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Keywords vertical integration, electricity markets, energy-only markets, transaction costs, credit ratings

JEL Classification D23, D24, D25, G34, L94

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Merchant utilities and boundaries of the firm: vertical integration in energy-only markets

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Resource adequacy in energy-only markets is of continual interest to policymakers due to risks posed by incomplete markets. In Australia, resource adequacy has historically been navigated via energy retailer investment commitments in peaking plant capacity. This in turn has been driven by the National Electricity Market's (NEM) very high Market Price Cap (AUD $15,000/MWh). The NEM is now rapidly transitioning with sharply rising levels of utility-scale variable renewable energy, world-record uptake rates of rooftop solar PV by households, and ongoing coal plant closures. Ironically however, investment commitments in peaking plant capacity by the NEM's energy retailers appears to have stalled. This raises the question as to whether the energy retailer model of investing in peaking plant, a pattern which has dominated energy-only markets, has somehow broken down. If so it raises questions of the suitability of the energy-only market design. In this article, peaking plant dynamics are tested using historic NEM data. Specifically, investments in a stand-alone generator, a stand-alone energy retailer and a merged entity are simulated over 16 years of trade under both project finance and corporate financing structures with a focus on credit metrics. Results reveal the canonical merchant peaking plant remains too risky as a stand-alone project financing in an energy-only market. But energy retailer incentives to commit to on-balance sheet financed peaking plant remains, with transaction cost synergies of 13% and investment grade credit quality being contingent on integration.

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1. Introduction

In energy-only markets there are no formal mechanisms or centrally coordinated capacity payments for reserve plant. This raises questions of how fixed and sunk generation costs are recovered and whether such a market is capable of consistently delivering resource adequacy. Forward markets are known to be incomplete vis-à-vis products required to make peaking plant 'bankable' i.e. long-dated Power Purchase Agreements (PPA). Consequently, energy-only market design is of continual interest to policymakers because spot and forward markets are the primary means by which resource adequacy is delivered.

In theory, provided the Value of Lost Load (VoLL) has a tight nexus with stated reliability criteria, there should be no question that adequate plant investments will be delivered by energy-only markets. Declining reserve capacity induces a rising number and intensity of price spike events, and eventually tip the economic calculus in favour of investment commitment. The central question is whether investment commitment occurs on a timely basis, or in response to a crisis. Given the political economy of electricity prices, the latter is not acceptable.

In Australia's National Electricity Market (NEM), the future value of baseload energy is signalled through the forward curve for swaps (i.e. two-way Contracts-for-

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Differences or CfDs) while the future value of capacity is signalled through the forward curve for $300 caps (i.e. a one-way CfDs with a $300/MWh strike price). In this sense, $300 caps are the NEMs equivalent of an organised capacity market, and are very actively traded. As expectations of reliability deteriorate, the price of $300 caps surge beyond peaking plant entry costs, signalling additional plant capacity is required (as Fig.3b subsequently illustrates).

As Finon (2008) explains, the *canonical merchant peaking plant* relied on spot markets and short-term forward contracts for revenues, underpinned by long-dated project finance. However, as Finon also explained the model was intractable in energy-only markets due to missing money or episodes of structural oversupply. Prior research consistently demonstrates stand-alone merchant Open Cycle Gas Turbine (OCGT) plant in the NEM is *unbankable* (Simshauser, 2008, 2020; Nelson and Simshauser, 2013; Tian, 2016). The only feasible solution for a stand-alone OCGT plant is one underwritten by a long-dated PPA but there is active forward market in such instruments (i.e. incomplete markets).

Yet the practical evidence from Australia's NEM is that with few exceptions resource adequacy has been delivered under a wide array of market conditions for more than two decades. The means by which peaking plant entry has occurred is through portfolio investments, >75% of gas turbine capacity was the product of investment commitment by energy retailers.

Model results in Tian (2016) and Simshauser et al. (2015) confirm these dynamics vis-à-vis NEM energy retailers by identifying the existence of material portfolio synergies between generation and retail which tip the economic calculus in favour of timely investment commitment. More recently, these same dynamics were identified between merchant stochastic (intermittent) generators and OCGT (firming) capacity in the NEM (Simshauser, 2020).

Despite these dynamics, an exception emerged in Australia's NEM during the 2016-2020 'investment supercycle'. The supercycle was characterised by a sharp upward drift in spot and forward electricity prices following the sudden exit of multiple coal plants (i.e. ~5000MW). The market responded with record levels of renewable generation investment commitments, viz. solar and wind. But intriguingly, very few gas turbine commitments occurred. Three OCGT investment commitments were made by merchant stochastic generators (i.e. firming capacity) and one OCGT investment by the NEMs traditional energy retailers. Consequently, one NEM jurisdictional government (South Australia) was compelled to step into the market to underwrite the rapid deployment of battery storage and OCGT plant, and the Independent Market Operator used emergency powers to contract resources in neighbouring Victoria.

A logical line of inquiry that follows is whether the vertical model of investment in peaking plant by energy retailers has somehow *'run its course'* and is no longer tractable? European research tends to suggests rising levels of renewables and merit order effects have made investment in gas peaking plant increasingly unprofitable (see Traber and Kemfert, 2011; Hach and Spinler, 2016; Praktiknjo and Erdmann, 2016; Höschle *et al.*, 2017; Bublitz *et al.*, 2019; Milstein and Tishler, 2019; Gugler *et al.*, 2020; Liebensteiner and Wrienz, 2020). In the NEM, there has indeed been a change in the relative pattern of prices due to merit order effects, and the nature of retail load served has also altered significantly given Australian household take-up rates of rooftop solar PV. Another possible reason for stalled investment commitments by energy retailers may be rising levels of government interventions in the market. Either way, if the vertical synergies that historically existed have evaporated, it has material implications for policymakers vis-à-vis the appropriateness of the NEM's institutional energy-only market design.

The purpose of this article is to extend analysis presented in Simshauser et al. (2015) in order to analyse motives for energy retailer investment in peaking plant. A suite of models and use of historic, granular 30-minute data from the NEM's spot, forward and retail electricity markets are combined to simulate and value peaking plant in the Queensland region over a 16-year period 2004/05-2019/20, and necessarily occurs from two distinct perspectives:

I. as a stand-alone generator, and

II. as an integrated investment by an energy retailer.

The period selected (i.e. 2004/05-2019/20) represents the complete window of data for the task at hand[1] and incorporates multiple business cycles thus producing rich insights into the economics of reserve plant capacity in an energy-only market setting with a high VoLL (at AUD$15,000/MWh, among the highest in the world). And, selecting the Queensland region is important as one-in-three households have installed solar PV units, and, has historically been one of the NEM's *'tougher neighbourhoods'* from a wholesale & retail market perspective. Consequently, if peaking plant investment has become intractable, Queensland data is likely to reveal the source.

Key findings are as follows. First, model results reveal non-trivial transaction costs exist when energy retailers are partitioned from peaking plant investments. This trend holds before- and after- the run-up in customer rooftop solar PV. Therefore, material changes in the load shape and retailer load served *do not* explain reduced investment activity by energy retailers. Second, results reveal combining OCGT plant with an energy retailer continues to exhibit material transaction cost synergies (i.e. ~13% cost subadditivity). Third, credit quality of a stand-alone energy retailer is sub-investment grade, but when integrated with OCGT plant exhibits investment-grade metrics regardless of the change in the relative pattern of prices. Consequently, results suggest the synergies which induced historical vertical investments remain in-tact. The stalling of peaking investment commitments by energy retailers observed during the 2016-2020 supercycle must therefore be explained by other variables, most likely ongoing (and capricious) government interventions in the market.[2]

This article is structured as follows. Section 2 provides a review of relevant literature. Section 3 introduces the models and data. Sections 4-5 present results. Policy implications and conclusions follow.

2. Review of Literature

It is helpful to review the origins of electricity industry restructuring, resource adequacy and integration motives in energy-only markets.

2.1 Origins of restructuring

Electricity supply industry restructuring[3] vis-à-vis power generation can be traced as far back as Weiss (1973). For most of the 20th Century the electricity supply industry was one of the leading sectors of the economy measured by productivity and technology development but by the 1980s performance had deteriorated in US, Great

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[1] The NEM commenced in 1998 and spot market data is available from 1998-2004. However, reliable forward contract data is only available from 2004 onwards.

[2] It is beyond the scope of this article to survey these. But prominent candidates include the Commonwealth Government's Underwriting New Generation Investment scheme (which precludes large energy retailers), the threat of Commonwealth Ministers to use their own energy business (Snowy Hydro) to invest in OCGT capacity if large energy retailers do not, a series of (sub-national) government-initiated CfD schemes in Victoria and in New South Wales designed to flood their jurisdictional markets with new renewable capacity.

[3] For an excellent discussion of the diversity of industrial organisation within the electricity industry prior to the reforms, see Schmalensee (2021).

Britain and Australia amongst others (Joskow, 1987; Kellow, 1996; Newbery and Pollitt, 1997). To generalise, the industry was characterised by material overcapacity and rising prices (Pierce, 1984; Hoecker, 1987). Further, utility service boundaries were frequently economically meaningless (Fairman and Scott,1977). The objective of restructuring was therefore clear, and the basis for doing so was that economies of integration *'were most likely minimal'* as Landon (1983) explained.

Policies promoting restructuring vertical monopoly utilities could not be faulted on the grounds of scale economies. Limits to scale economies in generation were empirically documented by Christensen & Green (1976) and Huettner & Landon (1978).[4] The first practical electricity market experiment commenced in Chile from 1978[5] (Pollitt, 2004) and the wave of microeconomic reform that swept through western economies during the 1990s frequently produced sizable initial gains. The centrepiece of British and Australian reform programs were vertical and horizontal disaggregation of vertical utilities, the creation of competitive wholesale power pools and retail contestability (Newbery, 2005, 2006).

2.2 Resource adequacy

Economic theory and power system modelling had long demonstrated organised spot markets could clear demand reliably and provide investment signals for new plant (Schweppe et al. 1988). But electricity market theory and models were based on equilibrium analysis, and underpinned by an extensive list of explicit and implicit assumptions including unlimited market price caps, perfect capital markets, complete forward markets, limited political/regulatory interference and capital structures able to withstand elongated energy market business cycles (Simshauser, 2010; Arango and Larsen, 2011; Cepeda and Finon, 2011; Bublitz *et al.*, 2019).

In the electricity market blueprint, stand-alone merchant generators selling output into organised spot and forward markets were expected to enter via non-recourse project finance – a form of finance first originated in 1981 and well-suited to capital-intensive generation plant (Nelson and Simshauser, 2013). However, electricity markets turned out to be much tougher operating environments than originally thought. Electricity markets were typically *off equilibrium* for extended periods (de Vries and Heijnen, 2008; Hirth, Ueckerdt and Edenhofer, 2016) and persistent generator pricing at marginal cost produced inadequate revenues given substantial sunk costs which Cramton and Stoft (2005, 2006) labelled *'the missing money'* (see also Bajo-Buenestado, 2017; Keppler, 2017; Milstein and Tishler, 2019).

Merchant generators faced rigid debt repayment schedules, and therefore theories of organised spot markets suffered from an inadequate treatment of how non-trivial sunk capital costs would be financed (Joskow, 2006; Finon, 2008; Simshauser, 2010; Caplan, 2012). Central to the capital-intensive nature of generating equipment is the role that debt capital plays vis-à-vis investment commitment.[6] Early contributions on these market frictions which focused on the special complexity of peaking plant include Doorman (2000), Besser et al. (2002), Stoft (2002), de Vries (2003), Oren (2003) and Peluchon (2003). Entire editions of academic journals wre subsequently devoted to the topic.[7]

In theory, a high VoLL provides the means by which to bridge equilibrium conditions but it is thought that rival electricity market participants are unable to optimise the

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[4] The key insights were that the average total cost curve for power generation was very flat for a broad range of output, and technology changes (i.e. Combined Cycle Gas Turbine) meant scale-efficient entry was contracting after more than 60 years of expansion (see Joskow, 1987; Hunt and Shuttleworth, 1996; Meyer, 2012a).
[5] As Pollitt (2004) notes, vertical and horizontal restructuring was completed by 1981 and enabling legislation enacted in 1982.
[6] As Newbery (2005) explained, multi-stage economies of integration had been an historically important source of coordination benefit vis-à-vis access to low cost finance given the certainty of forward revenues from captive franchise customers.
[7] See *Utilities Policy* Volume 16 (2008) and *Economics of Energy & Environmental Policy* Volume 2 (2013).

number of VoLL events (Cramton et al. 2013). Further, actions by regulators and System Operators frequently suppress legitimate price signals (Joskow, 2008; Hogan, 2013; Spees, Newell and Pfeifenberger, 2013; Leautier, 2016).

