Are gas turbines 'bankable' in transitioning energy-only markets?

Paul Simshauser[♦] [♣]
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Abstract

From their inception, the energy-only electricity market design has been characterised by policymaker concerns of resource adequacy. Spot market price ceilings set too low and lacking a clear nexus with reliability criteria, capricious regulatory interference into otherwise legitimate scarcity pricing events, and a lack of demand-side participation are all thought to make the task of timely entry of requisite reserve plant intractable, and therefore 'un-bankable'. The manifestly random nature of peaking plant spot market revenues are said to have been amplified by the 'merit order effects' associated following the entry of near zero marginal cost intermittent renewables en-masse. Large structural LP utility planning models may produce reliable forecasts of market averages, but struggle to replicate ex ante what will be an energy-only markets' high-end volatility, ex post. The latter frequently underpins entry frictions facing peaking gas turbines. In this article, a stochastic block bootstrapping modelling framework is applied to Australia's energy-only National Electricity Market setting – where the spot market price ceiling does have a tight nexus with the reliability criteria. The market is also characterised by looming coal plant retirements. While reliance on spot market revenues proves problematic for bankability purposes, when combined with cap derivatives from the forward markets, a tractable result emerges, albeit at modest gearing levels. Entry appears more constrained by the pattern of unexpected delays to coal plant closure.

Keywords: renewables, energy-only markets, dispatchable plant capacity.

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

1. Introduction

The primal objective function of energy policy is to minimise power system costs subject to a reliability constraint, and a CO_2 emissions constraint. The reliability constraint is met by an optimal mix of plant including a suitable reserve plant margin. Some peaking plant may run as little as 400 hours per year. Questions over their financial viability are ever present in energy-only markets because generators are paid the spot electricity price only when they produce. There are no administrative side-payments for providing requisite reserve capacity in an energy-only market.

Generation plant is amongst the most capital-intensive of investment commitments across sectors. Consequently, cash outflows are dominated by fixed and sunk costs (including scheduled debt repayments). Project finance – a means by which to maximise debt within the capital structure – is a prominent financing model in the generation sector. As a result, scheduled debt repayments are non-trivial.

[♦] Centre for Applied Energy Economics & Policy Research, Griffith University.
[♣] Energy Policy Research Group, University of Cambridge.

By their nature, peaking plant operate sporadically. Some plant may sit idle for months without earning any spot market revenues whatsoever but are nonetheless needed to maintain the power system in a secure state. Perhaps unsurprisingly, competitive energy-only markets have drawn persistent concerns vis-à-vis 'resource adequacy' – viz. whether an appropriate mix of requisite generation plant capacity will enter on a timely basis. To be sure, the central issue is not whether plant will enter. As imbalances between supply reserves and demand accelerate, a rising frequency (and intensity) of spot price spikes will invariably induce an investment response. The issue is whether a response will be timely.

While such concerns relate to all plant types, peaking plant, historically dominated by the open cycle gas turbine (GTs), are thought to be particularly vulnerable because spot market incomes are *manifestly random*, and therefore '*un-bankable'*. This view can be traced at least as far back as Doorman (2000) and Stoft (2002) and persists to this day (see Bublitz et al., 2019; Neuhoff et al., 2023).

Conditions in *transitioning* energy-only markets (i.e. as intermittent wind and solar PV enter) are thought to make the peaking plant bankability task even harder (Traber and Kemfert, 2011; Liebensteiner and Wrienz, 2020). That is, as near zero marginal cost renewable enter, their output places acute downward pressure on wholesale prices (Bunn and Yusupov, 2015; Gonçalves and Menezes, 2022).

Yet all power system planners consider the GT an indispensable 'last line of defence' in maintaining a power system in a secure state. During episodic periods of very low solar and wind – a common occurrence during winter months – stored energy in batteries can be quickly exhausted. At this point, some form of dispatchable generation without an energy constraint is required. For this purpose, the GT is frequently a least cost option. Their *comparatively* low capital cost (with high marginal running costs) makes GTs ideally suited to peaking duties.

The purpose of this article is to examine the bankability of GTs in an energy-only market. The energy-only market selected in this article is Australia's National Electricity Market (NEM). In the Queensland sub-region, looming requirements for new GTs has been telegraphed, yet only one modestly sized investment proposal (c.400MW) has commitment thus far. For context, the ~11GW // 63TWh Queensland region has the world's highest take-up rates of rooftop solar PV, surging rates of utility-scale solar, wind and short-duration battery deployments, and a crucially, a large and aging fleet of coal-fired generators with several (i.e. ~2400 MW) earmarked for closure over the next five-year window. 400MW of new GTs seems disproportionately low against 2400MW of scheduled (aging) coal retirements.

Given pending coal plant closures, why more GT investment proposals have not emerged is, *prima facie*, somewhat of a mystery. However, in discussion with electricity executives in the NEM, it appears investment screening has been tempered by the use of utility planning models. These structural LP models which date back to the early-1970s are a mainstay of power system planning. However, owing to their data-intensive nature, structural LP models may under-forecast the inherent volatility in energy-only spot markets. Statistical anomalies witnessed in energy-only markets are *very hard to replicate* ex ante. It is to be noted that Australia's NEM is one of the most volatile commodity markets in the world. To assess the bankability of a GT, a more appropriate modelling suite may be required.

In this article, 30-minute (historic) spot electricity price data along with chronologically matched spot gas and electricity futures prices are 'block bootstrapped' to create 10,000 years of (synthetic) historic market data. This has the effect of greatly extending the dynamic highs, lows and cyclicality of an energy-only market setting. The data is then sub-sampled and used to stress test the bankability of a small GT in a large, transitioning energy-only market under conditions of imperfect plant availability.

Block bootstrapping is the crucial addition. As a method, it retains important temporal conditions that inherently exist in energy-only markets (e.g. diurnal patters, solar intensive periods, wind droughts and seasonality are all held in-tact through the sub-sampling process). The analysis then proceeds by deploying a unit commitment model and stochastic valuation model of a GT. Drawing on the principles of Markowitz's portfolio theory, a *'Modified Sharpe Ratio'* (i.e. expected earnings divided by the downside deviation of earnings) helps to identify the GTs optimal portfolio of hedges. And when analysed through this stochastic modelling architecture, the emerging result suggests GT investment is currently tractable in the NEM.

This article is structured as follows. Section 2 presents a brief review of literature. Section 3 presents the models and data used. Sections 4-5 presents model results. Policy implications and concluding remarks follow.

2. Review of Literature

When legacy monopoly electricity systems were restructured and deregulated during the 1980-1990s, two primary electricity market designs emerged:

1. *energy-only markets*, where generators are paid the spot price when they produce, and

2. *capacity and energy markets*, which combines a spot market and a capacity market (the latter designed to cover the onerous fixed and sunk costs of requisite, capital-intensive generation plant).

Both market designs can be shown to theoretically produce broadly the same reliability outcomes (Petitet et al., 2017), but each has pros and cons.

2.1 The problem with capacity and energy markets

Capacity markets can replicate the theoretical efficiency of an energy-only market *if* the administrator determining reserve plant requirements sets all parameters correctly. But as Neuhoff et al., (2016) explain, *details matter*. All too often, capacity planning falls victim to asymmetric information and political intervention, with the likely outcome being the over-procurement of capacity and overinflated total market prices.

A more recent concern with organised capacity markets is their inconsistency with the transition to renewables. Too much of total market revenues are thought to be administratively annexed for conventional generation capacity (Bialek *et al.*, 2021). Furthermore, given capacity and energy markets have lower spot market price ceilings (cf. well-designed energy-only market), smaller intra-day price spreads may constrain storage plant entry below efficient levels (i.e. storage plant are critically reliant on arbitrage revenues[1]). If storage is constrained below efficient levels, renewable curtailment rates will rise above the minimum obtainable, thereby raising renewable entry costs.

Consequently, the energy-only market design is generally taken to be the *theoretically* superior model, viz. due to expected economic efficiency, cleaner price signals, and limited administrative decision-making (see Billimoria et al., 2025). However, there is a long list of assumptions that underpin this theoretical result, meaning in practice the conclusion is not so clear cut.

2.2 The concerns with energy-only markets

As noted in Section 1, risks to timely peaking plant investments in energy-only markets can be traced at least as far back as Doorman (2000). More broadly, entry frictions were first noted by Von der Fehr and Harbord (1995), viz. the capital-heavy nature of power projects (Simshauser, 2018), the indivisibility of plant capacity (De Vries, 2004), long construction lead-times (Clapin and Longden, 2024), investment tenors that span the credit time horizon of capital markets (Offer, 2018) and dynamic inconsistency (see Kydland and Prescott, 1977; Batabyal, 1996) driven by the political uncertainty of future energy policy (Newbery, 2021).

The risk of peaking plant investments emerged as the stronger thematic, however. Peaking plant produce sporadically. Consequently, GT spot market revenues are *manifestly random* (Besser et al., 2002; de Vries, 2003) and therefore ‘un-bankable’ from a debt sizing perspective. Compounding matters – resource adequacy concerns are exacerbated by the price-inelastic nature of large segments of real-time aggregate demand, and the short-run inelasticity of supply given storage is costly (Batlle and Pérez-Arriaga, 2008; Roques, 2008). Indeed these concerns within the early literature remain prevalent to this day (see Fabra, 2018; Bublitz et al., 2019; Neuhoff et al., 2023) due to the inherent uncertainty of financial returns (de Maere d’Aertrycke et al., 2017; Fabra, 2023; Mastropietro et al., 2019).

Economic theory and power system modelling has long demonstrated organized spot markets can clear demand and provide adequate investment signals for requisite new capacity (Schweppe *et al.*, 1988). However, the assumptions and conditions under which this occurs are hard to replicate in practice. These include high spot market price ceilings reflective of the Value of Lost Load (Biggar and Hesamzadeh, 2024), minimal regulatory interference (Joskow, 2008; Hogan, 2013; Spees et al., 2013; Leautier, 2016), a market constantly tracking equilibrium or alternatively, a predominantly equity-funded generation fleet able to withstand extended wholesale market business cycles (Arango and Larsen, 2011; Cepeda and Finon, 2011).

Good economic theory often collides with applied corporate finance. In practice, merchant generators face rigid debt schedules, meaning the canonical energy-only market model inadequately addresses how power plant sunk costs are actually financed (Joskow, 2006; Finon, 2008; Caplan, 2012). Further, energy-only markets are *rarely* in equilibrium (Simshauser, 2020). A competitive power system operating in a secure state with limited scarcity events does not necessarily produce a stable equilibrium in the short

[1] Early entrant batteries can be expected to earn significant revenues from ancillary service markets. However, an influx of batteries will quickly lead to an oversupplied market for spinning reserves. At this point, intraday price spreads and ‘arbitrage revenues’ become the crucial source of net revenues.

run given substantial fixed and sunk costs — an electricity industry problem recognized long ago by Hotelling (1938), Boiteux (1949) and Turvey (1964).

However, in an energy-only market there should be no question requisite plant capacity will *eventually* enter (Simshauser, 2020). Yet as Bidwell and Henney (2004) demonstrate, the power system needs to be operating on the edge of collapse before a fleet of peaking plant can earn sufficient revenues from the spot market. The introduction of a large fleet of renewable generators, with their near zero marginal running costs, is thought to complicate the spot revenue recovery task of peaking generators in energy-only markets due to the near zero marginal cost of solar and wind (Hirth et al., 2016; Joskow, 2019; Graf et al., 2026).

2.3 The missing money

In the literature, the concept of *'the missing money'* usually emerges as the single largest risk associated with achieving resource adequacy in energy-only markets. In simple terms, missing money translates to insufficient total revenues in the energy-only market compared to the expected risk-adjusted revenues of the aggregate plant stock earning a normal return. Missing money is not a consequence of episodic periods of overcapacity. It is a direct consequence of a poorly designed energy-only market, characterised by artificially low spot market price ceilings (Cramton and Stoft, 2005, 2006) or excessive and capricious interference by regulatory authorities to suppress otherwise legitimate spot market price spikes (Hogan, 2005; Meade, 2005; Newbery, 2018). In either case, net spot market revenues of the generation fleet are anticipated to fall short of risk-adjusted returns. And once again, peaking GTs are thought to be particularly vulnerable (Bajo-Buenestado, 2017; Keppler, 2017; Milstein and Tishler, 2019).

