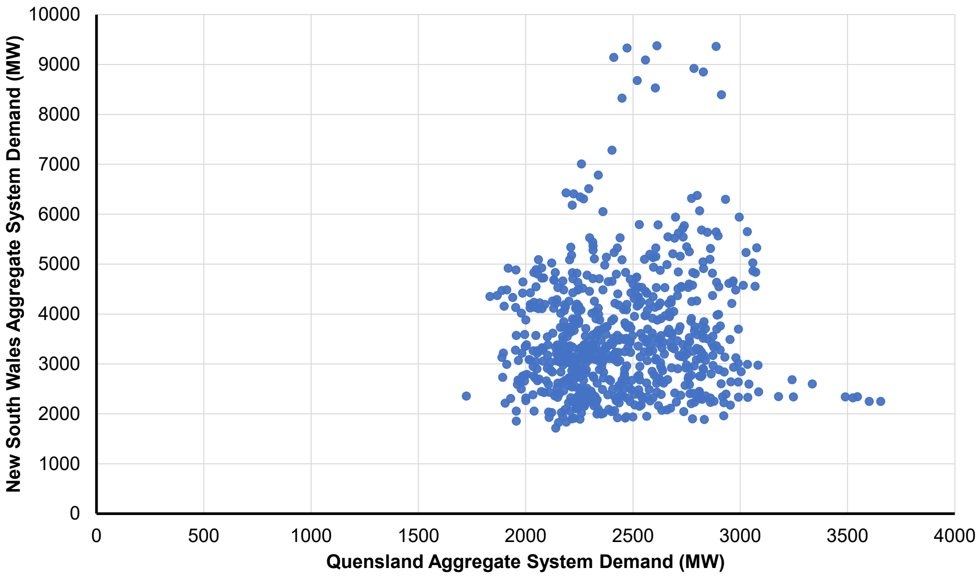
To summarise, we can confirm the source of the problem is the combination of low grid-supplied demand and the presence of inflexible thermal plant unable to lower their minimum stable loads.

5.2 Queensland to New South Wales Interconnector

One logical line of inquiry is to test whether a state like Queensland can *export* its way out of trouble during dispatch intervals requiring feasibility repair. This requires an examination of underlying demand conditions as well as transmission network properties and flows during feasibility repair events.

Fig.11 presents a scatter plot of operational demand[11] in Queensland (x-axis) and New South Wales (y-axis) during feasible repair intervals under Scenario A. Note the tighter demand range prevailing for Queensland relative to New South Wales, with Queensland low loads falling between 1720 – 3600MW and New South Wales falling between 1720 – 9400MW (noting state peak demands are 11,300MW and 14,600MW, respectively). Examination of Fig. 11 reveals sizeable concentrations of scatter points encompassing coincident minimum loads, viz. below 4000MW in New South Wales and below 3600MW in Queensland.

Figure 11: Qld and NSW system demand during QLD minimum load events

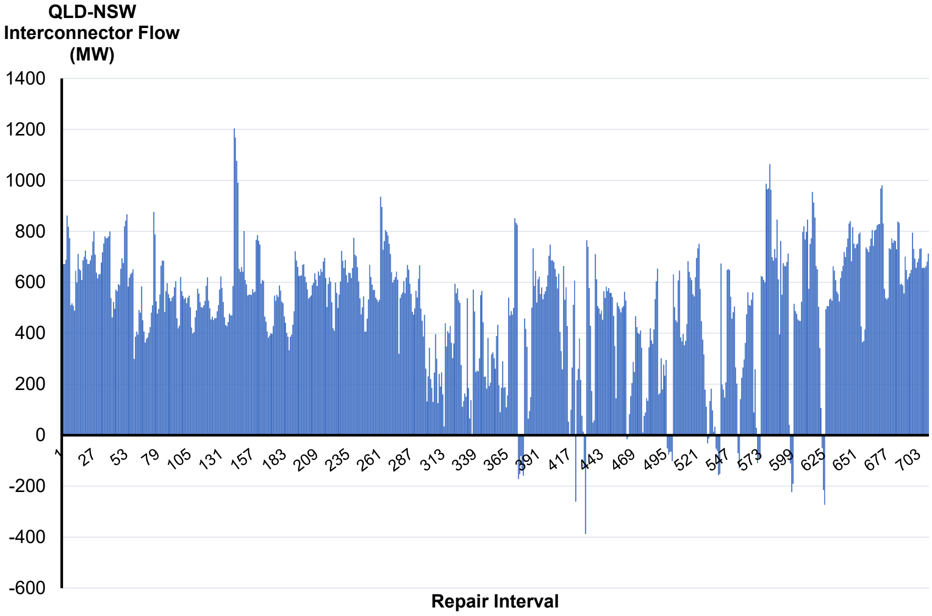


The other crucial factor that may impact Queensland's ability to export power to the adjacent region is whether the interconnector to New South Wales (or any other critical branch in southern Queensland) experiences congestion during minimum load events. Fig. 12 depicts power transfers on the main Queensland to New South Wales Interconnector, which is currently a double circuit 330 kV transmission line and an assumed second circuit[12], meaning a southerly flow limit of 1,700 MW. Fig.12 tends to suggest the 'exporting your way out' of the minimum load problem is not viable – exports across the interconnector peak at 1200MW, well below the 1700MW limit. Evidently, the minimum load problem is a largely simultaneous matter affecting both regions.