Yet despite these headwinds Australia's NEM has delivered resource adequacy over the past 23 years of market operations with few exceptions – key drivers being the tight nexus between VoLL and the reliability criteria, and vertical re-integration (Simshauser, 2010). A new variable testing this are various forms of random political interventions (Simshauser, 2019; Wood, Dundas and Percival, 2019).

2.3 Motives for energy retailer investment in peaking plant

To simplify a vast literature, there are two schools of thought underpinning motives to vertical integration[8], i). the neoclassical view whereby firms acquire market power (Bain, 1956), and ii). transaction cost theories, which suggests when firms confront significant 'on-market' transaction costs (asset specificity, technical dependencies, bounded rationality, contractual incompleteness, security of supply, regulatory risk and/or asymmetric information and uncertainty) vertical integration is a predictable outcome (Williamson, 1971)[9].

As Joskow (2010) explains, empirical evidence on vertical integration is dominated by transaction cost motives.[10] Transaction cost theory explains when market frictions create hazards for ex-ante investment commitment and ex-post performance, vertical investment achieves more adaptive, sequential decision-making procedures as market conditions change (*cf.* anonymous spot and forward market transactions) (Williamson, 1973). Put simply, internal laws of the firm (e.g. investment in OCGT) are more pliable than contract law (e.g. hedging uncertain peak demand with imperfect instruments).

Conversely, whenever vertical arrangements between energy retailers and generators were temporarily banned or forward commitments suboptimal, wholesale prices exceeded efficient levels (see Newbery, 1998; Green, 1999; Borenstein, Bushnell and Wolak, 2002; Kahn and Joskow, 2002; Mansur, 2007; Bushnell, Mansur and Saravia, 2008; Nillesen and Pollitt, 2011). Mansur 2007 and Bushnell et al (2007) find vertical arrangements have moderating effects on wholesale prices in the PJM market. Analysing New Zealand, Hogan and Meade (2007) find vertical integration to be a more efficient business model through avoided double marginalisation with market power reduced significantly, enhanced wholesale market competition and lower retail prices, as does Guo *et al.*, (2020) in the case of China.[11]

Michaels (2007), Arocena (2008) and Nillesen and Pollitt (2011) explain that when proposals for industry restructuring were emerging, economies of scope through integration should have been of unquestionable interest but surprisingly little empirical evidence existed prior to Kaserman and Mayo's (1991) pioneering work. Their study revealed multi-stage losses from disaggregation was (on average) ~12% across 74 utilities. The research that followed comprises two broad streams, i). analysis of cost subadditivity, and ii). motivations and welfare implications of vertical re-aggregation and some have pursued both (Kwoka and Pollitt, 2010; Meyer, 2012a, 2012b). To summarise a vast literature, virtually all studies confirm the existence of economies of vertical integration (Gilsdorf, 1995; Hayashi, Goo and Chamberlain,

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[8] A vast literature on vertical integration across multiple industries exists Cooper *et al.*(2005), Lafontaine and Slade (2007) and Joskow (2010) provide extensive surveys, covering hundreds of theoretical and empirical studies.
[9] See for example Mansur, 2007; Bushnell, Mansur and Saravia, 2008; Simshauser et al. 2015; Godofredo, de Bragança and Daglish, 2017; Guo *et al.*, 2020.
[10] Indeed as Lafontaine & Slade (2007) note, a vast literature on vertical integration spanning well over 500 articles exists with little empirical evidence supporting the neoclassical view (see also Joskow, 2010).
[11] The basis for these findings and implications for energy markets is well understood – in wholesale markets forward contract volumes are known to be extremely important (Allaz and Vila, 1993). With increasing forward sales commitments generators are less inclined to exercise market power in spot markets (Newbery, 1998; Green, 1999; Mansur, 2007; Bushnell, Mansur and Saravia, 2008; Guo *et al.*, 2020).

1997; Kwoka, 2002; Jara-Díaz, Ramos-Real and Martínez-Budría, 2004; Nemoto and Goto, 2004; Fraquelli, Piacenza and Vannoni, 2005; Arocena, 2008; Fetz and Filippini, 2010; Gugler, Liebensteiner and Schmitt, 2017).[12] And separating generation from energy retailing produces multi-stage cost penalties of 20-40% (Kwoka, 2002; Meyer, 2012b, 2012a; Gugler, Liebensteiner and Schmitt, 2017).[13]

3. Models and data

Resource adequacy in energy markets hinges on sufficient reserve capacity. The subsequent analysis focuses on the tractability of peaking plant investments under a wide array of market conditions and business configurations spanning a 16-year window. Peaking plant is initially analysed as a stand-alone generator (first with project finance, then with corporate finance), and then as a vertical investment by an energy retailer. Valuation models are therefore required for:

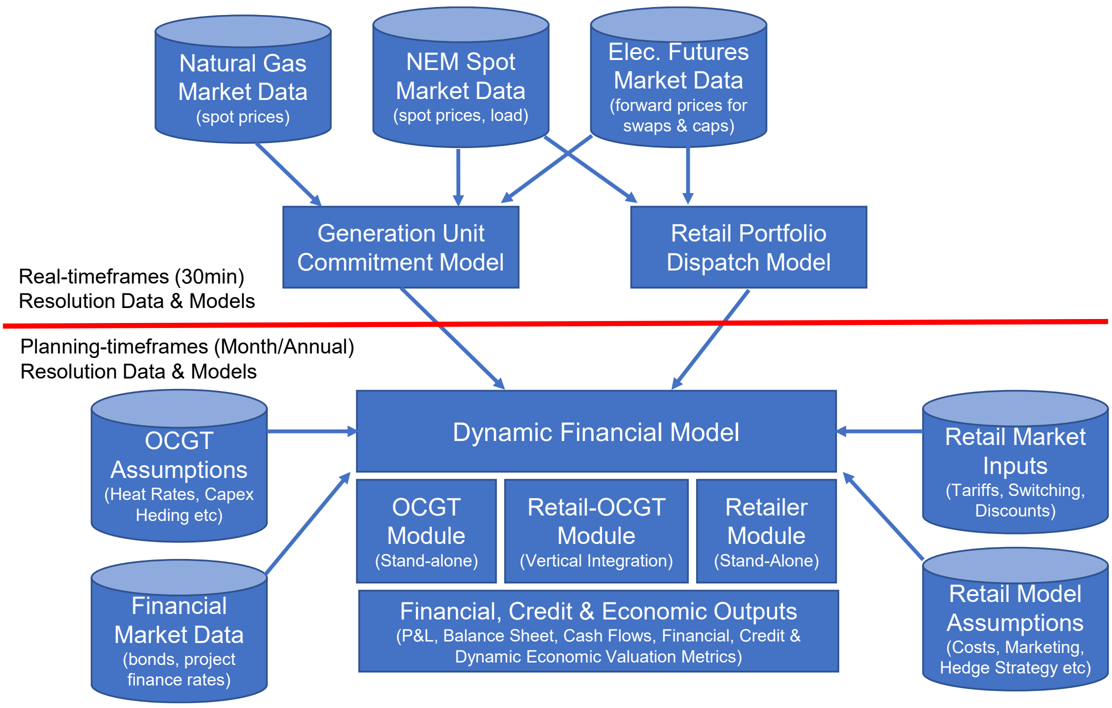
1. a stand-alone project financed OCGT (Section 4.1),
2. a stand-alone balance sheet-financed OCGT plant (Section 4.2),
3. a stand-alone retailer (as a pre-condition to a vertical acquisition, Section 4.3), and
4. an integrated energy retailer-OCGT (Section 4.4).

The task of simulating these business combinations requires the integration of multiple data sources and a suite of economic and financial simulation models. Data and models necessarily traverse operational/real-timeframes (i.e. 30-minute resolution) and planning-timeframes (i.e. annual resolution). Data is drawn from the electricity market, gas market, forward markets and financial markets, and are supplemented with an array of technical engineering and cost data to address residual business assumptions. Integration of the suite of models (*rectangles*) and data sources (*cylinders*) is illustrated in Fig.1. The horizontal line in Fig.1 separates operational (real-time) data and models from financial (planning-timeframe) data and models.

[12] Although Gilsdorf (1995) did not find cost complementarity, he did not preclude the presence of scope and integration economies (in fact several results in his study exhibited as much).

[13] Hayashi et al (1997) estimate between 14-17% gains amongst US utilities. Kwoka (2002 p.664) estimates gains from Generation & Retail integration of 27-42% (median, mean) for across 147 utilities. Nemoto & Goto (2004, p.80) find 0.13-2.97% in Japan, Jara-Diaz et al. (2004, p.1007) find 6.5% plus market costs in Spain. Fraquelli et al (2005, p.306) of 3% for the average sized Italian utility and gains of up to 40% for large operators, Arocena (2008) finds between 1.1-4.9% in Spain. Fetz & Filippini (2010) find vertical economies of 40%+ in Switzerland. Gugler et al. (2017 p.453) find 14-51% (median, mean) across 28 European Utilities.

Figure 1: Data and Modelling Framework



Model logic for the three primary models (i.e. Unit Commitment, Retail Portfolio, Dynamic Financial Models) have been documented in Simshauser (2020a) and Simshauser, Tian and Whish-Wilson (2015) and so are not reproduced here. For convenience, they appear in Appendix I. To summarise their functions, the Unit Commitment Model simulates gas turbine units for each 30-minute trading interval (i.e. historic NEM spot prices) over the 16-year observation period and incorporates technical constraints and non-convexities. The Retail Portfolio Model simulates the energy retailer's 30-minute customer loads from each market segment (i.e. residential, SME, Commercial & Industrial) and dynamically constructs hedge portfolios from the available mix of forward contracts (base swaps, peak swaps, $300 caps) and in vertical integration simulations, by incorporating OCGT plant as a physical hedge. The Dynamic Financial Model takes data from these two operational models (results aggregated to annual resolution) in order to construct business valuations and financial statements for i). a stand-alone OCGT plant, ii). a stand-alone retailer, and iii). a vertically integrated energy retailer and OCGT plant. Suffice to say, the Unit Commitment and Retail Portfolio Models are data intensive with over 280,000 lines of calculations (i.e. 30-minute data over 16 years). And, while the Dynamic Financial Model covers 16 years of annual calculations, its scope is vast – including construction of Profit & Loss, Balance Sheet and Cash Flow Statements, and modules to size and construct project finance and balance sheet financings.

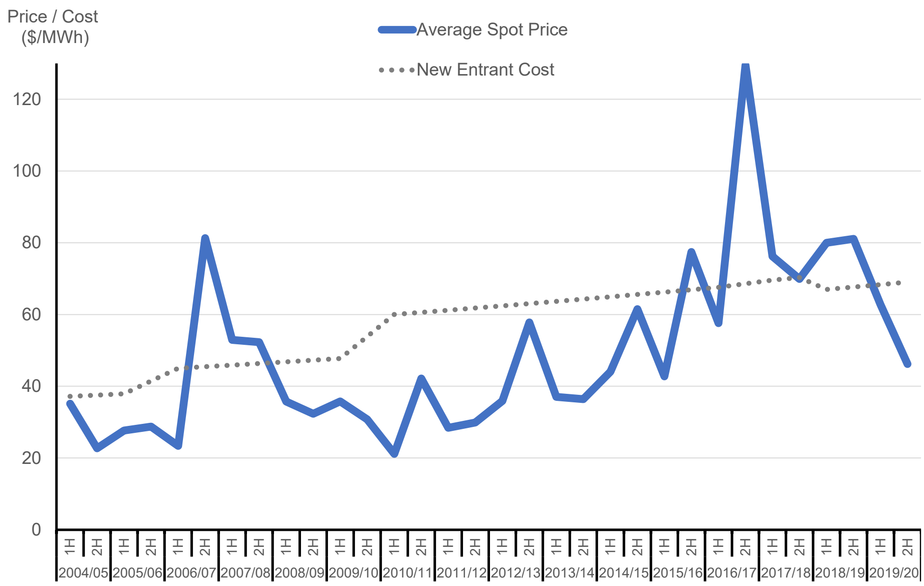
The remainder of this Section is designed to provide an overview of critical data inputs. Doing so helps illustrate the wide array of market conditions facing the OCGT and energy retailer. Residual modelling assumptions and inputs (i.e. required to refine balance sheets, taxation schedules, depreciation schedules etc) have been relegated to Appendix II.