2.4 Well-designed energy-only markets

The counterfactual to Sections 2.2-2.3 collapses down to well-designed energy-only markets. The key determinant of a robust market design is whether the (administratively determined) spot market price ceiling exhibits a close relationship with the reliability standard (see Zachary et al., 2019).[2] This is the case in Australia's NEM, which has a very high spot market price ceiling of \$20,300/MWh – multiples of the ~\$100/MWh average spot price.[3]

In an energy-only market, severe price spikes or 'full strength pricing' (Billimoria et al., 2025) are a feature rather than a *problem* of a well-designed energy-only market. And while there is well documented evidence of merit order effects in most energy markets, evidence from the NEM tends to suggest such effects are trivial in the higher quantiles of the spot price distribution (Gonçalves and Menezes, 2022; Mwampashi and Nikitopoulos, 2025) – the distribution relevant to the bankability of GTs.

[2] From a power system planning perspective, the overall objective function is to minimise $VoLL\ x\ USE + \sum_{i=1}^{n} c(G)\ |\ VoLL\ x\ USE + c(\bar{G}) = 0$, where $VoLL$ is the Value of Lost Load, USE is Unserved Energy, and where $c(G)$ is the cost generation plant, and $c(\bar{G})$ is the cost of peaking plant capacity. Provided these conditions hold, it can be said there is a direct relationship between Reliability and the VoLL. An alternate expression where reliability criteria is based on Loss of Load Expectation is $LoLE = e(GT_c)/VoLL$, where $e(GT_c)$ is the expected cost of a new entrant Gas Turbine. For an excellent discussion on the relationship between VoLL and reliability criteria, see Zachary et al. (2019).

[3] Interestingly, Brown and Sappington (2025) find a tipping point where very market price caps (i.e. such as those in Australia's NEM) may begin to adversely impact forward market liquidity through risk averse hedging behaviour of generators.

2.5 Forward markets

Crucially, plant participating in energy-only markets are *not* singularly reliant on the spot market for revenues. Given the absence of administratively determined capacity payments, an essential element of an energy-only market is the accompanying forward market for derivatives (Flottmann et al., 2024; Flottmann et al., 2025). Spot markets guide generator scheduling, dispatch and security of supply (in operational timeframes). The forward market for derivatives guides investment in new generation plant to maintain a reliable power system (in planning timeframes). Specifically in Australia's NEM, baseload 'swap' derivatives identify energy imbalances, and $300 Cap derivatives (i.e. a one-way call option with a $300 strike price) identify capacity imbalances. The latter hence operates as the NEM's 'capacity market equivalent'. When the physical (spot) and financial (forward derivatives) markets are combined, revenues become more robust (Simshauser, 2020; Flottmann et al., 2022; Gohdes, 2025).

The remaining issue then becomes one of incomplete markets — the inability of energy-only markets to provide the optimal mix of forward derivative instruments needed for efficient plant entry, and in particular, long-dated contracts favoured by risk-averse project banks (see Meyer, 2012; Newbery, 2016, 2017; Grubb and Newbery, 2018; Bublitz et al., 2019). In the NEM, vertical integration became a preferred strategy to address the unique complexities of merchant peaking plant investments in the absence of a liquid market for very long-dated contracts. These complexities include high asset specificity, bounded rationality, asymmetric information between generators and retailers, long asset lives, and significant financial hazards associated with capital-intensive investments (Meade, 2005; Hogan and Meade, 2007; Simshauser, 2021).

For now, the task is to assess the bankability of GTs under an array of financing structures and industrial organisation in the presence of complete and incomplete forward markets.

3. Models and Data

Any power plant valuation requires robust forecasts of future electricity prices, fuel prices and expected production levels as a necessary precondition. Baker et al., (1998) and Pindyck (1999) observed that four modelling processes exist for this purpose:

1. spread option models. reliant on observed futures data where plant operate under conditions of perfect availability (see Fleten and Näsäkkälä, 2010);

2. Tree methods, which capture generator non-convexities such a unit start-up costs, minimum run times and ramp-rate constraints (see Tseng and Lin, 2007; Abadie and Chamorro, 2008; Elias, Wahab and Fang, 2017);

3. Stochastic modelling techniques incorporating Monte Carlo simulations, which draw from methods originated in the financial markets designed to capture underlying factors of critical value (see Cassano and Sick, 2013; Abadie, 2015); and

4. Structural LP models (i.e. power system utility planning models) designed to capture the aggregate plant stock and aggregate demand, power plant non-convexities, weather dynamics relating to renewables and loads and an array of other factors, typically run at half-hourly or hourly resolution over multiple years (Marshman et al., 2020a; Marshman et al., 2022)

Electricity utilities and project banks rely heavily on structural models for generation investment and due diligence processes, respectively (see Gohdes et al., 2022, 2023). Structural models, particularly time-sequential models that maintain chronology[4], are well-suited to providing intermediate-run market price dynamics. If industry long-run marginal costs are stable, they also provide long-run dynamic insights. Such models are faithful to the inputs provided, but are extremely data- and processing-intensive with two notable limitations:

- Owing to their data-intensive nature, they typically analyse single weather years, or an average of a small array of weather years.

- The idiosyncratic features of energy-only markets that drive price spikes (e.g. network outages, network congestion, transient variations to ramp rates and fuel costs, erratic bidding behaviour) are exceedingly difficult to model.

Consequently, while structural LP models are ideal for analysing overall market averages (i.e. prices, production and fuel consumed by base and semi-base coal, nuclear, gas, hydro, wind and solar plants), they tend to under-replicate the idiosyncratic features of the markets and may under-estimate high-end volatility (Simshauser, 2020).

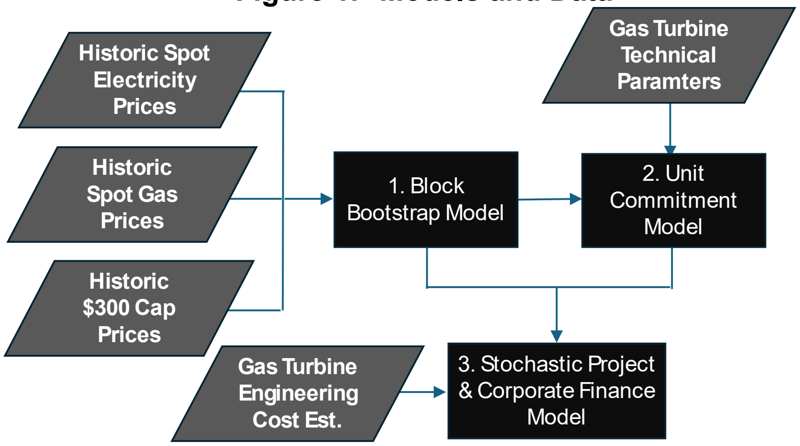
For this reason, the modelling sequence used in this research lies somewhere between the (3) stochastic and (4) structural models. Specifically, to assess the *bankability* of GTs in an energy-only market, three interlinked models are relied on (see Fig.1):

1. A 'block bootstrapping model' which generates 10,000 years of stochastic spot electricity, spot gas and electricity futures price data;
2. A 'unit commitment model' which generates production, spot revenues, derivative contract settlements, and fuel costs; and
3. A stochastic 'project and corporate finance model' which produces a distribution of GT plant valuation estimates for a range of financing structures.

Model and data interaction are illustrated in Fig.1. The balance of this Section explains the model logic and data.

[4] Maintaining chronology has become increasingly important given the relationship between wind, solar and weather conditions. See Merrick et al., (2024).

Figure 1: Models and Data

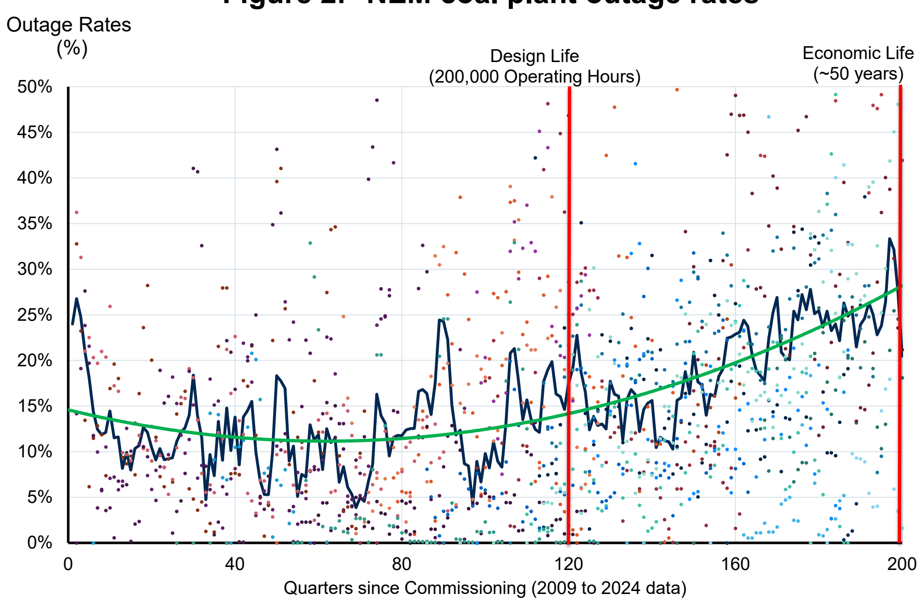


3.1 Block bootstrapping model for spot and forward prices

To stress-test GT valuations in an energy-only market, the observed properties of the distribution of historic spot price volatility needs to be captured and amplified (upwards and downwards). The reason for maintaining volatility in forecasts has two drivers:

1. The remaining coal fleet in any power system will be subject to more (not less) forced outage rates due to age. Fig.1 shows the outage rate (y-axis) of every coal unit in Australia's NEM, measured by their age (x-axis) over the period 2005-2025. The engineering design life is identified by the first vertical red line (30 years), and the economic life used in M&A transactions is identified by the second vertical red line (50 years). Note the average retirement age of Australia's coal fleet is currently 44 years of service.[5] The fleet average outage rate clearly rises from ~80 Quarters (i.e. 20 years). At the time of writing, the NEM's remaining coal fleet had an average age of 38 years.

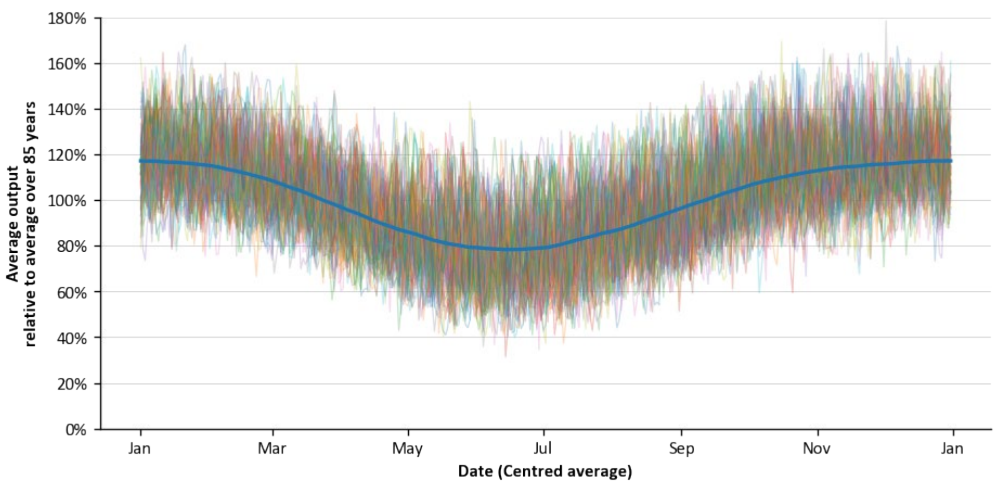
Figure 2: NEM coal plant outage rates



[5] Energy Information Administration data reveals that the average age of the 145GW retired US coal fleet was 49.2 years.

2. Weather (both mild and extreme) will amplify market prices given rising wind and solar generation. Fig.2, drawn from Gilmore et al., (2025), shows the variation in output from a diversified fleet of wind and solar PV plants using 80 years of hourly weather reanalysis data in Australia. Each individual line represents one weather year, with the average result represented by the solid blue line.