[11] Step-change scenario operational demand data developed by AEMO as part of the 2022 ISP process.

[12] In the modelling, an N-1 assumption was employed where we excluded one of the 330 kV circuits. As such, the combined capacity of QNI was assumed to be based around three operational 330 kV circuits.

Figure 12: Interconnector Flows during QLD minimum load events



6. Policy implications and concluding remarks

In this article, we examined a new frontier emerging in the NEM's Queensland region, *the minimum load problem. T*he origins of the minimum load problem are the hollowing out of daytime grid-supplied load (cf. aggregate final demand) during high solar irradiation and mild weather conditions combined with an oversupply of inflexible coal plant. The situation in Queensland differs in subtle ways from other variants of the so-called 'duck curve' effect in that the source of the problem comes from non-scheduled (small-scale) rooftop solar PV, large parts of which are uncontrolled and therefore non-curtailable. Production inflexibility of legacy coal generation plant forms the other limb this emerging problem.

Our results suggest ~700 half-hour intervals per annum in which *the minimum load problem* becomes binding. Feasibility repairs were required throughout the year but were heightened in the winter and spring months of July, August, September and November. The minimum load problem was centred around 12 noon. The interconnector to the adjacent region of New South Wales could not be expanded to 'export your way out of the problem'.

At a strategic level, if a feasible solution to the wholesale electricity market cannot be attained then spot price and generation dispatch schedules cannot be posted. In these circumstances *and without feasibility repair*, the wholesale electricity market would experience gross malfunction – in essence, the market would become broken. Fundamentally, the only viable option in our modelling was the exit of coal plant – temporarily, or more likely, permanently given net zero targets. What implications this may have for system strength is a matter for engineering studies.

The troubling aspect of our modelling, which may understate the nature of the present problem, is that our assumptions book included a new 2000MW pumped hydro project that is currently unlikely to enter into service prior to 2030. This means the problem becomes larger, sooner. Furthermore, the minimum load problem is one that continuously deteriorates over time. In practical terms, this means the development of a fleet of new entrant, flexible, dispatchable plant to replace ageing inflexible legacy coal plant is rather urgent.

What can other potentially solar-rich jurisdictions with inflexible thermal generation fleets learn from Queensland? The first and most obvious policy lesson vis-à-vis the roll-out of rooftop solar PV in large numbers is to ensure appropriate field devices are included during initial installation to allow central coordination (i.e. curtailment) if required for system security purposes. The transaction costs of retrofitting make this quite important.

Second, more thought is required vis-à-vis exit and entry. When energy markets were being designed, and in particular Australia's National Electricity Market during the early-1990s, the problem being solved was oversupply, prices set above efficient levels, state ownership and underperforming generators in an environment of solid demand growth. Market design therefore focused on productive and allocative efficiency, and the dynamic efficiency of entry. There are of course endless streams of literature on market design vis-à-vis market efficiency, and notions of efficient entry (for a useful survey of the literature, see Bublitz et al., 2019).

To the best of our knowledge, little policy thought was given to exit. Discussions of plant exit while governments were privatising their power assets would send mixed signals to potential buyers. Yet exit is now an important issue and the NEM's recent history of coal plant closures has been anything but smooth (see Nelson et al., 2018; Dodd and Nelson, 2019; Rai and Nelson, 2020; Nelson et al., 2022; Simshauser and Gilmore, 2022)

Our analysis tends to suggest that the exit of inflexible coal plant in the presence of sharply rising levels of intermittent renewables must be carefully orchestrated, particularly given the proliferation of a vast fleet of non-scheduled (and therefore uncontrollable) rooftop solar PV. While not the focus of their work, Hardt et al., (2021) examine the technical problems encountered from a system strength perspective.

Sudden exit requires the rapid entry of flexible plant, including batteries, gas turbines and pumped hydro plant absent a large, pliable and highly elastic demand-side response. The demand-side has long been the underperforming element of the wave of energy market reforms commencing in the 1990s (see Batlle and Pérez-Arriaga, 2008; Cramton and Stoft, 2008; Finon and Pignon, 2008; Roques, 2008; Bublitz et al., 2019). Queensland has witnessed a decade-long solar revolution along with deteriorating midday prices (per Fig.4) and we are not aware of any material change in power system load as a response. What we have observed is the trends and patterns outlined in Figures 3-5, namely falling minimum loads, ongoing rises in peak demand, an ever-growing ramp rate requirement, an aging coal fleet (with increasing outage rates), and a sharp rise in the incidence of negative prices which does not bode well for inflexible plant.