3.1 Spot price of electricity

Central to the subsequent analysis of OCGT plant are conditions in the real-time spot electricity market. Fig.2 presents summary-level (six-monthly) average spot prices (solid blue line) and contrasts estimated generalised new entrant costs (dotted line) derived in Simshauser and Gilmore (2019). From this, one can quickly identify likely periods of profitable, marginal, and deeply unprofitable performance for a stand-alone OCGT plant. A stand-alone energy retailer would face the opposite fate –

compressed margins during elevated price periods in 2007 and 2016-2019, and expanding cumulative margins during low price periods.

Figure 2: QLD Spot Prices[14] vs New Entrant Cost (2004/05 – 2019/20)



Data Source: Australian Energy Market Operator (AEMO), Simshauser and Gilmore (2019)

Tab.1 provides further insight into Queensland spot price data by presenting statistical measures of volatility over the 280,512 trading intervals (i.e. 16-years, 30-minute resolution). The final columns in Tab.1 examine extreme price spike events (i.e. trading intervals exceeding $300/MWh) including the *ex post* 'Fair Value of $300 Caps' which as noted in Section 1, is a very significant NEM forward market derivative instrument, a one-way CfD which signals the value of generation capacity.

Table 1: QLD Spot Prices (2004/05 – 2019/20)

Fin Year	Observations	Average Spot Price	Standard Deviation	Skewness	Kurtosis	Coefficient of Variation	Fair Value of $300 Caps	Number of Price Spikes > $300
	(t)	($/MWh)	($/MWh)	($/MWh)	($/MWh)		($/MWh)	
2004/05	17,520	28.92	109	38	1,797	3.78	3.34	42
2005/06	17,520	28.20	181	35	1,351	6.40	5.59	41
2006/07	17,520	52.34	236	26	753	4.51	9.75	132
2007/08	17,568	52.61	281	25	711	5.34	12.80	77
2008/09	17,520	34.03	106	43	2,487	3.12	2.93	35
2009/10	17,520	33.26	199	31	1,116	5.99	7.42	47
2010/11	17,520	31.66	178	37	1,528	5.63	5.26	37
2011/12	17,568	29.15	46	54	3,436	1.59	0.70	22
2012/13	17,520	67.54	126	22	657	1.86	6.13	168
2013/14	17,520	58.46	106	21	489	1.81	4.56	59
2014/15	17,520	52.79	353	26	803	6.69	18.25	106
2015/16	17,568	60.09	147	17	343	2.44	7.45	86
2016/17	17,520	93.58	331	26	848	3.53	17.75	176
2017/18	17,520	73.05	42	31	1,484	0.57	0.52	9
2018/19	17,520	80.55	39	16	866	0.48	0.20	15
2019/20	17,568	56.01	64	26	1,467	1.15	1.27	26
Total	280,512	51.65	187	37	1,799	3.62	6.49	1,080
2020$		60.65					7.85	

Data Source: AEMO.

3.2 Forward contract prices

As an absolute general conclusion, generators and energy retailers must actively trade in forward contracts to mitigate the worst effects of spot price volatility (energy retailer) or the lack thereof (generator). Trade in NEM forward contracts which runs at 3x physical are dominated by three derivative instruments, viz. baseload and peak period swaps (i.e. two-way CfD) and $300 caps (i.e. one-way CfD).

[14] The spot price series excludes the effect of the Carbon Tax ($23/t) in 2012/13 and 2013/14.

A statistical overview of forward market prices for base swaps, peak swaps and $300 caps (daily trade over 16 years) is presented in Tab.2 (and the model dataset comprising quarterly contract prices appears in Appendix III). Within each of Box A, B and C, the first column presents the ex post final settlement prices (i.e. historic spot price outcomes), the second presents ex ante average traded contract prices, and the third illustrates the average of 'an accumulated portfolio' price (i.e. accumulated progressively over a three-year window[15]).

Table 2: Base, Peak and $300 Cap Prices (2005-2020)

		Box A: Base Prices			Box B: Peak Prices			Box C: $300 Cap Prices		
		Spot	Swaps	Portfolio	Spot	Swaps	Portfolio	Spot >300	$300 Caps	Portfolio
Observations		262,944	16,919	16	143,820	16,919	16	262,944	13,123	16
Average	($/MWh)	51.53	52.29	51.37	62.60	69.38	69.24	6.84	8.62	9.35
Std Deviation	($/MWh)	20.78	14.88	12.09	21.48	18.03	12.08	5.69	4.04	2.34
Coeff. Variation		0.40	0.28	0.24	0.34	0.26	0.17	0.83	0.47	0.25
Min	($/MWh)	28.20	19.40	34.46	33.92	22.50	48.63	0.20	0.05	6.15
Max	($/MWh)	93.58	129.44	72.28	110.97	178.42	88.40	18.25	34.10	13.96

Source: AEMO, ASX.

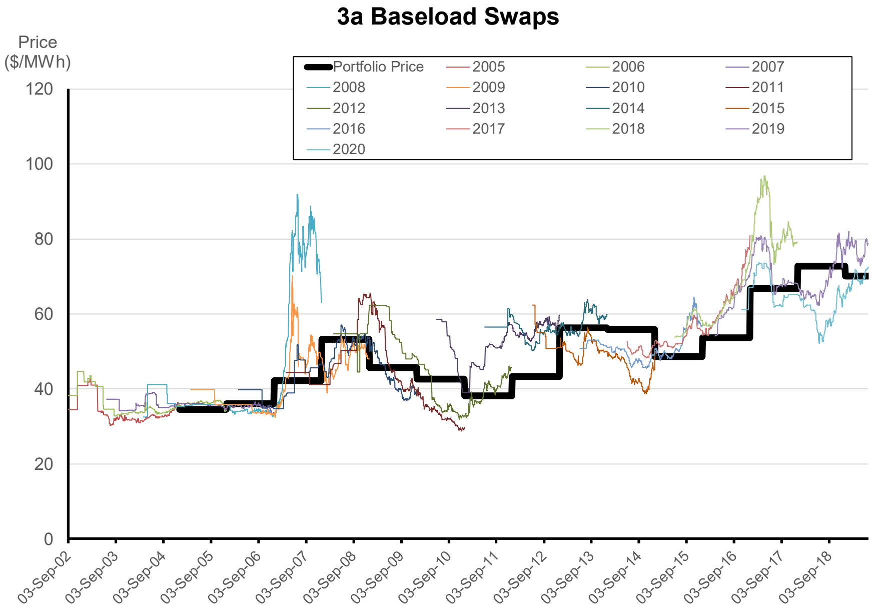
How these results should be interpreted is as follows. Using Box C as example, the first column ("Spot > $300") has an average value of $6.84/MWh – this is the ex-post final spot market settlement value. The second column lists the ex-ante traded value of $300 caps which average $8.62/MWh. Consequently, $300 caps exhibited an average ex ante premium of ~26%. The third column shows the 'accumulated portfolio' of caps which averages $9.35/MWh or a 37% premium to the ex-post spot price. Existence of contract premia for insurance products like $300 caps, which by design are intended to mitigate the worst effects of extreme but highly uncertain price spike events, is to be expected (noting real world consequence of under-hedging can be financial distress and bankruptcy, as the Texas market revealed in early 2021).

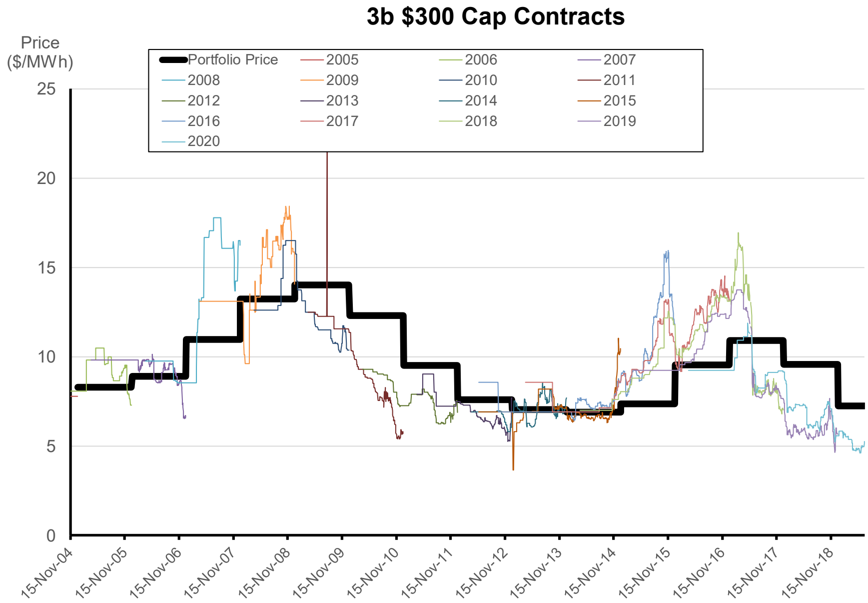
Peak swaps (Box B) traded at $69.38/MWh ex-ante, a ~10% premium to ex-post settlement prices. Base swaps on the other hand exhibit a limited premium and when accumulated as a portfolio, a slight discount to ex post spot prices. The variation in premiums for forward swaps and caps reflects the relative complexity of instrument forecasting.

Run-of-trade baseload swaps (i.e. value of energy) and $300 caps (i.e. value of capacity) for 2005-2020 vintages at daily resolution are illustrated in Fig.3 and provide a good overview of NEM forward market price trends. The accumulated portfolios constructed in the Retail Portfolio Model and used in subsequent business valuation analyses are represented by the solid black line series in Fig.3.

[15] Specifically, the accumulated portfolio involves progressively layering in base swaps into a portfolio over the three-year period leading up to real-time at the pre-set /vanilla hedge portfolio ratio of 20%, 35% and 45% in years n-3, n-2 and n-1 respectively. The same process applies to peak swaps and $300 caps.

Figure 3: Forward Contract Prices (2005-2019, nominal dollars)





Source: ASX.

3.3 Energy retailer

Tab.3 presents critical assumptions associated with the energy retailer being simulated. Retailer formation is assumed to be a privatisation event with initial valuations derived from actual reported NEM 'Merger and Acquisition' (M&A) metrics (outlined in Simshauser et al. 2015). Indeed, the energy retailer modelled is loosely based on an actual Queensland privatisation transaction.

Selecting an appropriately sized energy retailer to model was bounded by two considerations, i). sufficiently large to warrant vertical investment in OCGT plant, and conversely, ii). sufficiently small as to not possess market power. These boundaries were selected to ensure subsequent modelling results are tractable vis-à-vis transaction cost motives of vertical integration (*cf.* neoclassical motives of acquiring market power).

Tab.3 highlights energy retail Total Retail Load commences at 4485GWh. This was constructed by taking ~20% of the Queensland mass market (i.e. residential load and SME customer segments with 2123GWh and 910GWh, respectively) and a 5% share of the Commercial & Industrial (C&I) customer segment (1452GWh). Portfolio Maximum Demand in 2004/05 equates to 778MW. For context, Queensland power system energy demand is 54,000GWh with maximum demand of 10,000MW. NEM energy demand is 185,000GWh and ratcheted maximum demand is 35,000MW. Consequently, the energy retailer modelled has a NEM market share of ~3%.