Figure 3: 80 weather years of wind and solar production in the NEM



A robust method of approaching this task is 'block bootstrapping' – a non-parametric method of re-sampling 'blocks' of continuous timeseries data (Dudek et al., 2016). Block bootstrapping preserves temporal and chronological dependencies (e.g. morning and evening peaks, summer vs. winter etc), and causal relationships (e.g. solar or wind-intensive periods with low spot prices, high gas prices with high electricity prices etc). For this purpose, 9 years of observed half-hourly spot prices (2017-2025) from the NEM's Queensland region have been used as the base along with chronologically matched daily spot gas prices, and (11 years of) $300 Cap derivative prices from 2014-2024 (noting forward markets trade 3-years prior to delivery). The *block bootstrapping* model logic is as follows:

Let $X = (X_1, X_2, \dots X_T)$, where X denotes the original time series, and each observation corresponds to a half-hourly spot electricity market trading interval, a daily spot gas price, or a traded quarterly Cap contract (daily resolution).

Given block length b, there are evidently $M = T/b$ non-overlapping blocks where:

$$B_i = \left(X_{(i-1)b+1}, X_{(i-1)b+2}, \dots X_{ib}\right) \; for \; i = 1, 2, \dots M. \tag{1}$$

To preserve underlying seasonal effects, blocks are divided into S subsets $\{B_i^{(1)}, B_i^{(2)}, \dots, B_i^{(S)}\}$ each representing a month, quarter, half-year or other specified seasonal period. For each subset, extract $k = \frac{T_s}{b} \; where \; b|T_s$ blocks with replacement, where T_s is the total observations within period s. At this point, the k blocks need to be concatenated in chronological order to form the new 'synthetic' time series.

$$X^* = (X_1^*, X_2^*, \dots, X_N^*), \tag{2}$$

This process is then repeated (R) to generate a set of sample years:

$$\{X^{*(1)}, X^{*(2)}, \dots, X^{*(R)}\} \to R = 10{,}000, \tag{3}$$

There are 17,520 half-hourly spot electricity prices in a year $(N = 17{,}520)$. And while spot gas prices and $300 Caps are traded at daily resolution $(N = 365)$, temporal and chronological dependencies across the three market prices have been preserved in each block B_i.

3.2 Unit commitment model, GT costs and engineering parameters

When operational constraints are set aside, the underpinning logic of Unit Commitment Models is straight forward (Hlouskova *et al.*, 2005). Let p_t^s be the electricity spot price in trading interval t. Within each half-hour trading interval:

$$q_t = \begin{cases} 0, & p_t^s < MC_t \\ q^{max}, & p_t^s \geq MC_t \end{cases} \tag{4}$$

where:

MC_t is the plant's marginal cost of production,
q_t is production output,
q^{max} is the plant's maximum power output.

Gross Profit π_t in each trading interval captures non-negative spark spreads, and as asset-backed traders, unit commitment aims to ensure any forward derivatives sold v_t at contract strike price p_t^c and call option premium p_t^{cp} are physically covered:

$$\pi_t = \begin{cases} \left(v_t \cdot p_t^{cp}\right) + \max\left(0, v_t \cdot (p_t^s - p_t^c\right), & p_t^s < MC_t \\ [q_t \cdot (p_t^s - MC_t)] + \left[\left(v_t \cdot p_t^{cp}\right) + \max\left(0, v_t \cdot (p_t^s - p_t^c\right)\right], & p_t^s \geq MC_t \end{cases} \tag{5}$$

The unit commitment decisions of GTs are subject to various constraints (temperature adjusted maximum rated capacity, planned and forced maintenance outages) and an array of non-convexities (start-up times, starting costs, ramp rates, minimum stable loads, minimum run times). Failing to capture these by using simple spark spread models (e.g. Model #1 described at the start of Section 3) will overvalue GTs. Consequently, more detail in the unit commitment model is required:

Let $Q = \{q_1, q_2, \dots, q_{|N|}\}$ be the ordered set of gas turbine units on site. For each unit q_j let q_j^{max} represent its maximum continuous rating. Let N be the ordered set of half-hour trading intervals such that:

$$t \in \{1..|N|\} \wedge n_t \in N, \tag{6}$$

GT Marginal Costs include fuel $g(q_{j,t})$ and Variable Operations & Maintenance costs (VOM_t). Fuel cost (i.e. natural gas) $g(q_{j,t})$ is non-convex because of start-up quantity a_j with marginal fuel consumed at the plant's heat rate HR_t. Each coefficient is strictly non-negative. Let φ_t be the price of fuel. Once operational, $MC_{j,t}$ reduces because Fuel consumed during the start-up sequence (a_j) is sunk.

$$MC_{j,t} = g(q_{j,t}) + (q_{j,t} \cdot VOM_t) \left| g(q_{j,t}) = \begin{cases} \varphi_t \cdot [a_j + (HR_t \cdot q_{j,t})], & q_{j,t-1} = 0 \\ \varphi_t \cdot (HR_t \cdot q_{j,t}), & q_{j,t-1} > 0 \end{cases} \right. \quad (7)$$

Following unit commitment, power production from each GT unit $q_{j,t}$ is bounded by maximum rated capacity q_j^{max} and its minimum stable load q_j^{min}.

$$q_j^{min} < q_{j,t} < q_j^{max} \;\; \forall \, q_{j,t} > 0, \quad (8)$$

All GTs units undertake scheduled or 'planned' maintenance $\left(o_{j,t}^p\right)$, and are subject to forced outages $\left(o_{j,t}^f\right)$. Forced outages, which include 'failed starts', are manifestly random and occur continuously throughout the year. The maximum available capacity at time t is:

$$\sum_{j=1}^{|Q^{max}|} q_{j,t}^{max} \left| \; q_{j,t}^{max} \le \begin{cases} q_j^{max}, & rand[0..1] < o_{j,t}^f \; and \; t \neq o_{j,t}^p \\ 0, & rand[0..1] \ge o_{j,t}^f \; and \; t = o_{j,t}^p \end{cases} \right. \quad (9)$$

Under sudden price spikes, GTs face a start-up constraint (δ_j). This makes $q_{j,t}^{max}$ production levels in the first trading interval following unit commitment non-feasible:

$$q_{j,t}^{max} \le \begin{cases} \delta_j \cdot q_j^{max}, & q_{j,t-1} = 0 \\ q_j^{max}, & q_{j,t-1} \neq 0 \end{cases} \quad (10)$$

Certain GTs may also face minimum run time constraints. In the model, GT unit commitment is moderated by the expected p_t^s over a (nominally four hour) look-ahead period, (l), to ensure production output responds to extreme spikes or periods of sustained moderate high prices.[6] If a unit is already in service it will remain so where marginal value is anticipated:

$$q_{j,t}^{max} \le \begin{cases} q_j^{max}, & \sum_{t}^{t+l} \frac{p_t^s}{l} \ge MC_t \\ q_j^{max}, & q_{j,t-1} > 0 \;\wedge\; p_t^s \ge MC_t \\ 0, & otherwise \end{cases} \quad (11)$$

3.3 Stochastic Project & Corporate Finance Model

Plant valuations occur within a commercial-grade *Project & Corporate Finance Model* (PCF Model) with annual resolution. The model accommodates both on-balance sheet and structured project financings set within various forms of industrial organisation. The model logic solves for a post-tax, post-financing equity IRR constraint with debt sizing

[6] The consequence of Eq.(13) is that the station will sometimes start early in anticipation of a major price spike thereby capturing realistic behaviour under uncertainty, and may not generate during brief spikes of low profitability thereby avoiding unnecessary operating hours and/or unit starts. However, subject to Eq.(11) unit commitment will always hit major price spikes reflecting an assumption of high quality short-term price forecasting.

simultaneously constrained by observed banking covenants and credit metrics, with taxation variables co-optimised endogenously.

The PCF model also incorporates a stochastic Monte Carlo engine with a sub-sampling process that populates each future operational year ($Y = 1..35$) from the 10,000-year array of block bootstrapped data (drawn from the Unit Commitment Model). This generates an inherently volatile series of future spot prices reflecting the environment facing a GT in an energy-only market. This Monte Carlo engine is then iterated ($i = 1000$), thus producing 1000 unique plant valuations as in Hlouskova et al., (2005) and Simshauser (2020). The full PCF Model logic appears in Appendix II (with Eq.A14 being the critical debt-sizing constraint). A summary-level exposition of the i^{th} valuation of gas turbine Q is calculated as follows:

$$PV_Q^i = PV_Q^i \left[\!\left[\sum_{Y=1}^{35} \sum_{j=1}^{Q} \left\langle \sum_{t=1}^{N} \left[\left\{ q_{j,t} \cdot (p_t^s - MC_t) \right\} + \left\{ \left(v_t \cdot p_t^{cp} \right) + \max\left(0, v_t \cdot (p_t^s - p_t^c) \right\} \right] \right\rangle FC_{Q,t} - D_{Q,t} - \tau_{Q,t} \right]\!\right] \quad (12)$$

where

PV_Q^i	= Present Value of OCGT $\left(i^{th}\ iteration\right)$
$FC_{Q,t}$	= Fixed Costs (i.e. Fixed Operations & Maintenance, Insurances etc)
$D_{Q,t}$	= Financing costs – see Appendix I and especially Eq.(A11-A15)
$\tau_{Q,t}$	= Cash taxes payable

With 1000 iterations, the final GT valuation is therefore:

$$PV_Q = median\left(\left\{PV_Q^1, PV_Q^2, \dots PV_Q^{1000}\right\}\right), \quad (13)$$

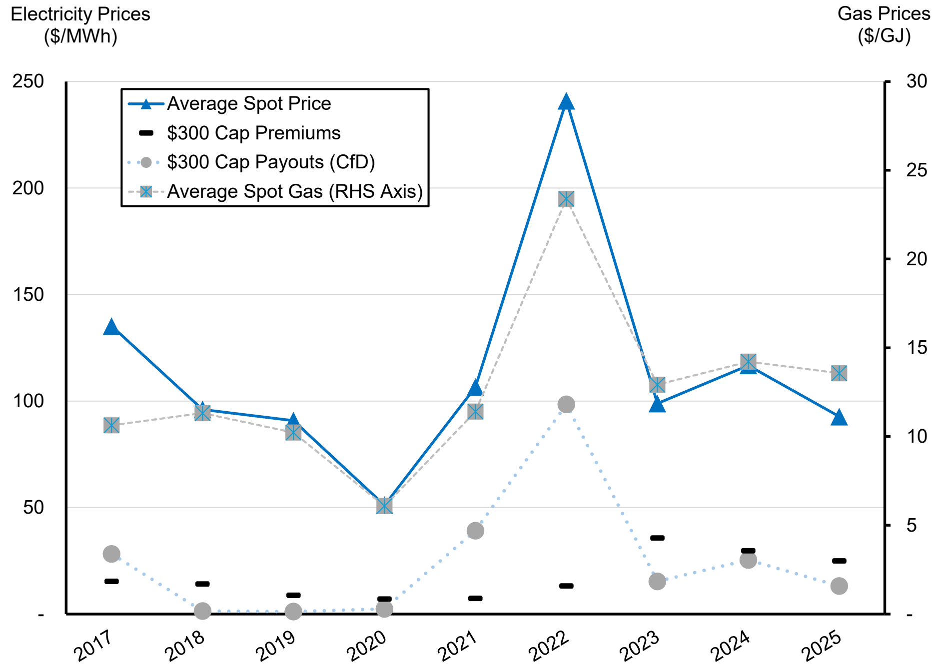
3.4 Price data

Average annual market prices (2017-2025) are illustrated in Fig.4. Spot and forward electricity prices are measured on the LHS y-axis, with spot gas on the RHS axis. Three electricity price series are illustrated:

1. spot prices (dark blue lines, triangular markers)
2. \$300 Cap derivative 'Premiums' (black dashes)
3. Ex post payouts on \$300 Cap derivatives (light blue dotted lines, circular markers).

The Russia-Ukraine war effects in 2022 are visible. Note that \$300 Cap payouts (ex post) exceeded the (ex ante) Cap Premiums paid.

Figure 4: Annual electricity and gas market prices



A more granular analysis of this data is examined in Sections 3.5-3.7.

3.5 Spot electricity price data

30-minute spot price data from the NEM's Queensland region forms the block bootstrapping base. The dataset comprises ~155,000 observations and spans an energy market business cycle, including periods of over-weight and under-weight baseload capacity, merit order effects and rebounds (i.e. low prices with 'renewables on', high spot prices with 'renewables off'). A statistical summary is presented in Tab1. Of note are the elevated Skewness and Kurtosis statistics.