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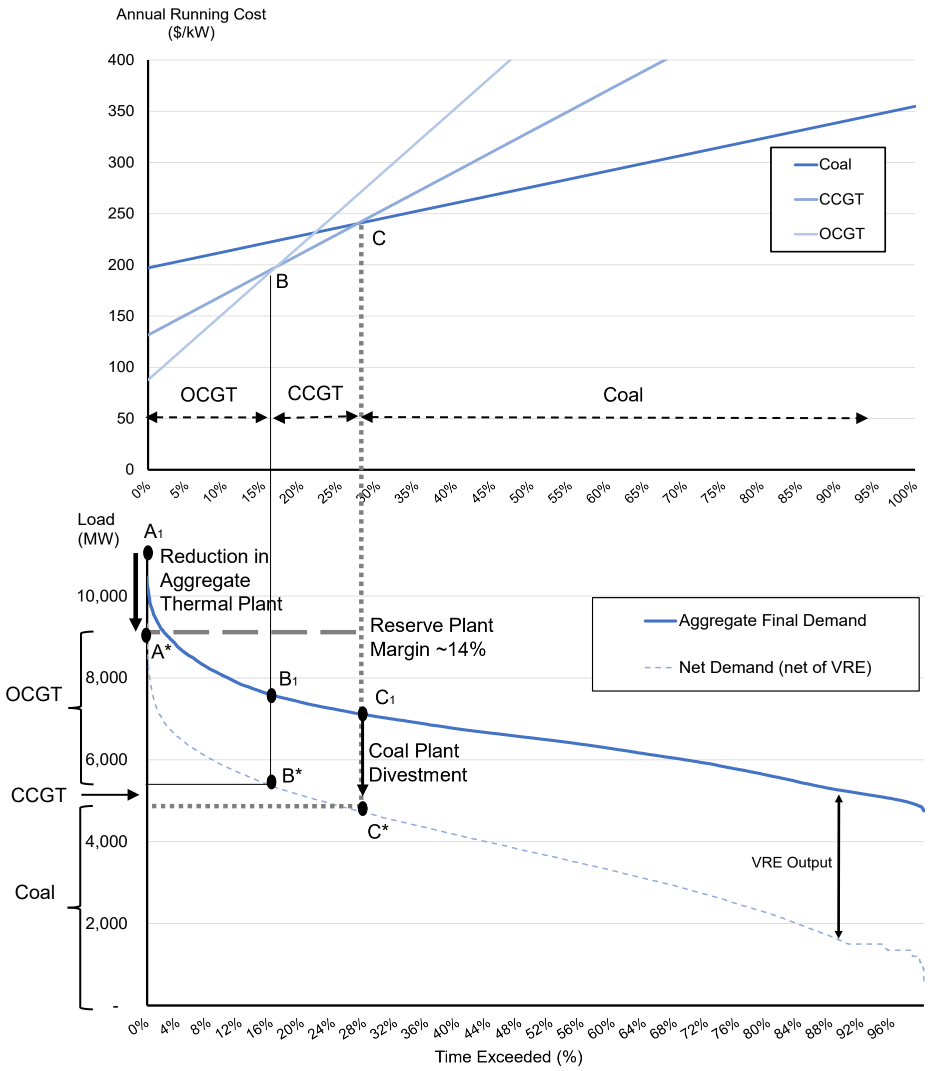
Appendix I: Static partial equilibrium analysis



Appendix II: ANEM Model Detail

The transmission grid utilised in the ANEM model is an AC grid modelled as a balanced three-phase network defined according to the design features outlined in Sun and Tesfatsion (2010). The following inter-state interconnectors link the NEM's five zones:

- QLD-NSW-Interconnector (line 11) and Directlink (line 14) links QLD and NSW;
- Tumut-Murray (line 41), Wagga-Dederang (line 43) and Buronga-Red Cliffs (Regional Victoria) (line 46) link NSW and VIC;
- Heywood (line 58) and Murraylink (line 64) link VIC and SA; and
- Basslink (line 57) links VIC and TAS.

In addition, the following ISP actionable transmission augmentation relevant to our analysis was included the modelling:

- QNI major augmentation of the QNI Interconnector linking QLD and NSW (SWQ-Armidale-Tamworth) and Tamworth-Bayswater transmission pathways;

Appendix III: Modelling Transmission Losses

Transmission losses associated with power flows on transmission branches were determined by the DC OPF solution and were calculated for each transmission branch using the methodology outlined in (AEMO, 2012, Section 5). That is, transmission losses are calculated by multiplying the square of the power flow on each transmission branch determined by the DC OPF solution by that branch's line resistance and a factor of proportionality associated with conversion of line current to real power in a three-phase electrical system. These losses are allocated as fictitious nodal demand to the receiving end node – that is, to the node that the power is flowing on the transmission branch towards. The key impact of this operation is to ensure that enough power is generated by generators to both cover transmission losses as well as meeting native demand offtake at each node.