Table 3: Energy retailer assumptions - 2004/05

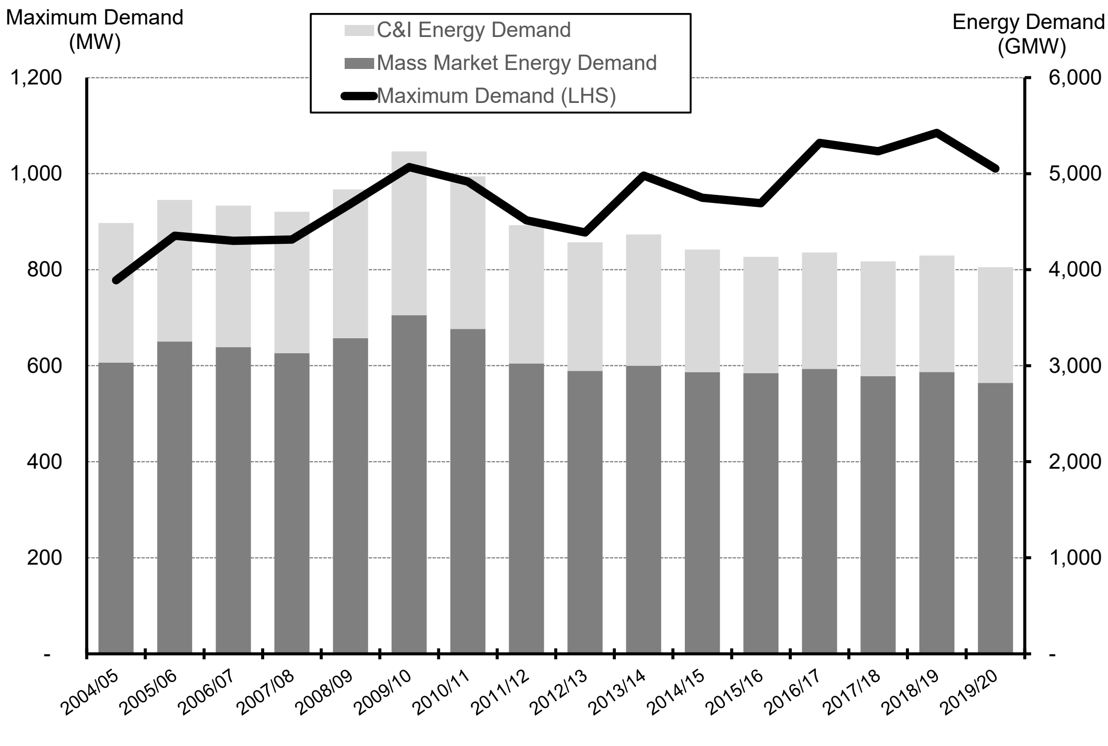
Energy Retailer (QLD)			2004/05
Customer Data			
	Residential Customers		288,241
	SME Customers		41,177
	Residential Load	(GWh)	2,123
	SME Load	(GWh)	910
	C&I Load	(GWh)	1,452
	Total Retail Load	(GWh)	4,485
	Mass Mkt Max Demand	(MW)	647
	C&I Maximum Demand	(MW)	285
	Portfolio Max Demand	(MW)	778
Acquisition Values			
	Mass Market Customers	(per cust)	$800
	C&I Customers	($/MWh)	1.50
	Acquisition Price	($m)	265.7
	65% of which is Goodwill	($m)	172.7

Sources: AEMO, Simshauser et al. (2015), Tian (2016).

3.4 16-year evolution of energy retailer customer load

Fig.4 provides an overview of the evolution of annual customer loads over the 16-years, 2004/05-2019/20. This overview is important – it highlights the changing nature of customer load – becoming 'peakier' due to mass uptake of rooftop solar PV systems from ~2010. In Fig.4, the energy retailer's portfolio maximum demand (MW, line-series, LHS axis) trends upwards consistent with growth in customer numbers per Tab.4. Conversely, portfolio energy demand (GWh, bar-series, RHS axis) is deteriorating.

Figure 4: Retail Customer Load (2004/05-2018/19)



Tab.4 presents annual retail portfolio load data and highlights the extent of Portfolio Load Factor deterioration, from 0.66 to 0.45 over the 16-year window. This means load is becoming harder to forecast, and suitable hedge portfolios are becoming harder to construct. Prima facie, this may favour vertical arrangements.

Table 4: Retail Customer Load (2004/05-2018-19)

Fin Year	Observations	Mass Market* Customer Numbers^	Average Residential Load*	Total Mass Market Energy Demand	Commercial & Industrial Demand	Portfolio Energy Demand	Portfolio Maximum Demand	Portfolio Load Factor
	(t)		(kWh)	(GWh)	(GWh)	(GWh)	(MW)	
2004/05	17520	329,419	7,366	3,033	1,452	4,485	778	0.66
2005/06	17520	334,943	7,767	3,252	1,474	4,726	871	0.62
2006/07	17520	339,804	7,519	3,194	1,473	4,667	860	0.62
2007/08	17568	347,263	7,210	3,130	1,474	4,603	863	0.61
2008/09	17520	352,325	7,464	3,287	1,549	4,836	937	0.59
2009/10	17520	360,332	7,824	3,524	1,707	5,231	1,014	0.59
2010/11	17520	365,196	7,410	3,383	1,589	4,971	983	0.58
2011/12	17568	372,261	6,497	3,023	1,440	4,463	903	0.56
2012/13	17520	378,872	6,219	2,945	1,341	4,286	878	0.56
2013/14	17520	382,051	6,280	2,999	1,367	4,366	996	0.50
2014/15	17520	387,671	6,053	2,933	1,276	4,209	950	0.51
2015/16	17568	393,499	5,939	2,921	1,213	4,134	938	0.50
2016/17	17520	399,005	5,947	2,966	1,213	4,179	1,064	0.45
2017/18	17520	405,796	5,699	2,891	1,196	4,087	1,046	0.45
2018/19	17520	419,234	5,753	2,934	1,213	4,147	1,085	0.44
2019/20	17,568	425,522	5,651	2,821	1,204	4,025	1,011	0.45

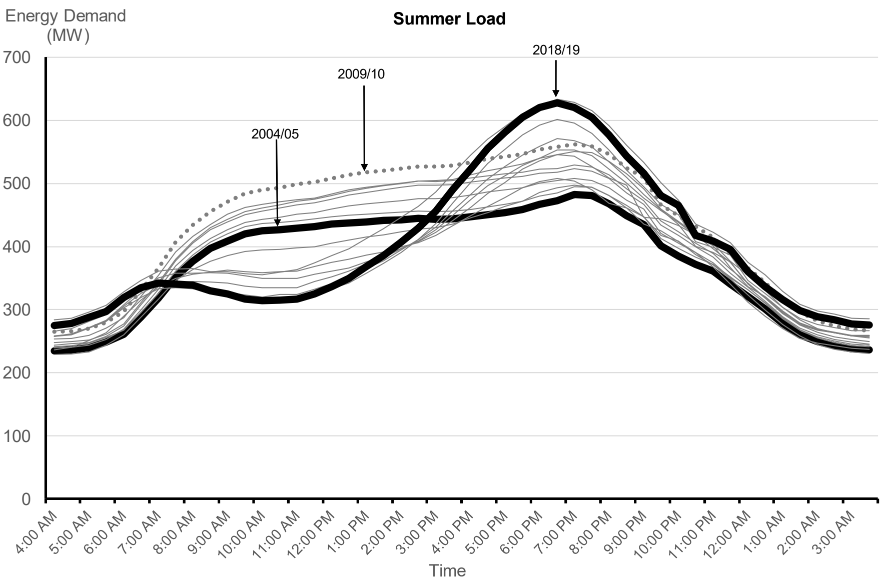
* Mass Market comprises Residential Households and the SME sector. The average SME customer is 3x the size of the average Residential household.

^ Residential customer numbers commence at 288,242 and SME customer numbers commence at 41,177.

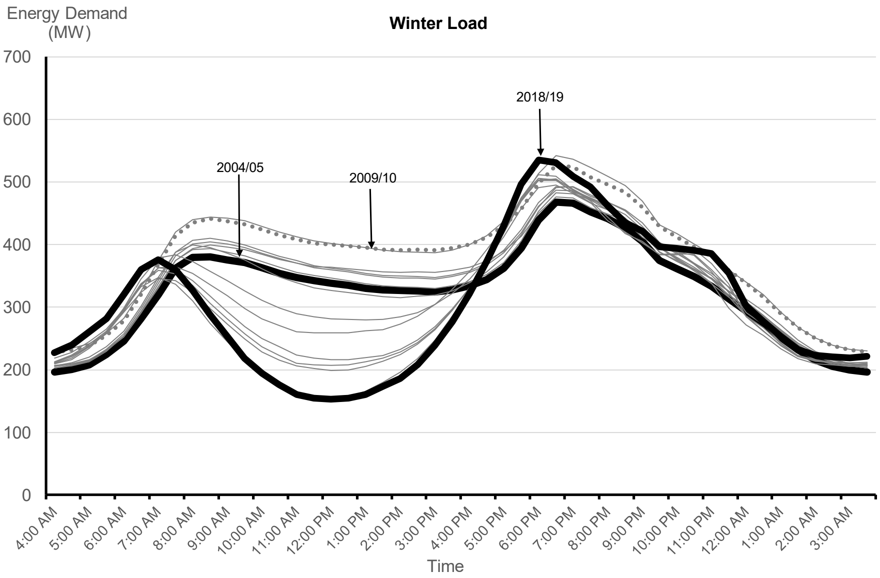
Data Sources: ESAA, AEC, AEMO, QCA.

Structural changes in load are best explained through examination of summer and winter diurnal aggregate final demand charts for the *mass market segment*[16]. In Fig.5, average daily load (30-minute resolution) during summer and winter from 2004/05-2019/20 is illustrated. Average load visibly rises from 2004/05- 2009/10 but thereafter begins to contract. Peak loads rise throughout the 16-year period. This *hollowing-out* of daytime customer loads from 2009/10 is the result of sharply rising levels of 'behind-the-meter' rooftop solar PV. Overall household consumption is increasing, but the component served by the electricity network is contracting.

Figure 5: Mass Market Average Summer & Winter Load (2004/05 – 2019/20)



[16] In the NEM, the mass market is defined as residential and SME customer segments.

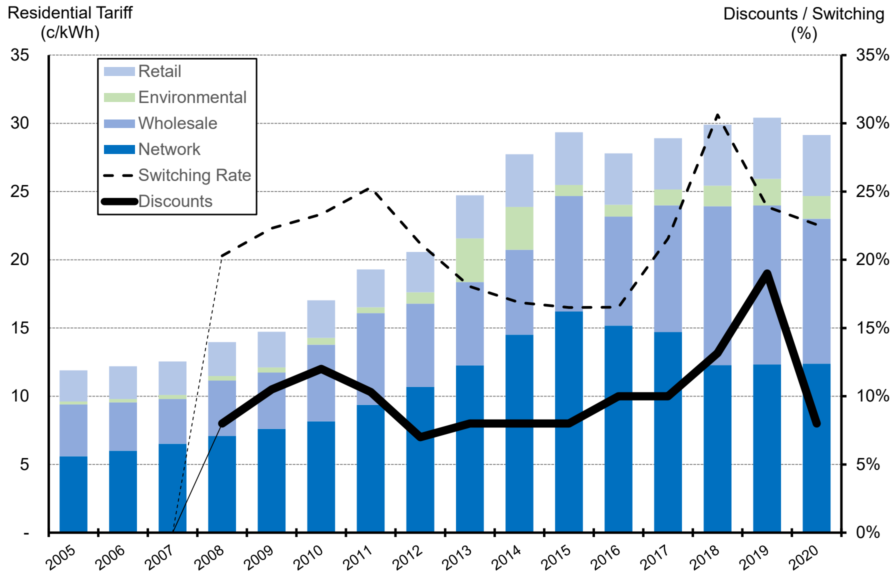


Data Source: ESAA, AEMO, AEC.

3.5 Retail tariffs, discounts & switching rates

Annual retail tariff data has been drawn directly from Queensland Competition Authority (QCA) annual tariff determinations (i.e. the regulated tariff cap for mass market customer segments, outlined in Appendix II)[17]. Were it not for retail contestability in 2008, calculating energy retailer revenues would be a straightforward exercise of multiplying energy consumption (Tab.4) by the two part tariff set by the QCA, the average of which is presented in Fig.6.

Figure 6: Residential tariffs, product discounts and customer switching rates



Data Sources: QCA, Simshauser (2014), AER, AEMO.

Modelling of customer revenues must account for contestable market activity, viz. product discounts and customer switching. When modelling the energy retailer, the market average customer discount (solid line series, RHS axis) is applied to newly acquired customers (i.e. the switching rate, dashed line series, RHS axis) over a rolling two-year window.

Incorporating contestability in modelling has the effect of reducing energy retailer profit in two ways. First, discounts applied against the regulated tariff cap reduce

[17] Retail market tariffs were deregulated by the Queensland Government in 2016, only to be re-regulated by the Commonwealth three years later. To simplify the present analysis, the regulated price cap is assumed to prevail throughout the entire 16-year period.

revenues (but necessary, to retain market share). Second, energy retailer costs increase through marketing and customer acquisition expenditures (Appendix II).