Table 1: Spot electricity prices (2017-2025)

	Qld Region	2025$	2017	2018	2019	2020	2021	2022	2023	2024	2025	2017-2025
1	Observations	#	17,520	17,520	17,520	17,567	17,520	17,520	17,520	17,568	14,593	154,847
2	Average Spot**	$/MWh	134.2	96.2	90.8	51.3	105.6	236.0	98.4	116.7	93.6	100.8
3	Max Spot	$/MWh	18,333.3	3,197.8	5,487.8	3,055.9	18,578.0	17,923.9	12,112.3	16,231.4	14,862.6	18,578.0
4	Min Spot	$/MWh	-526.7	-393.6	-1,000.0	-878.0	-1,000.0	-109.5	-115.1	-211.1	-381.3	-1,000.0
5	-ve Prices	Hrs pa	6.5	8.0	124.5	324.5	511.0	388.5	1,159.5	1,226.5	1,328.5	5,077.5
6	Std Deviation		432.7	61.8	67.1	459.6	419.1	586.7	247.0	409.3	323.7	351.8
7	Skewness		26.8	27.4	29.1	22.7	24.7	19.1	24.3	25.6	32.3	29.7
8	Kurtosis		874.9	1,204.5	2,425.2	713.2	765.0	449.0	784.2	789.7	1,194.2	1,137.9
9	PoE10 Spot	$/MWh	153.1	135.1	135.0	147.3	270.0	405.8	182.6	220.7	165.3	188.5
10	PoE90 Spot	$/MWh	73.5	65.5	51.2	20.8	-12.5	41.7	-19.5	-22.9	-17.5	24.0
11	Volatility*	(Line 6 / 2)	3.2	0.6	0.7	9.0	4.0	2.5	2.5	3.5	3.5	~~3.1~~
	* Coefficient of Variation		** Overall average spot price (2017-2022) of $100.8 reflects 10,000 iterations with 6500 iterations excluding the 2022 year									

Source: Australian Energy Market Operator, Australian Bureau of Statistics.

3.6 Spot gas price data

The spot gas price dataset (daily resolution) comprises ~3200 observations and is illustrated in Tab.2.

Table 2: Spot gas prices (2017-2025)

	Qld Region	2025$	2017	2018	2019	2020	2021	2022	2023	2024	2025	2017-2025
1	Observations	#	365	365	365	366	365	365	365	366	334	3,256
2	Average Spot	$/GJ	10.7	11.4	10.2	6.1	11.3	24.6	13.1	14.0	13.5	12.8
3	Max Spot	$/GJ	20.5	18.3	14.7	12.5	24.9	59.5	26.7	25.4	21.3	59.5
4	Min Spot	$/GJ	7.1	7.4	4.7	3.8	6.1	8.5	6.2	9.9	8.5	3.8
5	Std Deviation		2.4	1.8	1.7	1.7	3.7	12.8	3.2	2.1	1.6	6.8
6	Skewness		1.8	-0.0	-0.2	0.8	1.2	0.9	1.1	1.7	0.2	3.2
7	Kurtosis		3.3	-0.2	-0.2	0.7	1.1	-0.4	2.2	4.3	3.1	13.9
8	PoE10 Spot	$/GJ	13.5	13.5	12.3	8.4	16.7	46.1	17.0	16.5	15.1	17.8
9	PoE90 Spot	$/GJ	8.4	9.0	8.0	4.2	7.8	11.6	9.7	12.1	11.5	7.5
10	Volatility*	(Line 6 / 2)	0.23	0.16	0.17	0.27	0.33	0.52	0.25	0.15	0.12	0.53
	* Coefficient of Variation											

Source: Australian Energy Market Operator, Australian Bureau of Statistics

Nolan et al., (2022) note quarterly average spot electricity and gas price data are *very* highly correlated, with the data used here revealing ($r = 0.97$). At higher resolution there is however marked variation. Half-hourly spot electricity prices are left-skewed with a leptokurtic distribution (see Skewness, Tab.1, Line 7) due to the high spot market price ceiling of $20,300/MWh. Year-on-year, the volatility of spot electricity prices is 15x spot gas prices.

Conversely, the distribution of natural gas prices exhibits a platykurtic distribution (i.e. relatively flat-topped distribution with thin tails) as indicated by the comparatively low, and at times negative, Kurtosis statistics (see Tab.2 Line 7).

3.7 Forward prices: $300 Cap derivatives

The forward market instrument relevant to GTs are $300 Caps – a continuous call option or one-way CfD with a $300/MWh strike price. The theoretical equilibrium price of $300 Cap derivatives is calibrated to the annual carrying cost (i.e. fixed and sunk costs) of the *benchmark* peaking technology. Once a $300 Cap has been sold, the obligation is 'firm' to the spot market price ceiling of $20,300/MWh. Being a cash-settled derivative, the contract is active under all circumstances regardless of whether the plant is available or not. A 2 or 4hr battery is therefore not a suitable proxy for such duties. Over the period 2017-2025, there have been 105 days where spot prices exceeding $300 for more than 6hrs in a row, and 92 days for more than 8hrs.

Tab.3 shows the traded price of $300 Caps by Quarters (min, max, average standard deviation – see Lines 3-7), and annual Strips – a strip comprising the four quarters of the calendar year (Lines 8-12). Given the averaging nature of hedge contracts, their volatility (Line 12) is an order of magnitude lower than the spot market.[7]

Note Tab.3 (Line 12) there is a '3-year Portfolio' price. This price is constructed by progressively *layering-in* $300 Caps into a portfolio over a 3-year run-of-trade accumulation prior to delivery in year N at a ratio of 5% in $N-3$, 25% in $N-2$, and 75% in $N-1$. This has been the (ex post) optimal timing of $300 Cap commitments. Ex post optimality for each individual year varies considerably, but for the purposes of this research, it provides a risk-neutral portfolio structure. From a block bootstrapping perspective, the portfolio is constructed at Quarterly resolution.

[7] The annualised *fixed and sunk costs* of a GT in many markets are typically expressed in terms of $/MW/a. NEM convention, however, is for Cap Premiums is to be expressed in $/MWh in a continuous payment stream for each hour of the year (i.e. $/MW/a divided by 8760 hrs).

Table 3: $300 Cap prices (2014-2024)

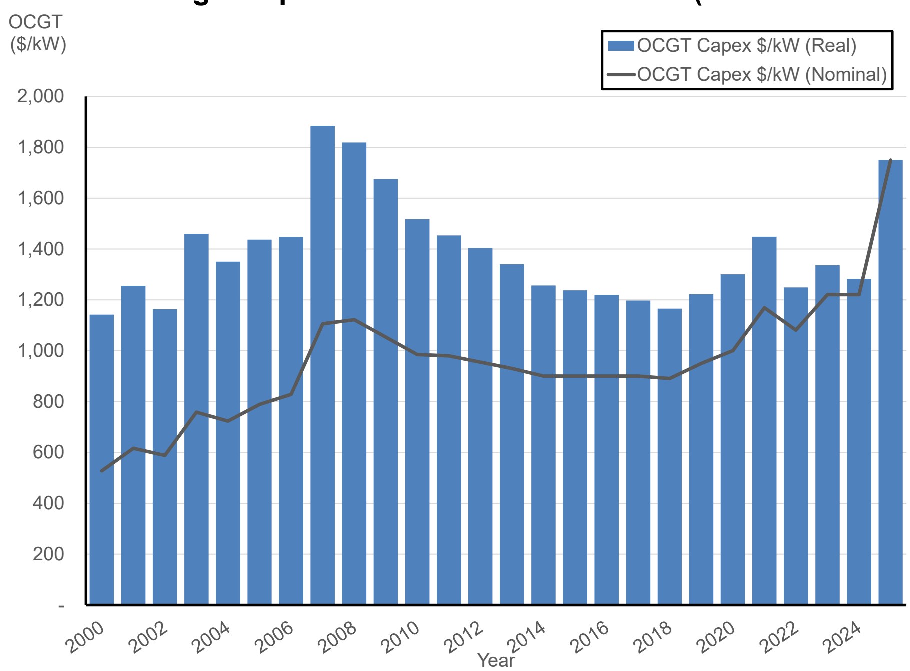
	Qld Region		2017	2018	2019	2020	2021	2022	2023	2024	2017-2024
1	Futures Contracts		2014 - 2016	2015 - 2017	2016 - 2018	2017 - 2019	2018 - 2020	2019 - 2021	2020 - 2022	2021 - 2023	2014-2023
2	Observations	#	764	954	954	827	827	954	956	956	7,192
3	Quarter (Min)	$/MWh	3.3	3.7	2.1	1.8	1.4	3.0	3.2	3.5	1.4
4	Quarter (Max)	$/MWh	38.4	41.3	32.6	22.9	18.0	47.8	107.1	75.8	107.1
5	Quarter (Avg)	$/MWh	11.6	11.9	10.4	8.5	8.9	11.9	27.5	23.8	14.3
6	Quarter (SD)		8.4	8.2	6.4	5.0	4.4	8.8	23.6	16.6	12.5
7	Quarter (Volatility)	SD/Avg	0.7	0.7	0.6	0.6	0.5	0.7	0.9	0.7	0.9
8	Year Strip (Min)	$/MWh	8.3	7.8	5.2	4.2	3.8	6.2	5.8	5.8	3.8
9	Year Strip (Max)	$/MWh	16.9	19.4	15.7	13.6	12.9	20.1	68.7	53.0	68.7
10	Year Strip (Avg)	$/MWh	11.6	11.7	10.4	8.6	9.0	11.9	27.5	23.8	14.5
11	Year Strip (SD)		2.7	2.8	2.9	2.3	2.3	3.4	20.8	12.2	10.2
12	Year Strip (Volatility)	SD/Avg	0.2	0.2	0.3	0.3	0.3	0.3	0.8	0.5	0.7
13	3-Yr Portfolio	$/MWh	13.4	12.5	7.9	6.4	6.7	11.9	33.8	29.0	15.2

Source: ASX Futures.

3.8 GT costs, debt sizing parameters and the costs of capital

Engineering cost estimates, technical parameters and relevant capital markets data are essential inputs to generator valuation models. The GT to be modelled is **100MW in size**, with gas line-pack designed to ensure a minimum of 8hrs run-time per day. At 100MW and an overnight capital cost of $1850/kW, total investment equals $185m. Fig.5 illustrates the evolution of NEM GT capital costs over the past 25 years. Note the sharp step-up in 2025 costs, which have been captured in the present analysis. Plant technical parameters are summarised in Tab.4.

Figure 5: Overnight capital costs of GTs in the NEM (constant 2025 dollars)



Sources: AEMO, Simshauser et al (2009), Australian Bureau of Statistics

Table 4: GT plant parameters

		OCGT
Project Capacity	(MW)	100
- LinePack	(Hrs)	8
Overnight Capital Cost	($/kW)	1,750
- Linepack	($/kW)	100
Plant Capital Cost	($/kW)	1,850
Overnight Capital Cost	($ '000)	185,000
Operating Life	(Yrs)	35
Annual Capacity Factor	(%)	2-20%
Transmission Loss Factor	(MLF)	0.990
Heat Rate	(kJ/kWh)	10,000
Fixed O&M	($/MW/a)	20,000
Variable O&M	($/MWh)	9.7

Capital markets data (Tab.5) includes interest rate swaps, credit spreads, covenants applied by risk averse banks, and the expected (post-tax) equity IRRs for the range of industrial organisation modelled (project financing on the left panel, and corporate finance on the right panel). These represent observed capital markets data along with well-documented debt sizing parameters (see for example Simshauser and Nelson, 2012; Nelson and Simshauser, 2013, Gohdes et al., 2022; Gohdes, 2023). Note also in Tab.5 (Line 27) the GT-specific *'debt spread'*. This is an additional charge of 50 basis points (bps) applied to GT debt facilities to reflect a fossil fuel risk premia.[8]

Table 5: Capital markets

	Project Finance		PPA	Merchant
	Debt Sizing Constraints			
1	- DSCR	(times)	1.25	1.85
2	- Gearing Limit	(%)	80%	40%
3	- Default	(times)	1.05	1.05
4	PF Facilities - Tenor			
5	- Term Loan B (Bullet)	(Yrs)	5	5
6	- Term Loan A (Amortising)	(Yrs)	7	7
7	- Notional amortisation	(Yrs)	25	25
8	PF Facilities - Pricing			
9	- Term Loan B Swap	(%)	3.81%	3.81%
10	- Term Loan B PF Spread	(bps)	180	240
11	- Term Loan A Swap	(%)	3.99%	3.99%
12	- Term Loan A PF Spread	(bps)	209	289
13	- Refinancing Rate	(%)	6.5%	7.1%
14	Expected Equity Returns	(%)	10.0%	12.0%

	Balance Sheet Finacings		Vertical Integ.
	Credit Metrics (BBB Corporate)		
17	- FFO / I	(times)	4.2
18	- Gearing Limit	(%)	40.0
19	- FFO / Debt	(%)	20%
20	Bond Issues		
21	- 5 Year	(%)	4.99%
22	- 7 Year	(%)	5.29%
23	- 10 Year	(%)	5.60%
24	Commonwealth Bonds		
25	- 10 Year	(%)	4.27%
26	Expected Equity Returns	(%)	11.0%
	Fossil Fuel Premium		
27	Gas Turbine Debt Spread	(bps)	50

Sources: Bloomberg, Simshauser (2020).