3.6 Overview of the OCGT peaking generator

Tab.5 presents critical assumptions associated with establishment of an OCGT generator. As with the energy retailer, the OCGT selected was based on a real gas turbine built in Queensland in 2005, with plant size (540MW) initially bounded by two considerations, i). of sufficient scale to cover the energy retailer's uncertain peak load, and ii). sufficiently small as to *not* possess inherent/structural market power. These boundaries were again selected to ensure model results are tractable vis-à-vis transaction cost motives of vertical integration (*cf.* neoclassical motives of acquiring market power). Plant size sensitivities are also explored in Section 5.2.

To simplify modelling, business formation is assumed to be the product of a $459m M&A event with quintessential valuation metrics being assumed construction costs of $850/kW, consistent with observed NEM new entrant plant cost data in 2004/05 as reported in Simshauser et al. (2015) and Tian (2016).

Table 5: Queensland OCGT Assumptions in 2004/05

Open Cycle Gas Turbine (OCGT)			
	Unit Size	(MW)	60-240
	Number of Units		3
	Capacity	(MW)	180-720
	Caital Cost	($/kW)	850
	Acquisition Prie	($m)	153-612
Operations			
	Annual Availability	(%)	94.0
	Thermal Efficiency	(%)	31.9
	Heat Rate	(GJ/MWh)	11.3
	Unit Fuel Cost*	($/GJ)	2.91
	Variable O&M	($/MWh)	3.00
	Fixed O&M	($/MW/a)	10,000
	Major Inspections	($m)	15.0
	Useful Life	(Yrs)	40
	Taxation Life	(Yrs)	30

* 10 Yr Gas Supply Agreement, then spot gas prices.

3.7 Gas market data

Gas prices are a key dynamic input for any OCGT plant valuation. In Australia's NEM, all gas-fired plant built prior to 2011 commenced operations with long-dated Gas Supply Agreements (10-15 years duration) as Nelson and Simshauser (2013) explain. This was driven by project banks and covenant requirements regarding fuel supply security given the (then) absence of a spot market for natural gas. Tab.5 highlights an initial gas price of $2.91/GJ – consistent with the $2.80 - $3.00/GJ price range reported by the Australian Competition & Consumer Commission (see ACCC,2018). A spot gas market was subsequently established in Queensland from 2011/12 (Tab.6) and the OCGT plant is assumed to revert to the spot market from 2013/14 (Fig.7).

Tab.6 presents the 10-year contract price and spot gas price statistics from 2011/12-2019/20. The final two columns in Tab.6 present 'Spark Spreads' for baseload Combined Cycle Gas Turbine (CCGT) and peaking OCGT, respectively.

Table 6: QLD gas prices (2004/05-2019/20)

	10 Year Contract Price ($/GJ)	Brisbane Short Term Trading Market Spot Price ($/GJ)	Std. Dev. ($/GJ)	Coeff. Var.	Max Price ($/GJ)	Min Price ($/GJ)	Spark Spread CCGT* ($/MWh)	OCGT^ ($/MWh)
2004/05	2.93						8.38	1.21
2005/06	3.01						7.10	7.94
2006/07	3.13						30.44	39.81
2007/08	3.24						29.96	32.11
2008/09	3.38						10.35	7.40
2009/10	3.46						9.02	9.92
2010/11	3.57						6.64	3.21
2011/12	3.67	3.44	0.45	0.13	4.58	0.00	5.06	-4.83
2012/13	3.73	5.83	0.84	0.14	8.15	4.55	17.53	-6.95
2013/14	3.82	4.72	1.07	0.23	6.75	2.73	16.21	-6.86
2014/15		2.33	0.97	0.41	5.00	0.32	36.46	41.43
2015/16		4.35	1.21	0.28	8.00	1.77	29.64	19.80
2016/17		8.27	1.91	0.23	12.44	4.94	35.72	18.19
2017/18		7.32	0.60	0.08	9.80	6.43	21.81	-4.57
2018/19		9.49	0.56	0.06	10.50	8.28	14.12	-19.72
2019/20		6.00	1.46	0.24	8.77	3.29	14.00	-8.84

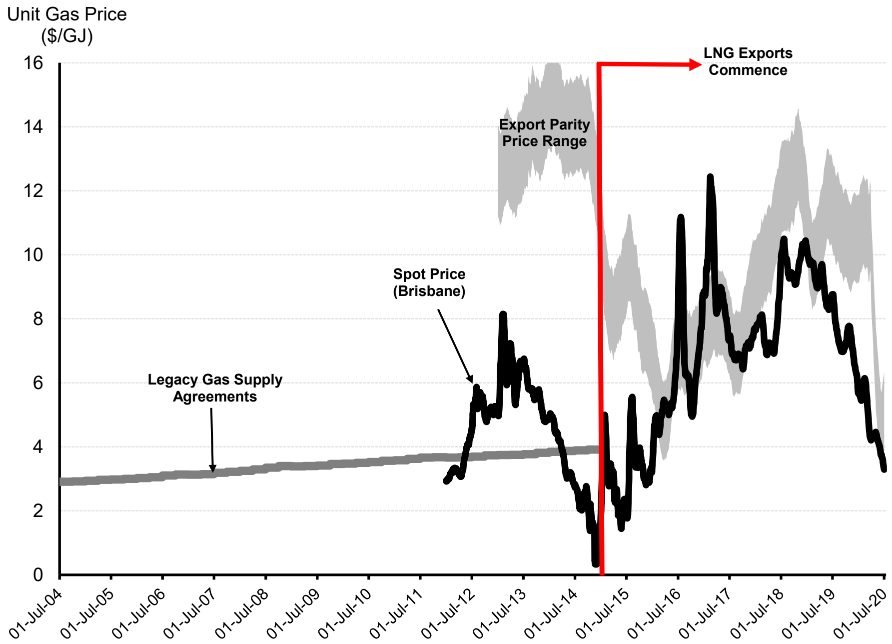
* CCGT Spark Spread: Average Annual Spot Price - (Gas Price x CCGT Heat Rate 7GJ/MWh). Gas spot prices used from 2011/12.

^ OCGT Spark Spread: Average Annual Peak Spot Price - (Gas Price x OCGT Heat Rate 11.3 GJ/MWh). Gas spot prices used from 2011/12.

Data Source: ACCC (2018), AEMO, ABS.

Fig.7 illustrates a distinct rise in spot gas prices from 2015/16. This was driven by a fleet of LNG export facilities being commissioned in the Queensland region. The LNG terminals had the effect of linking NEM-region gas prices to international export prices for the first time.

Figure 7: QLD gas prices (2004/05 – 2019/20)



Data Source: AEMO, Table 4.

4. Model Results

It is useful to frame the underlying problem of resource adequacy in energy-only markets by first examining (and discarding) the prospect that the stand-alone, merchant OCGT plant is 'bankable'. The inherent difficulty with the merchant model proved to be 'missing money' and the extent of volatility (or the lack thereof) during overcapacity.

4.1 Stand-Alone Merchant OCGT – Project Finance

Historic data and simulation models (Section 3, Appendices I-III) were combined with project finance parameters contained in Tab.7 to analyse the economic performance of the reference case 540MW OCGT. Tab.7 parameters have been drawn from the

Australian capital markets survey data documented in Simshauser (2009) and Nelson and Simshauser (2013), and reflect those typical of a NEM power project financing in 2005.

Table 7: Merchant OCGT Project Financing

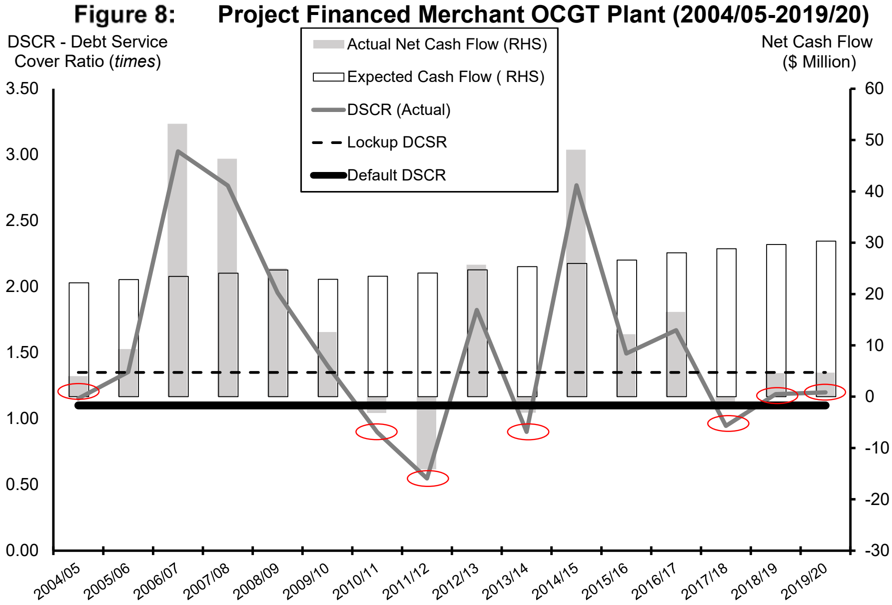
Project Finance			Debt Sizing Parameters		
- Post Tax Equity (Er)	(%)	12.00	- DSCR	(times)	1.80
Interest Rates in 2004			- Lockup	(times)	1.35
- Term Loan A 12Yr Swap	(%)	6.18	- Default	(times)	1.10
- Term Loan A Spread	(bps)	180	- Term Loan A	(Yrs)	12
- Term Loan B 5Yr Swap	(%)	5.97	- Term Loan B	(Yrs)	5
- Term Loan B Spread	(bps)	140	- Notional amortisation	(Yrs)	25
Refinancings					
- Term Loan A Refi	Yr	2009	- Term Loan B Refi	Yr	2016
- Term Loan A Swap	(%)	5.83	- Term Loan B Swap	(%)	2.52
- Term Loan A Spread	(bps)	457	- Term Loan B Spread	(bps)	213

Sources: RBA, (Simshauser, 2009; Simshauser and Gilmore, 2019)

At \$850/kW, the OCGT plant investment in 2004/05 is \$459 million with total assets of \$487m (including working capital, see Appendix II). The Project Finance comprises two debt tranches, 12-Year Amortising Facility (Term Loan A) and 7-Year Bullet Facility (i.e. interest only, Term Loan B) set in semi-permanent structures with notional terms-to-maturity of 25-years.[18] Using the Dynamic Financial Model and Sizing Parameters (Tab.7) a total debt package of \$303m is credible (i.e. 62% debt to total assets) with *ex-ante* minimum forecast Debt Service Cover Ratios (DSCR) binding at 1.80x. DSCR is the key project financing metric and measures the multiple of forecast surplus cashflows to scheduled debt repayment costs (see Eq.26, Appendix I). The expected running cash yield to equity is ~12.5%, and equilibrium \$300 cap prices under the model equate to ~\$8.2/MWh.

So much for theory. Fig.8 reveals real world (ex-post) performance of the canonical merchant OCGT plant. Results (*Actual Cash Flows*, grey bars) are strikingly different to ex-ante equilibrium expectations (*Expected Cash Flows*, white bars) in Fig.8.

Figure 8: Project Financed Merchant OCGT Plant (2004/05-2019/20)



[18] Note debt re-financings are scheduled to occur in 2009 (Term Load B) and 2016 (Term Loan A). The refinancing of Term Loan B in 2009 occurs during good electricity market conditions but very tough capital markets conditions (i.e. immediate post-GFC). The facility is assumed to be refinanced for a further 5 years, and refinanced again in 2015 (with the headline interest rate having fallen by a factor of 2, i.e. from 10.4% to 5.0%).

Actual Cash Flows produce an average running yield to equity of ~4%, well below the risk-adjusted expected benchmark of 12.5%. Actual Cash Flows in 2004/05 and 2005/06 fall below expectation and then surge above forecast equilibrium in 2006/07-2007/08. There are only two years (i.e. 2008/09 and 2012/13) where Actual Cash Flows resemble Expected Cash Flows. Conversely, the plant experiences seven events of financial distress (red circles, Fig.8).

The horizontal lines in Fig.8 labelled 'Lockup DSCR' and 'Default DSCR' represent project financing covenant thresholds. Whenever the OCGT's DSCR (Actual) line falls below the horizontal 'Lockup' value of 1.35x, project cash flows are 'locked up' and swept by project banks (i.e. distributions to equity cease). Moreover, if the DSCR (Actual) falls below the 'Default' line of 1.10x, the financing package is in breach at which point owners are required to either remedy through an equity injection, or banks foreclose on the project.

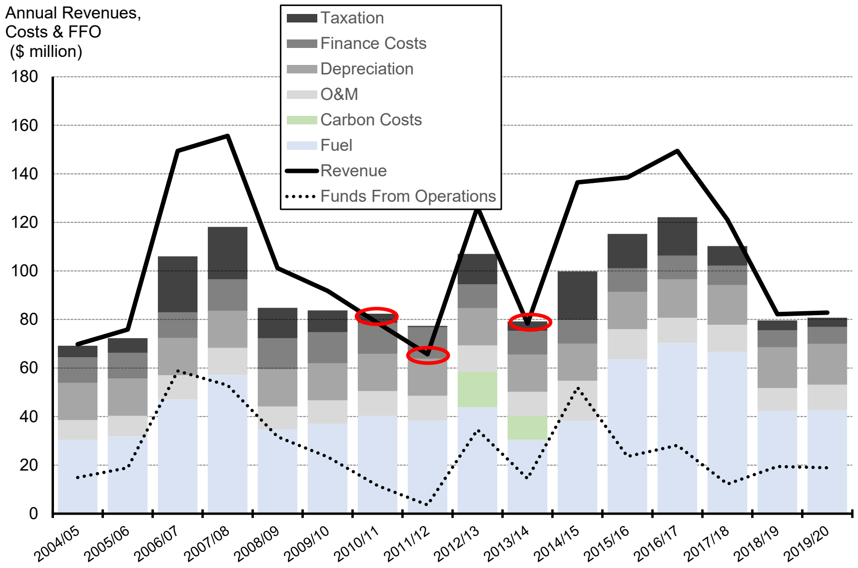
To summarise, the canonical merchant OCGT 'peaking plant' is simply *too volatile* to be 'bankable'. These results are consistent with prior analyses in the NEM's Queensland region by Nelson and Simshauser (2013) and Tian (2016), in the South Australian region by Simshauser (2020a).

4.2 Stand-Alone Merchant OCGT – Corporate (Balance Sheet) Finance

An important driver of the variability of returns in Section 4.1 was the project financing. The OCGT plant was heavily geared with project debt, which comprised 62% of asset funding. Varying the capital structure to corporate financing with gearing levels approximately aligned to investment grade metrics (i.e. ~30% debt to total assets[19]) produces less volatile results.

Results in Fig.9 are based on the 540MW OCGT being financed through a $128 million issue of investment grade ('BBB' rated) corporate bonds (cf. $303m project finance). Plant profitability is illustrated by 'stacking' each of the cost elements (bar series) and contrasting with plant revenues (solid line series). Three episodes of Statutory Losses are highlighted by red circles. To be clear, there is no difference in annual revenues or operating costs of the plant, the only difference is financial leverage. Finally in Fig.9, it is worth noting a critical credit variable, 'Funds From Operations' or 'FFO' (Appendix I, Eq.26) is presented as the dotted line series. FFO is used extensively in the Section 4.5 analysis of credit quality.

Figure 9: Corporate Financing of a Merchant OCGT plant (2004/05-2019/20)



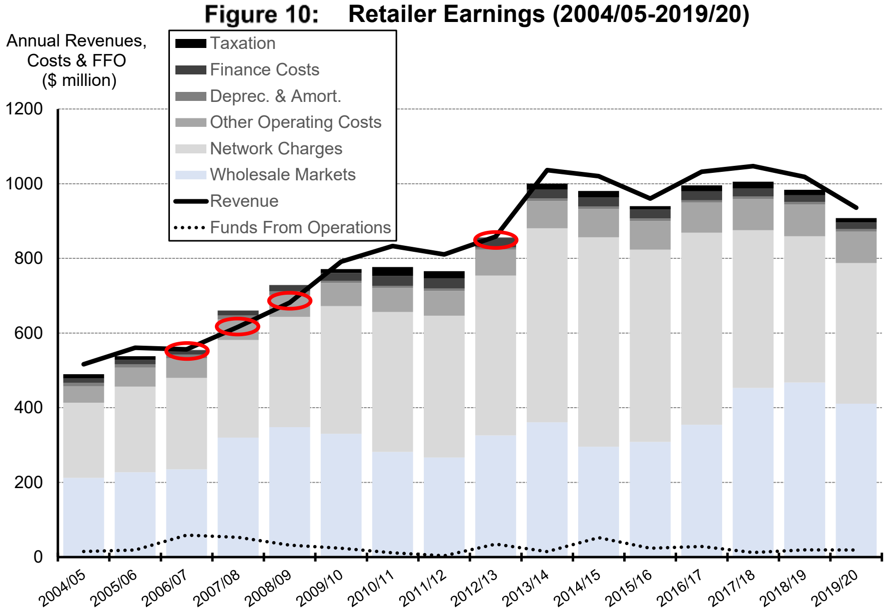
[19] This is the approximate gearing of the NEM's three large (investment grade) integrated energy retailers.

4.3 Stand-alone energy retailer

Section 3 (and Appendices I-III) enable the energy retailer to be simulated from 2004/05-2019/20. Recall the energy retailer faces a regulated tariff cap, and therefore has no ability to raise tariffs. Ex ante hedge commitments[20] are based on a risk neutral strategy comprising a structure of 'swap to average, cap to maximum' with quarterly resolution (Eq.14, Appendix I) and is consistent with approaches adopted by Tian (2016) and Simshauser (2020a). The structure is not necessarily ex-post optimal, but a prudent ex-ante vanilla trading strategy uniformly applied across all variation scenarios to enable direct comparison.[21] Note the Retail Portfolio Model impounds peak demand uncertainty through inclusion of random forecast errors (+/-5%, normally distributed) and own-price demand elasticity estimate of -0.20 in sensitivity cases.

The stand-alone energy retailer is established with initial corporate debt of ~30% against a total asset base of $510 million (i.e. acquisition metrics from Tab.3 plus opening working capital of $244m per Appendix I-II). Stacked costs (bar series) and revenues (line series) are presented in Fig.10. The energy retailer experiences four episodes of negative profits (red circles) while FFO (dotted line series) remains positive, albeit just, over the 16-year trading window.

Figure 10: Retailer Earnings (2004/05-2019/20)



4.4 Vertical Integration: energy retailer + 540MW OCGT plant

At this point, the energy retailer and OCGT are merged. This produces series of important synergies vis-à-vis transaction costs:

a) Total OCGT capacity is 'internalised' by the energy retailer as a physical hedge rather than relying exclusively on 'on-market' financial derivative transactions (i.e. swaps and caps). The energy retailer reduces $300 cap and peak swap purchases on a MW-for-MW basis for any given plant capacity. Recall from Tab.2 the (ex-ante) accumulated $300 cap portfolio traded at a 37% premium to (ex-post) settlement prices, and peak swaps traded at an ~11% premium. Consequently, a merger eliminates contract these premia on a MW-for-MW basis.

[20] Recall that the accumulated hedge portfolio occurs over a three-year window (Quarterly quantity resolution, settled against 30-minute spot prices).
[21] To the extent that any profit improvement (or consequential loss) could be initiated by active trader intervention, such gains/losses would also apply to all business combinations in a largely uniform manner.

b) For reasons which become apparent via Figs.13-15, debt costs of the merged entity reduce due to materially enhanced credit metrics arising from combining two countercyclical businesses (i.e. energy retailer's Net Profit After Tax (NPAT) and FFO results are negatively correlated to the OCGT plant's NPAT and FFO results, -0.48 and -0.56 respectively as Figs.12-13 subsequently reveal).

Recall as stand-alone businesses, multiple statutory loss results were observed by either the OCGT or energy retailer in Years 3, 4, 5, 7, 8, 9 and 10. But as Fig.11 reveals, a merger of the energy retailer and OCGT has the effect of eliminating all loss events. This is a material finding, and has been driven by three integration dynamics:

1. OCGT losses occur in years 7, 8 and 10. Energy retailer losses occur in years 3, 4, 5 and 9. There is no year where both businesses incur a loss. Consequently, merging two countercyclical businesses provides portfolio diversity benefits from a profitability perspective. That is, when one business is in duress, the other performs well, and vice versa.

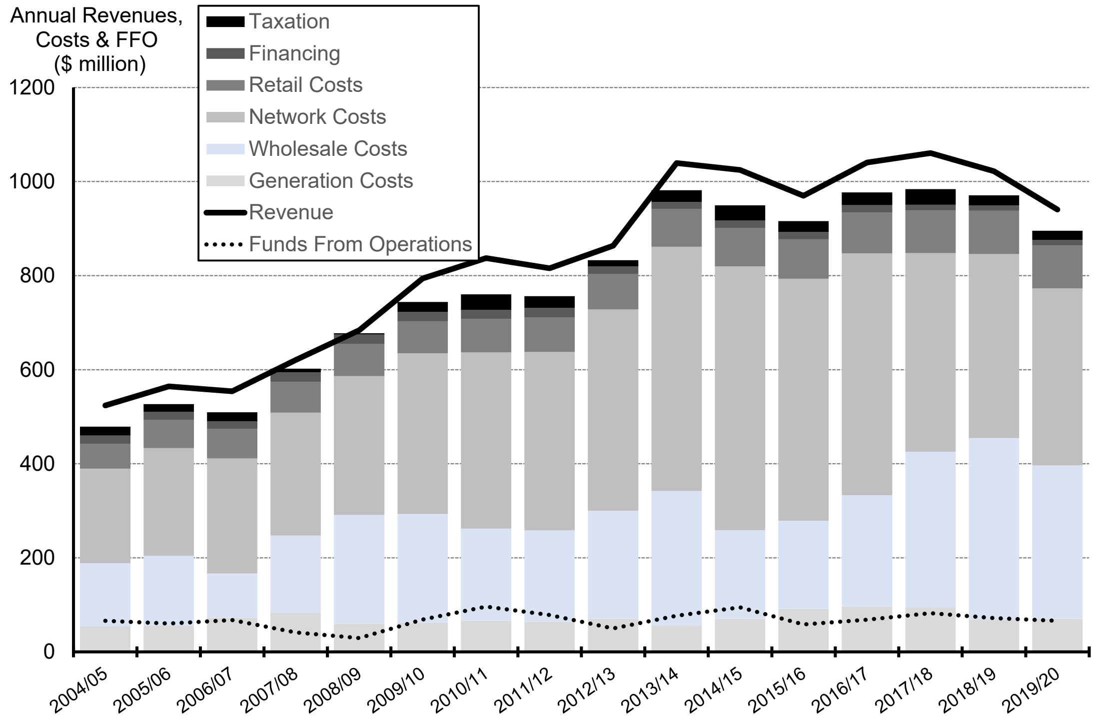
2. Arising from transaction cost synergies identified in a). above, the underlying performance of the energy retailer is enhanced through eliminating contract premiums, and by exhausting the full capacity and output of the OCGT against retail load which means price protection commences from the plants marginal running cost, well below \$300/MWh[22].

3. Arising from reduced transaction costs identified in b). above, combining countercyclical businesses also enhances credit metrics, which ceteris paribus, will produce lower debt transaction costs.

Earnings for the vertical entity are illustrated in Fig.11. Note all years exhibit positive earnings.

[22] There are two transactional gains here. First, the stand-alone generator is 70% hedged in a manner consistent with the findings of (Anderson, Hu and Winchester, 2007) but an energy retailer can exhaust the full capacity because unavailability risk only matters when prices spike *and* load is elevated, which has a lower probability than outage risk. Second, cap contracts only return a CfD for prices over \$300/MWh whereas ownership of the OCGT returns the equivalent of a CfD for prices over the OCGTs unit fuel cost which is significantly lower than \$300 (i.e. the insurance deductible has been lowered through OCGT ownership).