4. Model Results

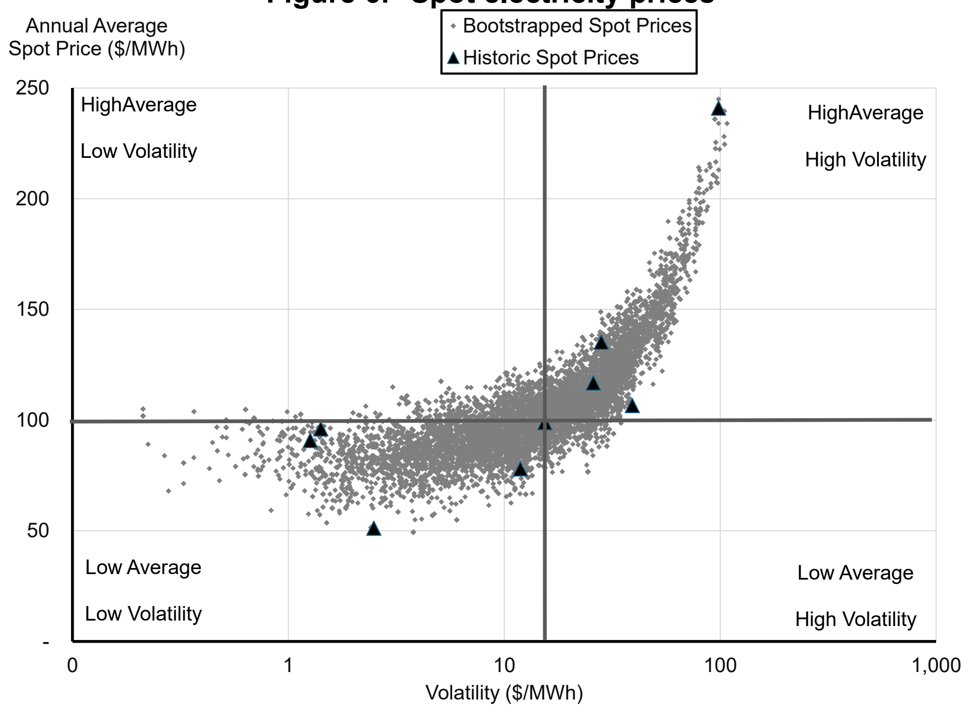
Recall the modelling sequence from Fig.1 started with the (1) Block Bootstrap Model deriving the first set of results – 10,000 years of market prices. These prices are then fed into the (2) Unit Commitment Model, which simulates GT production, spot revenues, forward derivative settlements, gas fuel costs, gross profit and critically – quantifies the optimal risk-adjusted forward hedge portfolio for the 100MW GT. Results from (2) are then transposed into the (3) Stochastic PCF Model, which sizes debt facilities, calculates unit costs, and produces GT plant valuations by sub-sampling the 10,000 years of market data.

[8] The spread of 50bps cannot be observed in the market per se. However, a survey of project bankers contained in Simshauser and Nelson (2012) revealed a 50bps spread between renewables and gas-fired generation under policy uncertainty (as existed in Australia at the time, and again during the mid-2020s).

4.1 Block bootstrap model results

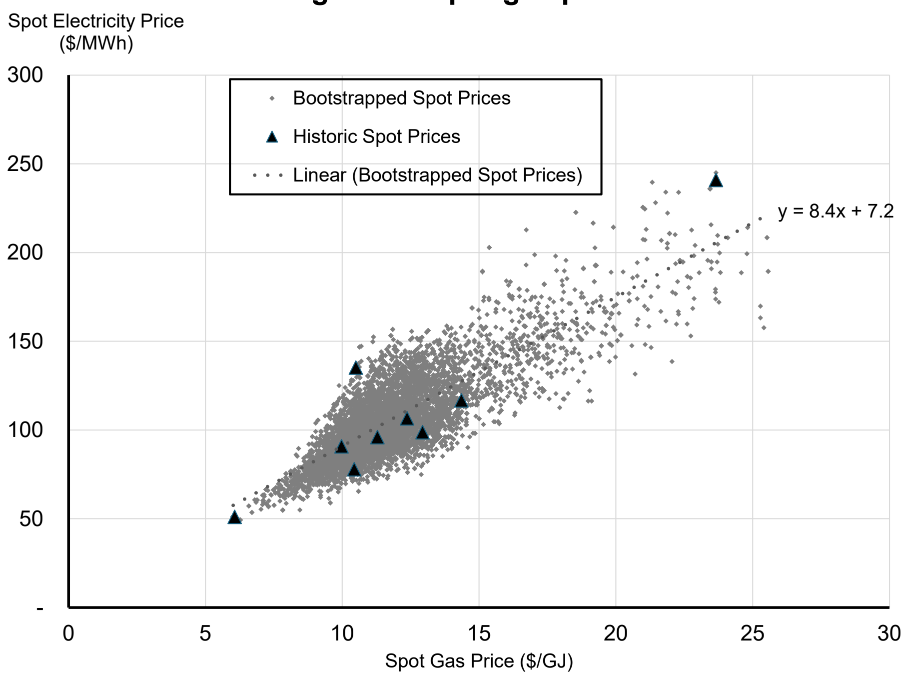
Fig.6 presents the block bootstrap model results for spot electricity prices. The historic spot prices are represented by the black triangle markers, with the synthetic years represented by the grey dots.

Figure 6: Spot electricity prices



In Fig.7 illustrates the block bootstrap results for spot gas. The line of best fit provides an estimate of the Australian market heat rate, viz. $7.2/MWh + 8.4x the spot gas price ($/GJ).

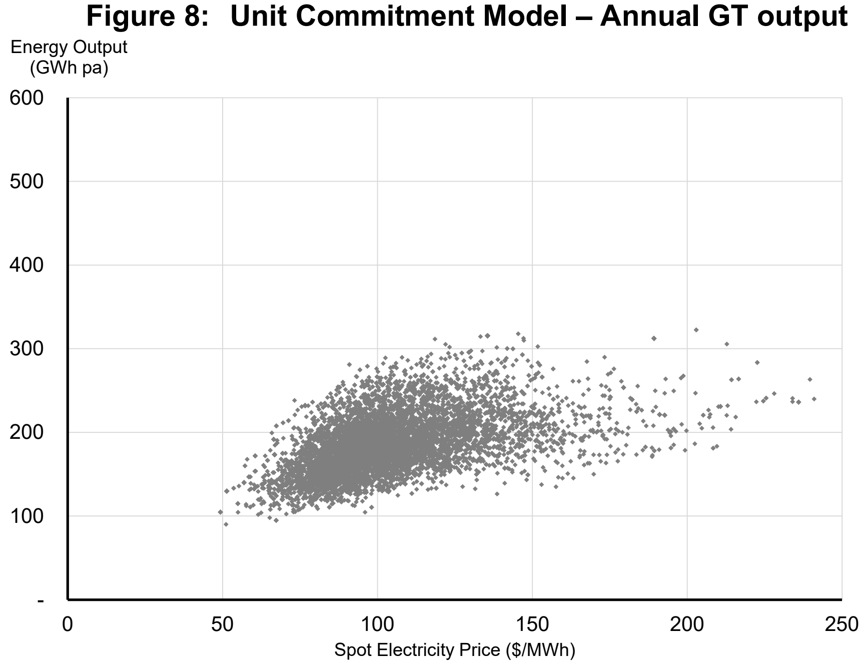
Figure 7: Spot gas prices



4.2 Unit commitment model results

When these data are transposed into the Unit Commitment Model, GT operating duties are revealed and span 180GWh +/- 50GWh pa (Fig.8). Production duties are measured on the y-axis, with average spot prices measured on the x-axis.

Figure 8: Unit Commitment Model – Annual GT output



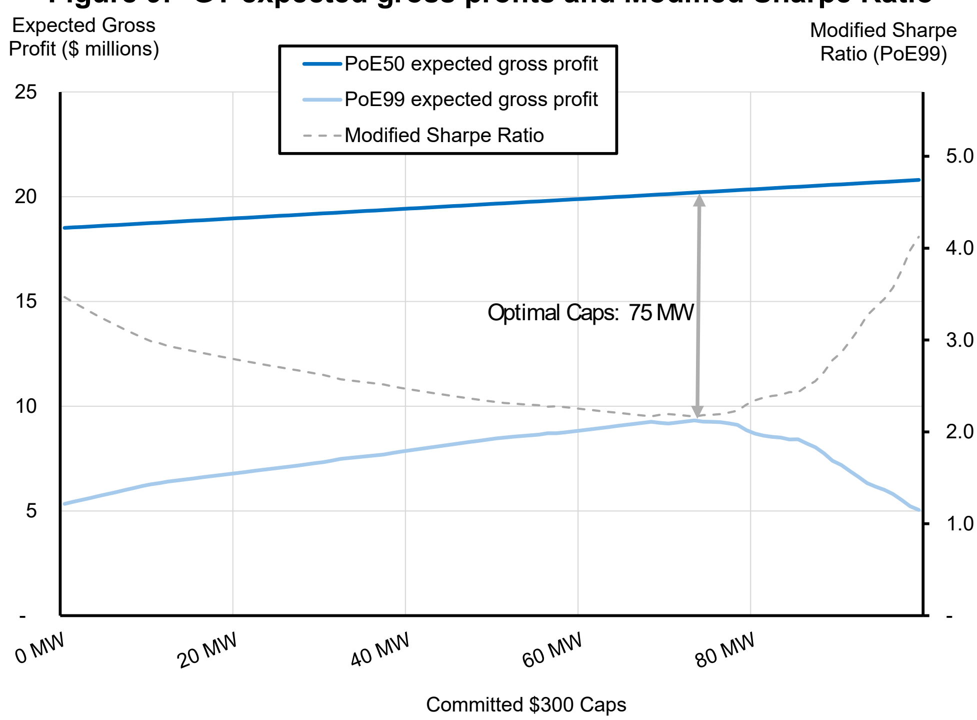
The Unit Commitment Model culminates in expected gross profits (i.e. spot revenues +/- $300 Cap settlements, less gas fuel costs). But such calculations first require the *optimal risk-adjusted forward hedge portfolio* to be defined. As noted above, this is undertaken endogenously within the Unit Commitment Model.

4.3 Optimal Forward Hedge Portfolio

To identify ex ante the optimal hedge portfolio, a sound measure of risk-adjusted returns is required. The seminal works relevant to the task can be traced back to Markowitz's (1952) two-parameter model of portfolio risk and returns, viz. expected or *mean* portfolio returns (numerator), and standard deviation of portfolio returns (denominator) from a portfolio of financial assets (i.e. Sharpe Ratio). This ratio can be readily translated from the financial markets to the commodity markets by substituting expected financial returns for expected gross profits and substituting the standard deviation of returns for the *downside deviation* of expected profits (i.e. *Modified Sharpe Ratio*).

Given 10,000 years of spot and forward price data, expected gross profits equate to the *Probability of Exceedance of 50%* (i.e. PoE50) result. The major modification to the classic Sharpe Ratio is the denominator. Rather than using standard deviation, the *downside deviation* or PoE99 gross profit result is to be used. The reason for this is the asymmetric risk of spot prices (i.e. skewness, Tab.1) and the focus of project banks (i.e. downside scenario) for debt sizing. The Unit Commitment Model produces these calculations for all levels of hedging (0-100%) as illustrated in Fig.9. Fig.9 is a key insight arising from this research.

Figure 9: GT expected gross profits and Modified Sharpe Ratio



The x-axis of Fig.9 measures hedge portfolio levels (0-100MW) of the 100MW GT. The y-axis measures PoE50 and PoE99 expected gross profit (LHS Axis) and *Modified Sharpe Ratio* (RHS axis). These results incorporate the 10,000 years of chronologically matched spot electricity, spot gas and forward $300 Cap price data. Dividing PoE50 by PoE99 results produces the *Modified Sharpe Ratio* as measured by the dashed grey line. A clear picture emerges from these results; PoE50 expected gross profits rise gently as forward hedge levels approach 100MW or 100% of plant capacity. The intuition behind this result is that $300 Caps are fundamentally an insurance product and that on average, Caps are sold at an (ex ante) premium to expected payouts.[9] Periodically however, ex post Cap payouts surge beyond upfront premiums due to unforeseen events. GTs can be simultaneously exposed to forced outages, imperfect start-up times, failed starts and forecast error. For these reasons, 100% hedging with financial derivatives introduces the risk of being 'short' vis-à-vis the spot market during critical events. This risk is not obvious when assessing PoE50 results. But PoE99 results (Fig.9) clearly reveals the tail-end risk. At ~75MW or ~75% hedge cover, the PoE99 result begins to deteriorate and by 85MW, falls sharply. 75MW will therefore be used as the ex-ante *optimal risk-adjusted hedge portfolio*.

To see the impact of the optimal hedge portfolio on the distribution GT gross profits, Fig.10 provides a box plot across the 10,000 years of market data with 0 MW hedged (LHS box) and 75MW hedged (RHS box). From this, four clear outcomes emerge:

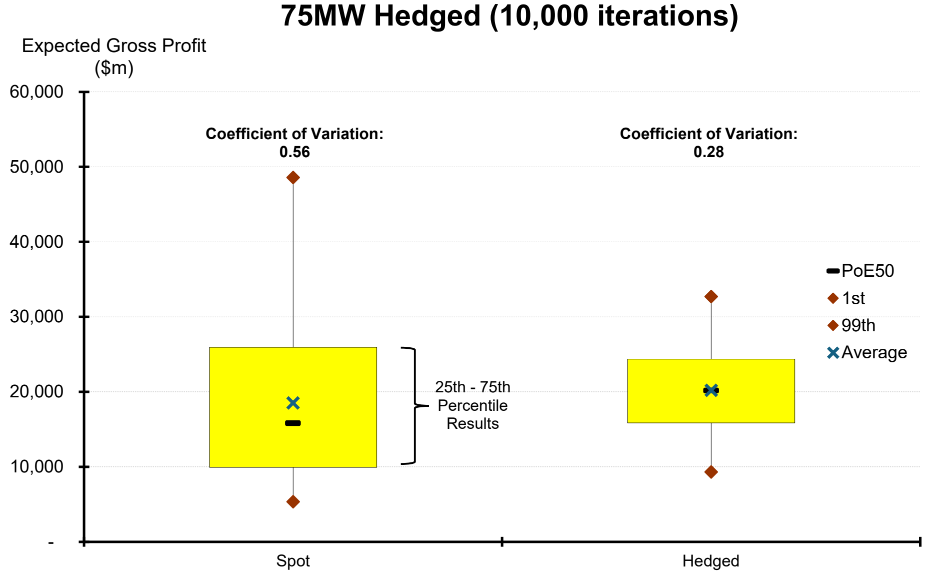
1. Expected (PoE50) gross profits are 27% higher;

2. PoE50 and mean gross profits converge;

3. The volatility of earnings reduces sharply, from 0.56 to 0.28; and

4. PoE99 expected gross profit result is ~75% higher.

Figure 10: Distribution of 100MW GT Gross Profits – Spot exposed vs 75MW Hedged (10,000 iterations)



Figs.9-10 are important results. They ostensibly collide with much of the academic literature on peaking plant in energy-only markets (Section 2). Specifically, while true that GTs are *risky investments* when reliant on spot markets for revenue, the valuation and bankability of a GT should not be undertaken with spot revenues only. To genuinely assess the level of investment risk, both spot *and forward market revenues* need to be assessed. The reason for is this is evident in Fig.10 – forward markets (i.e. hedges) provide *buffering revenues* when the spot market does not. The fact that PoE99

[9] Historically, in ~9 out of 10 years, sellers of $300 Caps make ex post profits in the NEM (see Simshauser, 2020).

expected gross profits are 74% higher provides the practical evidence. Such results will prove critical in debt sizing, as Section 5 reveals.

5. Stochastic PCF Model Results: are GTs bankable?

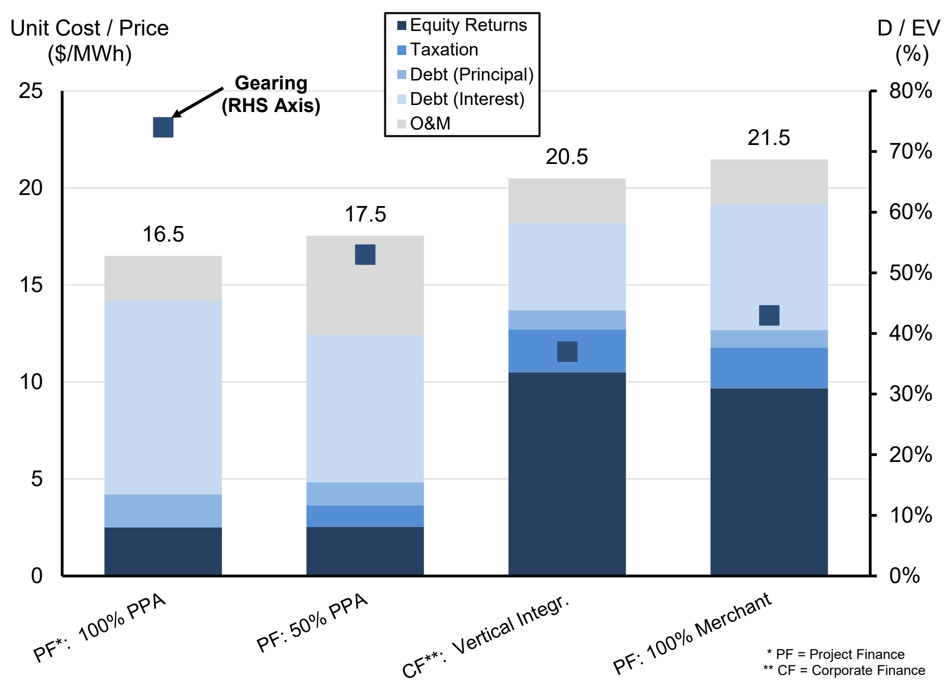
The Stochastic PCF Model produces commercial-grade GT unit entry cost estimates or plant valuations, for a given set of costs or market prices, respectively. This discounted cash flow model incorporates algorithms that size and co-optimise structured debt facilities (or corporate bonds) to minimise post-tax, post-financing entry costs whilst meeting all banking covenant constraints. Moreover, the model has a stochastic engine that sub-samples chronologically consistent spot and forward market revenues and gas fuel costs from the Unit Commitment Model's 10,000 years of market results[10], which in turn, enables a robust distribution of plant valuations to be identified.

5.1 Static unit costs by industrial organisation

Before undertaking market-based valuations, it is useful to identify GT entry costs. Here, market prices are set to one side with the focus being on the annual fixed and sunk costs of GTs. This serves as the market proxy for $300 Cap prices in equilibrium.

GT entry costs vary according to industrial organisation. In Fig.11, four specific forms of industrial organisation are presented and consistent with the literature (see Simshauser and Gilmore, 2020; Gohdes et al., 2022), the lowest carrying cost structure comprises a project financing with the GT underwritten by a run-of-plant PPA covering 100% installed capacity:

Figure 11: Unit cost of GTs by industrial organisation



[10] Specifically, recall from Section 3 the PCF Model randomly samples the spot and forward prices, production and fuel costs from the 10,000 years of available data to populate the 35-year useful life of the GT. This process is then repeated for each i^{th} valuation of GT $\boldsymbol{Q}$, where $\boldsymbol{i} = \mathbf{1,000}$ iterations, with each individual simulation optimising the capital structure according to relevant bank covenants.

1. The first bar in Fig.11 captures the project financed GT with 100% PPA coverage. The PCF Model reveals a unit cost of $16.5/MWh. This result is characterised by the maximal use of debt finance (~74%) as measured by the black square marker (RHS axis). The binding constraint is the debt sizing covenant in Tab.5 (see Line 1), the Debt Service Coverage Ratio of 1.25x.[11]

2. The second bar is the *semi-merchant* plant with 50% PPA coverage at $17.6/MWh. This plant has been modelled with a 50MW run-of-plant PPA, and 25MW of $300 Cap derivatives (75MW in total, being consistent with results in Section 4). However, because only ~50% of the plant's revenues are ex ante *contracted*, banking covenants adjust proportionately (i.e. DSCR threshold rises from 1.25x to 1.55x). Consequently, gearing falls from 74% to ~55%. Being semi-merchant, the equity IRR hurdle also rises to the mid-point of Tab.5, Line 14.

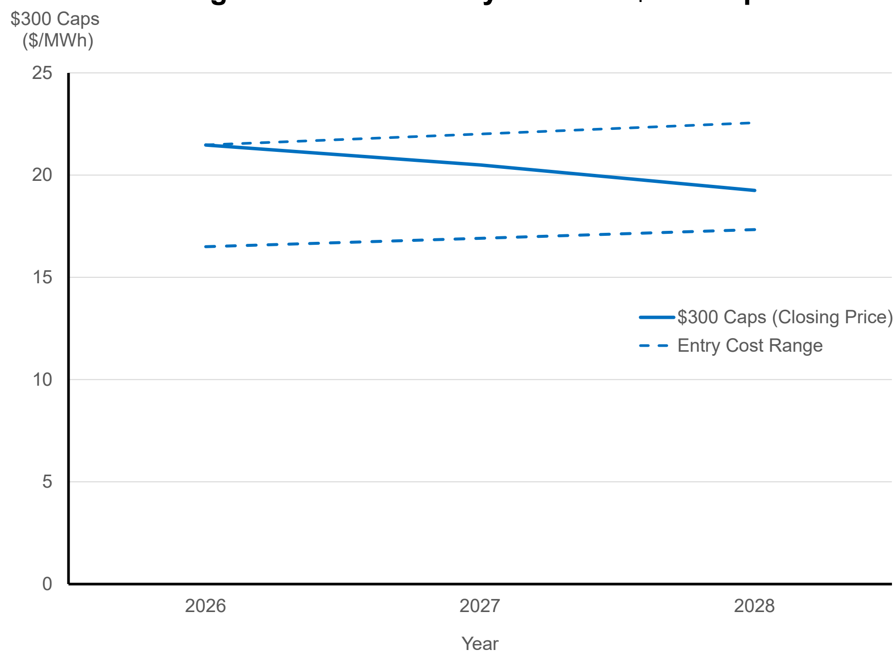
3. The third bar is the vertically integrated merchant utility, at $20.5/MWh. This involves a corporate financing or bond issue with BBB credit metrics, with commensurately lower gearing (~37%). The integrated utility is assumed to internalise the GT for its own hedging purposes. While a PF may appear lower cost, transaction costs, internal synergies and bounded rationality mean this is likely to be optimal for 'Gen-tailers'.

4. The 4th bar is the merchant GT, at $21.5/MWh. This asset is assumed to hold a portfolio of $300 Caps. But with market liquidity limited to 3-years, the level of 'firm contracted revenues' ex ante is just 7% of lifetime GT revenues. As a result, gearing levels fall to 34% (constrained by the DSCR at 1.85x), along with a post-tax equity IRR threshold of 12% (Tab.5, Line 14).

How these results compare to the forward curve for $300 Caps at the time of writing is illustrated in Fig.12. Results suggest $300 Caps are sending an entry signal:

[11] The Debt Service Cover Ratio or 'DSCR' is a calculation comprising 'Cash Available for Debt Service" (numerator) and 'Debt Repayments' (i.e. interest and principal) as denominator. Where plant is fully contracted (i.e. secure revenues) debt sizing is typically undertaken at 1.25x. A merchant plant would be sized at 1.80-1.85x. A semi-merchant with ~50% of contracted revenues would therefore be sized at (0.5 x 1.25x + 0.5 x 1.85x) = ~1.55x.