Figure 11: Energy retailer + OCGT Earnings – Vertical Integration (2004/05-2019/20)



Among the most important results in this article are Fig.12, which compares the stability and strength of NPAT results by business over the 16-year analysis via distribution (box) plots. In Fig.12, the shaded box areas capture the 25th-75th percentile NPAT distribution for each business, and 'dash' markers inside the box plots highlight median NPAT results. Diamond markers on the box-tails represent the 5th and 95th percentile result, and the box-tail ends represent maximum and minimum NPAT. The NPAT results in Fig.12 illustrate (in order) are:

1. Stand-alone project financed OCGT (Section 4.1)

2. Stand-alone corporate financed OCGT (Section 4.2)

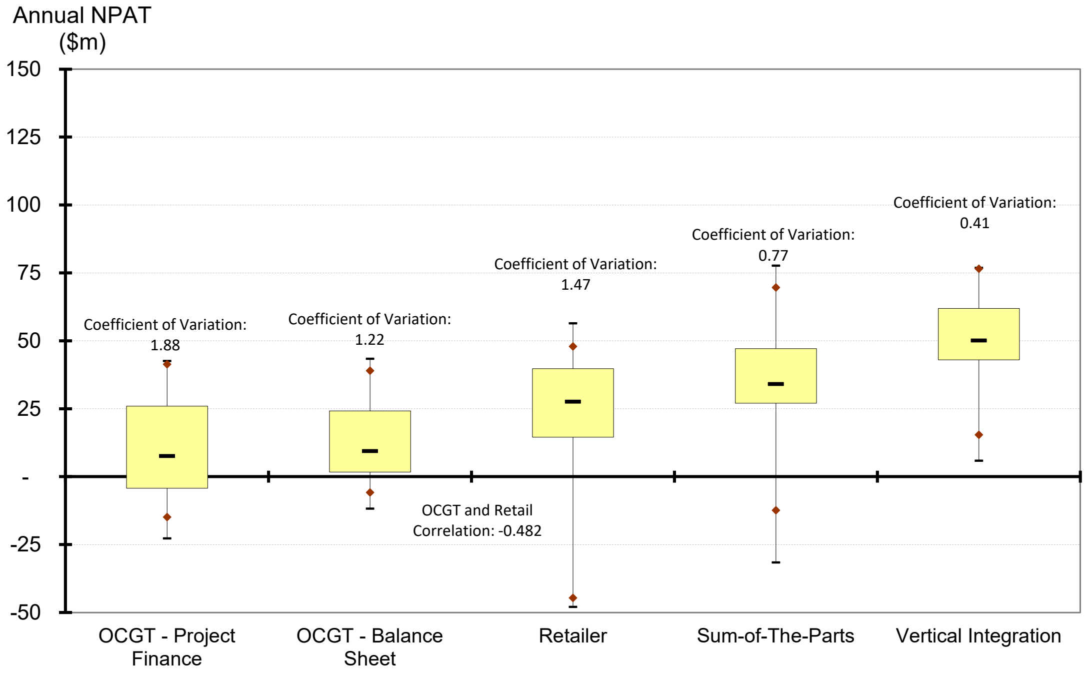
3. Stand-alone energy retailer (Section 4.3)

4. A "Sum-of-The-Parts" (SoTP) result – the simple addition of the stand-alone OCGT (Section 4.2) and stand-alone energy retailer (Section 4.3) as if held in separate unit trusts. This highlights benefits of owning countercyclical businesses, but excludes optimised transaction cost synergies outlined in a) and b) above. These latter benefits can only be captured through vertical integration.

5. Vertical integration of the energy retailer and OCGT (Section 4.4). By comparison to SoTP, vertical integration incorporates transaction cost synergies from internalising on-market transactions, and adjusted debt costs reflecting stronger credit metrics (per Figs.13-14).

There are two reasons for distinguishing between SoTP and vertical integration. First, SoTP helps isolate benefits of merging countercyclical businesses. Second, vertical integration helps isolate transaction cost synergies – thereby dispelling arguments in finance theory that shareholders can achieve their own portfolio diversification through shareholdings (rather than at the firm level). Fig.12 SoTP demonstrates portfolio diversification at the shareholder level is not plausible for generation and energy retailing – some gains are only achieved via vertical integration.

Figure 12: NPAT Distribution 2004/05 – 2018/19



Note in Fig.12 the most volatile business is 'OCGT - Project Finance' with 1.88 coefficient of variation. The next most volatile business is the 'Retailer' at 1.47. Following this is 'OCGT – Balance Sheet' (i.e. corporate finance) at 1.22, with the simple 'Sum-of-The-Parts' next at 0.77. Note the negative correlation between OCGT and Retail NPAT is -0.482. Finally, note 'Vertical Integration' has by far the lowest variation in earnings (0.41) and is also the *only* business that avoids posting Net Losses.

4.5 The role of credit and credit ratings in energy-only markets

Recall from Section 1 the central question regarding resource adequacy in energy-only markets with a high VoLL is whether investment commitment occurs in a timely basis, or in response to a crisis. A necessary pre-condition for the former is the ability of firms to make timely investment commitments, and this requires firms to raise requisite debt and equity capital under uncertainty, and this invariably hinges on the presence of investment grade credit for reasons set out in Section 2 (see also Simshauser, 2010).[23]

It is beyond the scope of this article to undertake a comprehensive review of credit quality, and for those interested Tian (2016) provides a thorough analysis. For the purposes of this article two credit metrics (Tab.8) provide the quintessential foundations for merchant utilities. [24] In an applied sense, the Tab.8 metrics are frequently the *binding metrics* (see Eq.23-26, Appendix I).

[23] The intuition here is as follows. The capital intensity of generation plant will generally preclude an all-equity financing by a sub investment-grade firm. Further, a sub investment-grade firm is unlikely to have the capacity to originate sufficient (and cost efficient) corporate debt. A project financing is of course entirely feasible for such a firm but only if a counterparty with an investment-grade credit rating writes the PPA (this being the typical pre-condition of project debt). For further details see Simshauser (2010).
[24] The array of quantitative and qualitative measures is indeed vast (See (Standard & Poor's, 2014; Moody's, 2017a, 2017b) for further details). The most logical manner to analyse the current set of credit results is to assume these business combinations are regional subsidiaries of a larger multi-regional energy utility, and whether the current businesses under consideration are likely to add or subtract to overall credit quality.

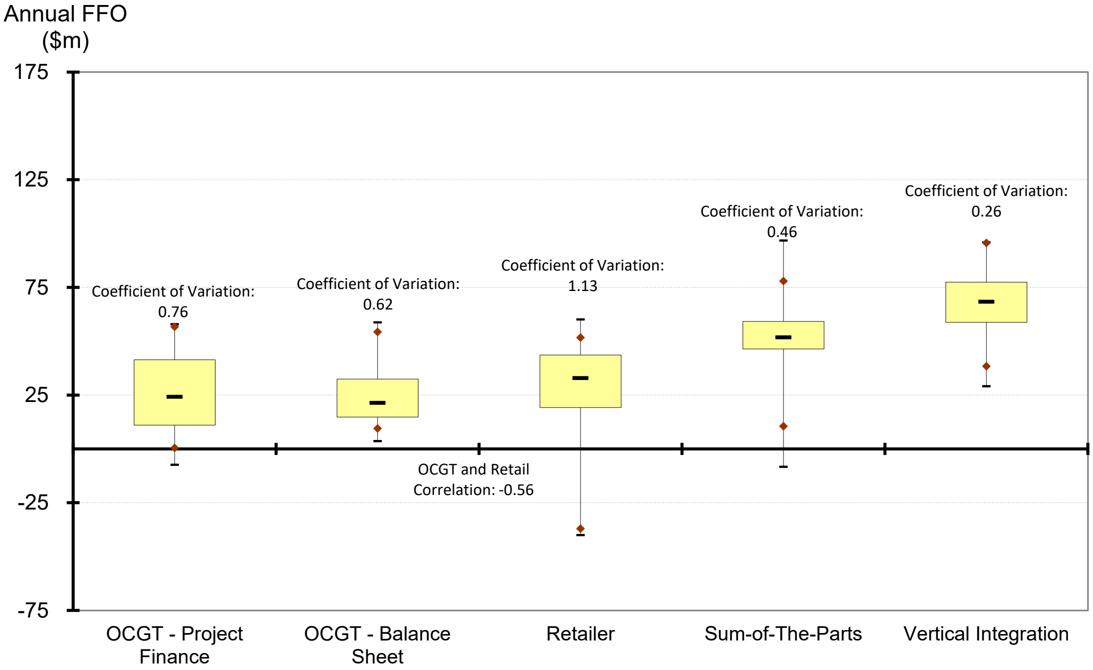
Table 8: Credit Ratings Metrics

Credit Metric	Investment Grade (BBB)	Sub-Investment Grade
FFO / Interest	≥ 4.0x - 8.0x	< 4.0x
FFO / Debt	≥ 0.19 - 0.35	< 0.20x

(Standard & Poor's, 2014; Moody's, 2017a, 2017b)

Both metrics in Tab.8 rely on FFO which as noted earlier is a central variable in credit analysis. Fig.13 presents FFO box charts for the various businesses. Once again, results point towards a clear trend, vertical integration as the most robust configuration.

Figure 13: FFO Distribution 2004/05 – 2018/19



The 16-year performance of the Tab.8 credit metrics are presented in Figures 14-15 for the stand-alone OCGT, the energy retailer, and the integrated entity. Grey-shaded areas represent 'BBB' credit quality. Credit quality rises monotonically, meaning results *above* the grey area are drifting into BBB+, and results below are drifting towards BBB- (or lower, i.e. into junk).

Figure 14: FFO/Interest (2004/05-2019/20)

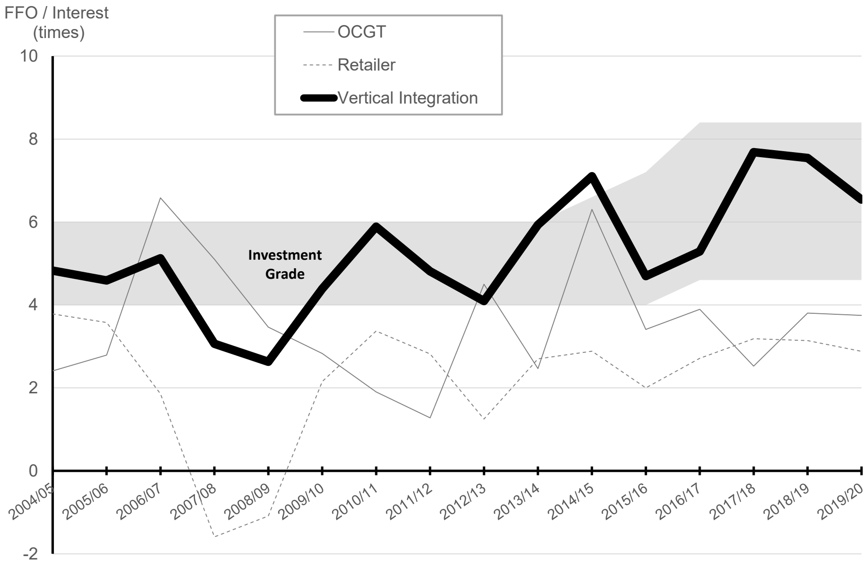
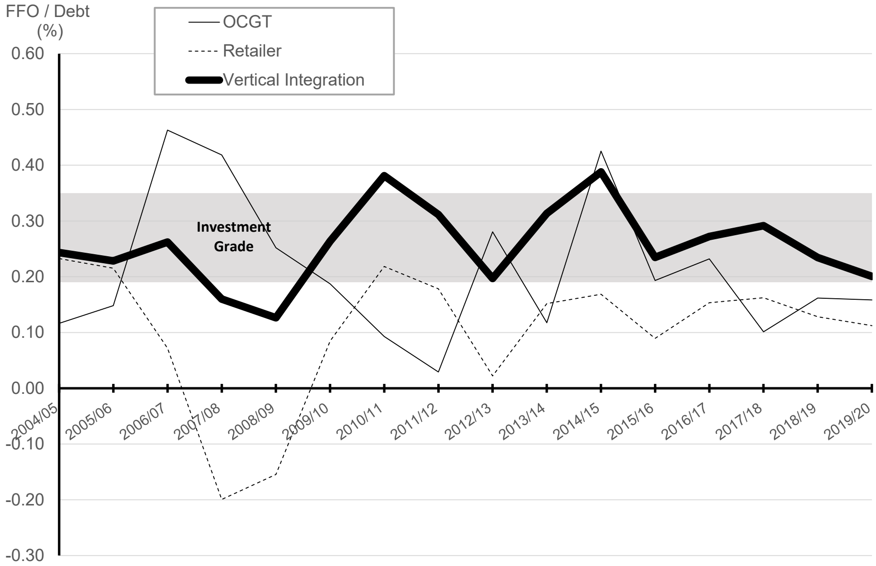


Figure 15: FFO/Debt (2004/05-2018/19)



Results suggest neither the OCGT nor energy retailer present anything like investment-grade credit quality. Conversely, vertical integration produces consistent investment-grade metrics. A transient excursion occurs during 2007/08-2008/09[25] when Queensland wholesale prices surged. Retail tariff cap regulatory lag meant energy retailers experienced difficult trading conditions. A capricious regulated tariff cap determination also emerged in 2012/13, with similar impacts. These volatile wholesale market conditions were ideal for OCGTs. Consequently, integration improves combined profitability, credit quality and helps mitigate regulatory risks.