Figure 12: Entry costs vs $300 Caps



Note Fig.12 *does not include* an assessment of 'under-cap' revenues. The marginal running cost of the GT will, under most circumstances, be well below $300/MWh. Therefore, GTs will earn additional spot market revenues below the $300 Cap strike price. Furthermore, the 100MW GT will retain an exposure to spot prices whenever plant availability is >75MW. To assess these values, we must turn to the Stochastic PCF Model.

5.2 Stochastic plant valuation: semi-merchant GT

In Section 5.1, four different industrial forms of the 100MW GT were examined. Of these, there is no requirement to undertake a stochastic valuation of plant with 100% PPA coverage. Ceteris paribus, provided the PPA price is set ≥$16.5/MWh (i.e. entry cost), the underlying valuation of the 100MW GT of $185 million will be supported.

The same is true of the Balance Sheet financed GT. Provided an internal transfer price exists between a Gen-tailers generation division (internal seller) and a Gen-tailers retailing division (internal buyer), the GT valuation will be supported.

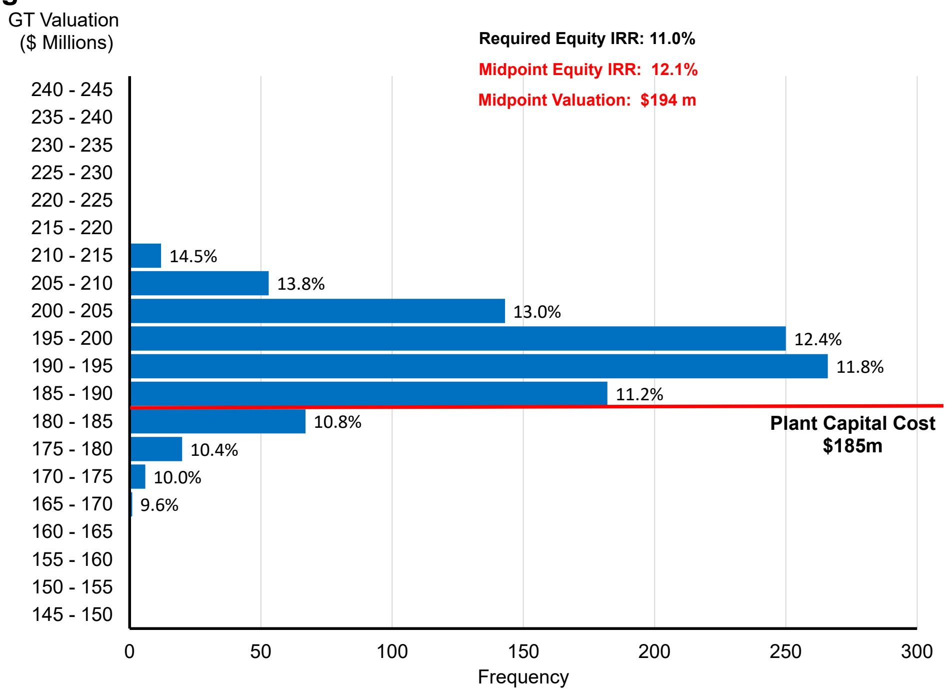
This leaves semi-merchant and merchant GTs. Recall the semi-merchant plant comprises a 50MW PPA (at $16.5/MWh, the efficient PPA price), ~25MW of sold Caps at market prices, and an equity IRR hurdle of 11%. The valuation result (1000 iterations) appears in Fig.13.

In Fig.13, the y-axis lists the valuation range (in $5m 'buckets') and the x-axis captures the frequency of valuations within each 'bucket'.[12] The red horizontal line identifies the plant's capital cost. Results show a wide spread of plausible valuations, from $165m to $215m with the commensurate equity IRRs spanning the range 9.6-14.5%. Project finance gearing levels across scenarios average 55%, with 95th and 5th percentile results

[12] The sum of the blue bars adds up to 1000 individual plant valuations.

of 46% and 64%, respectively. The median valuation result $194m and a post-tax equity IRR of 12.1%. This suggests a semi-merchant GT investment is feasible and tractable.

Figure 13: Stochastic model results – valuation of semi-merchant GT

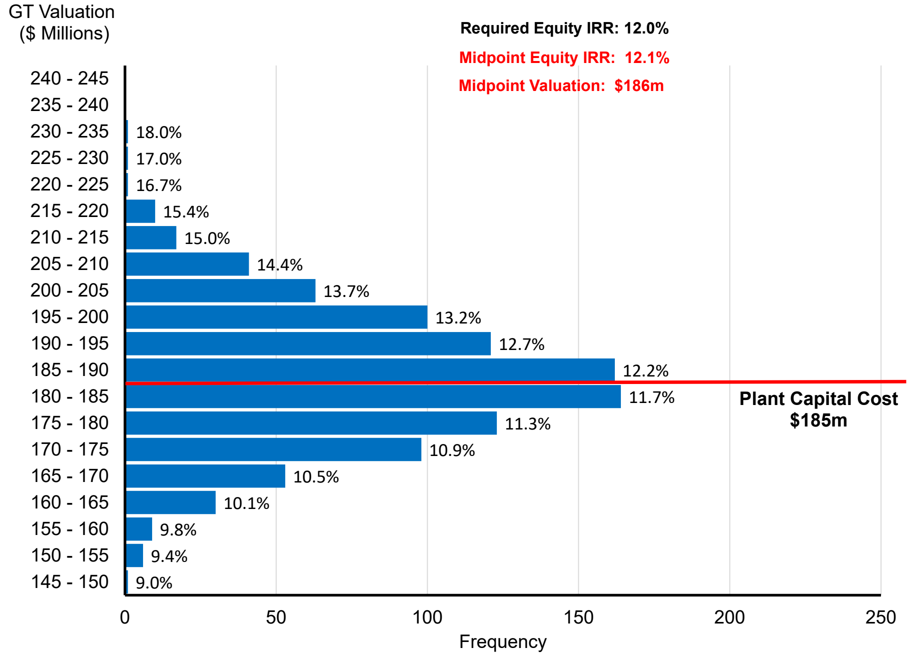


5.3 Stochastic plant valuation: merchant GT

Results in Fig.13 were underwritten by a PPA for 50% of plant capacity. What if there are no credible PPA buyers? A merchant GT has very limited (ex ante) contracted revenues (i.e. <10%). As a result, the equity IRR hurdle is raised to 12% (Tab.5 Line 14) and debt covenants applied by risk averse project banks are tightened further (Tab.5 Lines 1-3). With tighter debt covenants (i.e. less gearing) and a higher equity IRR, the plant will have an inherently higher cost structure (Fig.11). Conversely however, a merchant GT is not constrained by fixed $16.5/MWh price of the PPA. The price of $300 Caps sold during cyclical highs will surge well beyond $16.5/MWh. During cyclical lows, the reverse is true. Consequently, we should expect that a merchant GTs will exhibit a much wider (i.e. riskier) distribution of valuation results.

Model results appear in Fig.14. The first point to note is that gearing levels of ~34% are achievable, with 95th and 5th percentile results of 23% and 46%, respectively. Lower gearing is in-line with expectations. Furthermore, as expected the valuation spans a very wide range, $145m - $235m, with commensurate post-tax equity IRRs of 9-18%. The mid-point valuation is ~$186m with an equity IRR of 12.1%.

Figure 14: Stochastic model results – valuation of fully merchant GT



These results suggest that – while not a riskless investment – the merchant GT is bankable, albeit with low (arguably un-commercial) levels of gearing, at least by project finance standards.

6. Policy implications and concluding remarks

The consequences of an underweight plant stock in any power system invariably leads to highly adverse market prices and outcomes for consumers. It is for this reason that an assessment of GT investments warrants any focus whatsoever. Certainly, the energy economics literature on energy-only markets is characterised by concerns vis-à-vis resource adequacy and the timely investment of peaking plant. Such concerns extend beyond the literature – a rising number of jurisdictions with energy-only markets have been supplemented with administratively coordinated 'strategic reserves' (see Holmberg and Tangeras, 2023; Neuhoff et al., 2023).

In Australia, the NEM's *capacity mechanism equivalent* is the forward market for $300 Caps. It is to be noted that from an industrial organisation perspective, there are no 'pure play peaking GT firms' in the NEM. GT investments have – in almost all instances – been originated by integrated merchant utilities, viz. the Gen-tailers, or renewable firms seeking to integrate firming assets with spot-exposed wind and solar portfolios. The reason for this is the benefits of GT integration exceed stand-alone or 'sum-of-parts' valuations (see Simshauser, 2020, 2021), which in turn can be explained by economies of coordination, bounded rationality and other market imperfects articulated in Oliver Williamson's extensive works on transaction cost economics.

At the time of drafting, Cap prices appeared to be sending near-term entry signals (recall Fig.12). Price forecasts from large utility planning models – while reflecting averages well – may not always capture volatility. This is particularly the case in energy-only markets such as the NEM which has, as Billimoria et al. (2025) describes, *'full strength pricing'* (i.e. with a $20,300/MWh ceiling, it is amongst the highest in the world).

In this article, an alternate modelling framework for assessing peaking investments was presented. This alternate approach, which lies somewhere between structural LP models and Monte Carlo stochastic methods, involved block bootstrapping historic market prices. Results were then utilised by a stochastic unit commitment model. This combination created a broad array of forecast spot and forward prices, GT production, fuel costs and expected gross profits. Viewed through this modelling lens along with a distribution of GT plant valuations from the PCF Model – which captured the manifestly random nature of peaking duties – a merchant GT in a transitioning energy-only market appeared viable.

The practical evidence is however that the NEM has been surprisingly slow with GT developments, raising questions as to why the dearth of proposals from the integrated merchant utilities? In the Australian context, three policy-related parameters seem relevant:

1. GTs are fired on natural gas (fossil fuel) and therefore face a level of policy uncertainty;

2. The Commonwealth Government's recent policy for capacity investment specifically excluded GTs, instead preferencing short duration batteries, amplifying the perceptions of 1.; and

3. In the NEM's three largest regions, scheduled coal plant closures have been delayed, or are perceived to be at risk of being delayed, through direct sub-national government interventions.

Each will weigh on GT investor sentiment to varying degrees:

1. In spite of the achievements of energy transition thus far, Australian investors have virtually no experience with a bipartisan, integrated energy & climate policy architecture (Crowley, 2021; Nelson et al., 2025). Climate policy has been the subject of persistent dynamic inconsistency with seven attempts at pricing carbon, only one of which was temporarily successful (Crowley, 2017; Simshauser and Tiernan, 2019). On the other hand, peaking GTs exhibit low production duties, and their capacity is critical when required. Switching to very high-cost renewable fuels, or imposing a very high carbon price on emissions, does not appear to reduce the fundamental capacity requirement as Gilmore et al., (2023) demonstrate.

2. There is no theoretically grounded reason in energy economics or in energy policy as to why GTs should be excluded from a government underwritten capacity investment scheme. The existing scheme focuses on utility-scale batteries.

   Batteries are a critical resource for transitioning power systems and particularly in Australia due to high solar resources. In charging mode, they help reduce renewable plant curtailment rates and in generation mode, they shift low cost (and otherwise spilled) energy to evening peaks.

   An influx of underwritten batteries will reduce GT operating duties. But they are unlikely to replace the fundamental 'capacity need' for unconstrained primary generating capacity (see Mountain, 2025). Batteries don't create energy, they shift it, and therefore cannot resolve structural renewable energy shortages during critical event days or winter periods (recall Fig.3). Nor can short-duration batteries defend $300 Caps at nameplate capacity. Recall historic price data revealed more than 100 events where prices exceeded $300 for more than 6 hours contiguously. It is to be noted $300 Caps are critical derivative instrument for Retail Suppliers, and therefore consumers, and for now, GTs remain the benchmark.

3. Of all the entry frictions facing GTs, delays to coal plant closures does present as a material problem. That coal closure delays are being contemplated at all reflects a legitimate government response to entry frictions (planning and environmental delays, market conditions, network access etc) currently being encountered by all generation technologies.

   Nonetheless, the sheer scale of coal-fired generators (in/out) makes them a significant variable in any investment equation – creating a *'chicken and egg'* policy problem. Three years of visible $300 Cap premiums in forward markets may not convince a Board of Directors to make a 30+ year GT investment commitment when utility planning models are telegraphing a material lack volatility because of coal closure delays. Being a semi-strong efficient market, the forward prices for $300 Caps will fall materially the moment any coal closure delay is announced (or ahead of public announcement if 'pre-decision' private information begins to circulate).

From a power system planning perspective, Australia's rapidly aging coal fleet means the requirement for an emergent flexible GT fleet is understood. And the forward market for $300 Caps appears to reflect this requirement. The modelling architecture set out in this article suggests the conditions necessary are currently present – at least for merchant integrated utilities capable of extracting the gains from such plant. It would seem the primary risk is government concerns over entry frictions, thus creating a problem with a circular reasoning.

7. References

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Appendix I: Project and Corporate Finance Model

In the PCF Model, prices and costs increase annually by a forecast general inflation rate (CPI).

$$\pi_j^{R,C} = \left[1 + \left(\frac{CPI}{100}\right)\right]^j , \tag{A1}$$

Energy output q_j^i from each plant (*i*) in each period (*j*) is a key variable in driving revenue streams, unit fuel costs, fixed and variable Operations & Maintenance costs. Energy output is calculated by reference to installed capacity k^i, capacity utilisation rate CF_j^i for each period *j*. Plant auxiliary losses Aux^i arising from on-site electrical loads are deducted. Plant output is measured at the Node and thus a Marginal Loss Factor MLF^i coefficient is applied.

$$q_j^i = CF_j^i.k^i.(1 - Aux^i).MLF^i, \tag{A2}$$

A convergent electricity price for the i^{th} plant $(p^{i\varepsilon})$ is calculated in year one and escalated per eq. (1). Thus revenue for the i^{th} plant in each period *j* is defined as follows:

$$R_j^i = (q_j^i.p^{i\varepsilon}.\pi_j^R), \tag{A3}$$

If thermal plant are to be modelled, marginal running costs need to be defined per Eq. (4). The thermal efficiency for each generation technology ζ^i is defined. The constant term '3600'[13] is divided by ζ^i to convert the efficiency result from % to kJ/kWh. This is then multiplied by raw fuel commodity cost f^i. Variable Operations & Maintenance costs v^i, where relevant, are added which produces a pre-carbon short run marginal cost. Under conditions of externality pricing CP_j, the CO_2 intensity of output needs to be defined. Plant carbon intensity g^i is derived by multiplying the plant heat rate by combustion emissions $\dot{g}^i$ and fugitive CO_2 emissions $\hat{g}^i$. Marginal running costs in the j^{th} period is then calculated by the product of short run marginal production costs by generation output q_j^i and escalated at the rate of π_j^C.

$$\vartheta_j^i = \left\{\left[\left(\frac{\left({3600}/{\zeta^i}\right)}{1000}.f^i + v^i\right) + (g^i.CP_j)\right].q_j^i.\pi_j^C \middle| g^i = (\dot{g}^i + \hat{g}^i).\frac{\left({3600}/{\zeta^i}\right)}{1000}\right\}, \tag{A4}$$

Fixed Operations & Maintenance costs FOM_j^i of the plant are measured in \$/MW/year of installed capacity FC^i and are multiplied by plant capacity k^i and escalated.

$$FOM_j^i = FC^i.k^i.\pi_j^C, \tag{A5}$$

Earnings Before Interest Tax Depreciation and Amortisation (EBITDA) in the j^{th} period can therefore be defined as follows:

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[13] The derivation of the constant term 3,600 is: 1 Watt = 1 Joule per second and hence 1 Watt Hour = 3,600 Joules.

$$EBITDA_j^i = \left(R_j^i - \vartheta_j^i - FOM_j^i\right), \tag{A6}$$

Capital Costs $\left(X_0^i\right)$ for each plant *i* are Overnight Capital Costs and incurred in year 0. Ongoing capital spending $\left(x_j^i\right)$ for each period *j* is determined as the inflated annual assumed capital works program.

$$x_j^i = c_j^i . \pi_j^C, \tag{A7}$$

Plant capital costs X_0^i give rise to tax depreciation (d_j^i) such that if the current period was greater than the plant life under taxation law (L), then the value is 0. In addition, x_j^i also gives rise to tax depreciation such that:

$$d_j^i = \left(\frac{X_0^i}{L}\right) + \left(\frac{x_j^i}{L-(j-1)}\right), \tag{A8}$$

From here, taxation payable $\left(\tau_j^i\right)$ at the corporate taxation rate (τ_c) is applied to $EBITDA_j^i$ less Interest on Loans $\left(I_j^i\right)$ later defined in (16), less d_j^i. To the extent $\left(\tau_j^i\right)$ results in non-positive outcome, tax losses $\left(L_j^i\right)$ are carried forward and offset against future periods.

$$\tau_j^i = Max\left(0, \left(EBITDA_j^i - I_j^i - d_j^i - L_{j-1}^i\right) . \tau_c\right), \tag{A9}$$

$$L_j^i = Min\left(0, \left(EBITDA_j^i - I_j^i - d_j^i - L_{j-1}^i\right) . \tau_c\right), \tag{A10}$$

The debt financing model computes interest and principal repayments on different debt facilities depending on the type, structure and tenor of tranches. There are two types of debt facilities – (a) corporate facilities (i.e. balance-sheet financings) and (2) project financings. Debt structures available in the model include bullet facilities and semi-permanent amortising facilities (Term Loan B and Term Loan A, respectively).

Corporate Finance typically involves 5- and 7-year bond issues with an implied 'BBB' credit rating. Project Finance include a 5-year Bullet facility requiring interest-only payments after which it is refinanced with consecutive amortising facilities and fully amortised over an 18-25 year period (depending on the technology) and a second facility commencing with tenors of 5-12 years as an Amortising facility set within a semi-permanent structure with a nominal repayment term of 18-25 years. The decision tree for the two Term Loans was the same, so for the Debt where DT = 1 or 2, the calculation is as follows:

$$if\ j \begin{cases} > 1, DT_j^i = DT_{j-1}^i - P_{j-1}^i \\ = 1, DT_1^i = D_0^i . S \end{cases} \tag{A11}$$

D_0^i refers to the total amount of debt used in the project. The split (S) of the debt between each facility refers to the manner in which debt is apportioned to each Term Loan facility or Corporate Bond. In most model cases, 35% of debt is assigned to Term

Loan B and the remainder to Term Loan A. Principal P_{j-1}^{i} refers to the amount of principal repayment for tranche *T* in period *j* and is calculated as an annuity:

$$P_j^i = \left(\frac{DT_j^i}{\left[\frac{1-(1+\left(R_{Tj}^Z+C_{Tj}^Z\right))^{-n}}{R_{Tj}^Z+C_{Tj}^Z} \right]} \middle| z \begin{cases} = VI \\ = PF \end{cases} \right) \tag{A12}$$

In (12), R_{Tj} is the relevant interest rate swap (5yr, 7yr or 12yr) and C_{Tj} is the credit spread or margin relevant to the issued Term Loan or Corporate Bond. The relevant interest payment in the *j*th period $\left(I_j^i\right)$ is calculated as the product of the (fixed) interest rate on the loan or Bond by the amount of loan outstanding:

$$I_j^i = DT_j^i \times (R_{Tj}^z + C_{Tj}^z) \tag{A13}$$

Total Debt outstanding D_j^i, total Interest I_j^i and total Principle P_j^i for the *i*th plant is calculated as the sum of the above components for the two debt facilities in time *j*. For clarity, Loan Drawings are equal to D_0^i in year 1 as part of the initial financing and are otherwise 0.

One of the key calculations is the initial derivation of D_0^i (as per eq.A11). This is determined by the product of the gearing level and the Overnight Capital Cost $\left(X_0^i\right)$. Gearing levels are formed by applying a cash flow constraint based on credit metrics applied by project banks and capital markets. The variable γ in our PF Model relates specifically to the legal structure of the business and the credible capital structure achievable. The two relevant legal structures are Vertically Integrated (VI) merchant utilities (issuing 'BBB' rated bonds) and Independent Power Producers using Project Finance (PF).

$$if\ \gamma \begin{cases} = VI,\ \frac{FFO_j^i}{I_j^i} \geq \delta_j^{VI} \forall\, j \ \left| \frac{D_j^i}{EBITDA_j^i} \geq \omega_j^{VI} \forall\, j \ \right| FFO_j^i = \left(EBITDA_j^i - x_j^i\right) \\ = PF, Min\left(DSCR_j^i, LLCR_j^i\right) \geq \delta_j^{PF}, \forall\, j \ \left| DSCR_j = \frac{\left(EBITDA_j^i - x_j^i - \tau_j^i\right)}{P_j^i + I_j^i} \right| LLCR_j = \frac{\sum_{j=1}^{N}\left[\left(EBITDA_j^i - x_j^i - \tau_j^i\right).(1+K_d)^{-j}\right]}{D_j^i} \end{cases} \tag{A14}$$

Credit metrics[14] $\left(\delta_j^{VI}\right)$ and $\left(\omega_j^{VI}\right)$ are exogenously determined by credit rating agencies and are outlined in Table 2. Values for δ_j^{PF} are exogenously determined by project banks and depend on technology (i.e. thermal vs. renewable) and the extent of energy market exposure, that is whether a Power Purchase Agreement exists or not. For clarity, FFO_j^i is 'Funds From Operations' while $DSCR_j^i$ and $LLCR_j^i$ are the Debt Service Cover Ratio and Loan Life Cover Ratios. Debt drawn is:

$$D_0^i = X_0^i - \sum_{j=1}^{N}\left[EBITDA_j^i - I_j^i - P_j^i - \tau_j^i\right].(1+K_e)^{-(j)} - \sum_{j=1}^{N} x_j^i.(1+K_e)^{-(j)} \tag{A15}$$

At this point, all of the necessary conditions exist to produce estimates of the long run marginal cost of power generation technologies along with relevant equations to solve for the price $\left(p^{i\varepsilon}\right)$ given expected equity returns (K_e) whilst simultaneously meeting the

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[14] For Balance Sheet Financings, Funds From Operations over Interest, and Net Debt to EBITDA respectively. For Project Financings, Debt Service Cover Ratio and Loan Life Cover Ratio.

constraints of δ_j^{VI} and ω_j^{VI} or δ_j^{PF}given the relevant business combinations. The primary objective is to expand every term which contains $p^{i\varepsilon}$. Expansion of the EBITDA and Tax terms is as follows:

$$0 = -X_0^i + \sum_{j=1}^{N}\Big[\big(p^{i\varepsilon}.q_j^i.\pi_j^R\big) - \vartheta_j^i - FOM_j^i - I_j^i - P_j^i - \Big(\big(p^{i\varepsilon}.q_j^i.\pi_j^R\big) - \vartheta_j^i - FOM_j^i - I_j^i - d_j^i - L_{j-1}^i\Big).\tau_c\Big].(1+K_e)^{-(j)} - \sum_{j=1}^{N} x_j^i.(1+K_e)^{-(j)} - D_0^i \qquad \text{(A16)}$$

The terms are then rearranged such that only the $p^{i\varepsilon}$ term is on the left-hand side of the equation:

Let $IRR \equiv K_e$

$$\sum_{j=1}^{N}(1-\tau_c).p^{i\varepsilon}.q_j^i.\pi_j^R.(1+K_e)^{-(j)} = X_0^i - \sum_{j=1}^{N}\Big[-(1-\tau_c).\vartheta_j^i - (1-\tau_c).FOM_j^i - (1-\tau_c).\left(I_j^i\right) - P_j^i + \tau_c.d_j^i + \tau_c L_{j-1}^i).(1+K_e)^{-(j)}\Big] + \sum_{j=1}^{N} x_j^i.(1+K_e)^{-(j)} + D_0^i \qquad \text{(A17)}$$

The model then solves for $p^{i\varepsilon}$ such that:

$$p^{i\varepsilon} = \frac{X_0^i}{\sum_{j=1}^{N}(1-\tau_c).P^{\varepsilon}.\pi_j^R.(1+K_e)^{-(j)}} + \frac{\sum_{j=1}^{N}\Big((1-\tau_c).\vartheta_j^i + (1-\tau_c).FOM_j^i + (1-\tau_c).\left(I_j^i\right) + P_j^i - \tau_c.d_j^i - \tau_c L_{j-1}^i).(1+K_e)^{-(j)}\Big)}{\sum_{j=1}^{N}(1-\tau_c).q_j^i.\pi_j^R.(1+K_e)^{-(j)}} + \frac{\sum_{j=1}^{N} x_j^i.(1+K_e)^{-(j)} + D_0^i}{\sum_{j=1}^{N}(1-\tau_c).q_j^i.\pi_j^R.(1+K_e)^{-(j)}} \qquad \text{(A18)}$$