4.6 Analysis of transaction costs and Economies of Vertical Integration

Quantifying the transaction cost synergies from vertical integration (i.e. sub-additive costs or *economies of vertical integration, EVI*) can be derived through Eq.1 based on Baumol, Panzer and Willig (1982). Positive values imply economies of integration and negative values imply diseconomies. In Eq.1 total costs C for each year n are summed for the OCGT generator G, energy retailer R and vertically integrated merged entity, VI.

$$\sum_{n=1}^{|Y|} EVI_{VI}^{n} = \left(\sum_{n=1}^{|Y|} \frac{C_{(G,0)}^{n} + C_{(0,R)}^{n} - C_{(VI)}^{n}}{C_{(VI)}^{n}} \right) \qquad (1)$$

Recall from Section 4.4 the source of gains from vertical integration come from two primary sources:

a. Internalising on-market transactions, which reduces forward contract premia[26]; and

b. enhanced credit metrics, which produces lower debt financing costs.

Results from Eq.1 appear in Tab.9. Internalising certain on-market derivatives produces transaction cost synergies of 13% or \$1.98bn (i.e. \$14,100m - \$12,227m) over the 16-year trading window. The form of Eq.1 has also been applied to Net

[25] The fact that the Vertical firm experiences a transient excursion outside BBB metrics during 2007-2009 does not mean an automatic downgrade to BBB- (nb still investment grade), although 'negative watch' would surely arise. Ratings Agencies tend to 'look through' transient deterioration in metrics and in my view, the extraordinary trading conditions in 2008/09 would have been accounted for accordingly. However, the fact that transient episodes are entirely possible also justifies targeting BBB rather than BBB-.

[26] And in addition, making maximum use of OCGT capacity, and benefiting from a lower strike price (i.e. OCGT fuel costs are lower than the \$300 cap strike price, thus providing a lower deductible).

Profits, Economic Returns, FFO and variability of returns (i.e. by replacing the variable C with these other variables). Regardless of the dimension measured, economies of vertical integration are material across the 16-year analysis period.

Table 9: Analysis of transaction costs and Economies of Vertical Integration

Period 2004/05-2019/20	OCGT	Retailer	SoTP	VI	EVI
Transaction Costs					
Total Costs ($m)	1,324	12,776	14,100	12,227	13%
Cumulative Earnings					
Net Profit After Tax ($m)	215	324	539	790	47%
Economic Returns (%)	7.4%	7.2%	7.3%	9.4%	30%
Credit Quality					
Funds From Operations ($m)	419	402	821	1,073	31%
Coeff. of Variation (Fig.12)	0.62	1.09	0.43	0.25	41%

However, economies of vertical integration are sensitive to market conditions and the level of integration. Sensitivities are examined in Section 5.

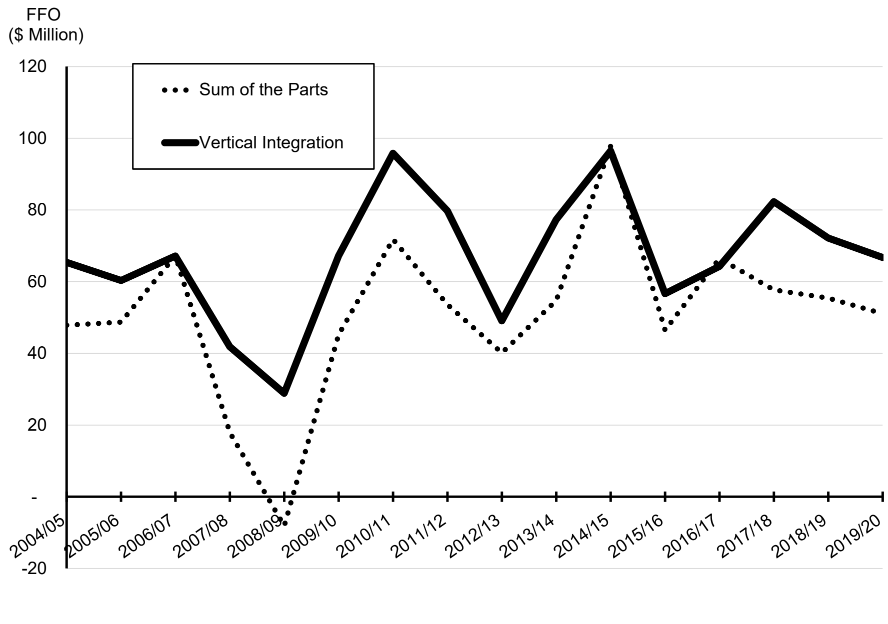
5. Sensitivity Analysis

Over the 16-year analysis period, energy retailer peak demand ranges from 750-1150MW (Fig.4-5) with average demand of ~500MW. Accordingly, a 540MW OCGT primarily covered the energy retailer's uncertain peak period customer demand. Section 4 revealed cost subadditivity but did not consider conditions that may produce diseconomies of integration, nor whether economies are sensitive to the level of vertical integration.

5.1 Market conditions that produce diseconomies of integration

Tab.9 presented economies of vertical integration (i.e. 13% transaction cost synergies) but this was the cumulative result. The year-on-year analysis in Fig.16 reveals small diseconomies prevailed under a certain set of electricity market conditions, via a direct comparison of SoTP and Vertical Integration FFO results.

Figure 16: Dynamic Analysis of Economies of Vertical Integration (FFO)



The source of diseconomies can be directly traced to *ex-post* performance of $300 caps. Whenever the broader market was *'caught out'* by the extent of price spike events and $300 cap payouts exceed ex-ante contract premiums received, diseconomies prevailed (i.e. negative premia events). Data in Tab.1 and Fig.16 reveal this occurred 2006/07, 2014/15 and 2016/17.

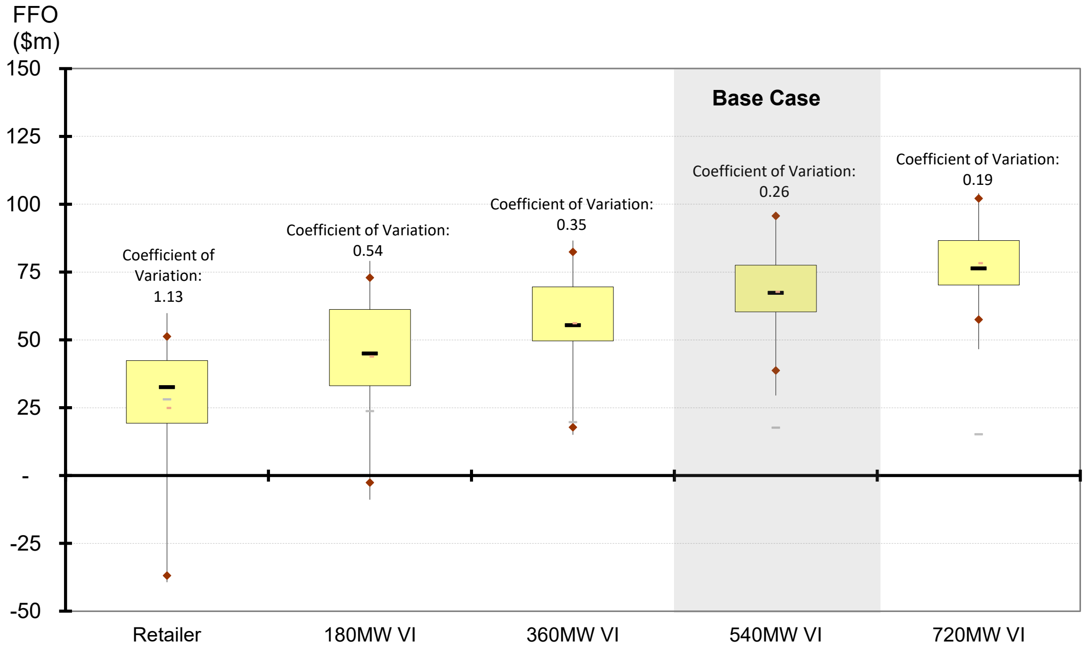
5.2 Vertical integration and the size of OCGT plant

Simulation modelling focused on a 540MW OCGT plant because it adequately covered the energy retailer's uncertain peak demand. Thus far, no attempt to optimise OCGT sizing has been undertaken. To be clear, energy retailer peak demand evolved over the 16-year window and hence optimal sizing in Year 1 is unlikely to meet optimal sizing requirements by Year 16. Further, gas turbine unit sizes are lumpy, not perfectly divisible. However, stress-testing plant size is plausible. Four plant sizes were analysed:

1. 180MW;
2. 360MW;
3. 540MW (base case); and
4. 720MW.

Fig.17 illustrates the FFO box plot for the four plant sizes and contrasts these results with the stand-alone energy retailer.

Figure 17: Energy retailer vs Integrated OCGT (180MW-720MW)



As plant size increases, FFO increases and the coefficient of variation decreases. By this measure, 720MW is optimal. However, FFO does not adjust for capital deployed. Tab.10 repeats the Tab.9 transaction cost analysis for all plant sizes. If 'Economic Returns' formed the guiding metric, 180MW plant (9.9%) is optimal. If improvement in 'Net Profit After Tax' formed the guiding metric, 540MW (48%) is optimal.

Table 10: Analysis of transaction costs- Economies of Vertical Integration by plant size

Period 2004/05-2018/19	EVI 180MW	EVI 360MW	EVI 540MW	EVI 720MW
Transaction Costs				
Total Costs	6%	10%	13%	15%
Cumulative Earnings				
Net Profit After Tax	47%	47%	48%	45%
Economic Returns*	9.9%	9.7%	9.4%	9.2%
Credit Quality				
Funds From Operations	36%	33%	31%	28%
Coeff of Variation (Fig.17)	28%	37%	42%	49%
*Absolute result. All other results are the % improvement				

The metrics in Tab.10 prove conflicting. Yet recall an important driver of resource adequacy in energy-only markets is the ability of firms to issue debt and raise equity capital under uncertainty, which is best catalysed through investment grade credit. Fig.18-19 repeat the credit parameters outlined in Tab.8 for the four plant sizes. Charts reveal credit measures are *amplified* as plant size reduces. Consequently, while smaller plant sizes (i.e. 180-360MW) deliver better Economic Returns, they are unable to adequately mitigate risks to credit quality arising from regulatory lag during 2007-2009. This tends to suggest larger plant sizes are important.

Figure 18: Funds From Operations / Interest

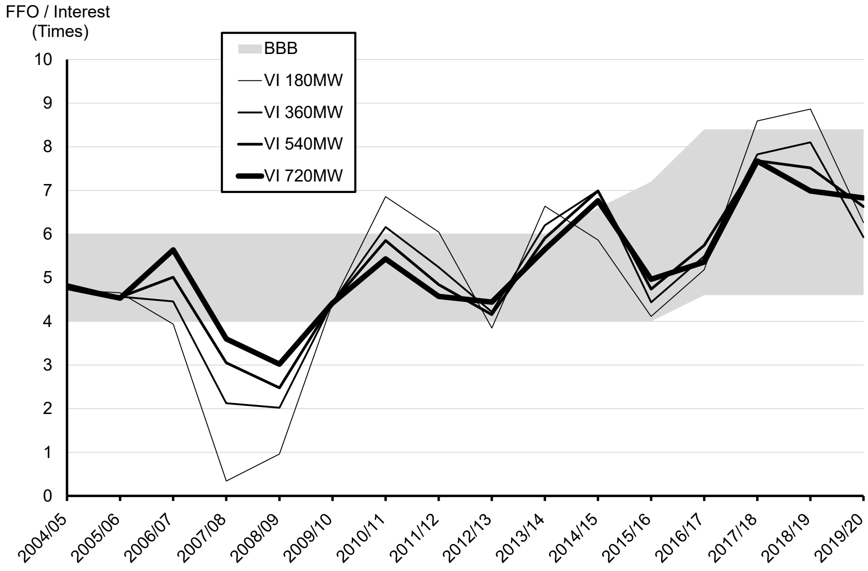
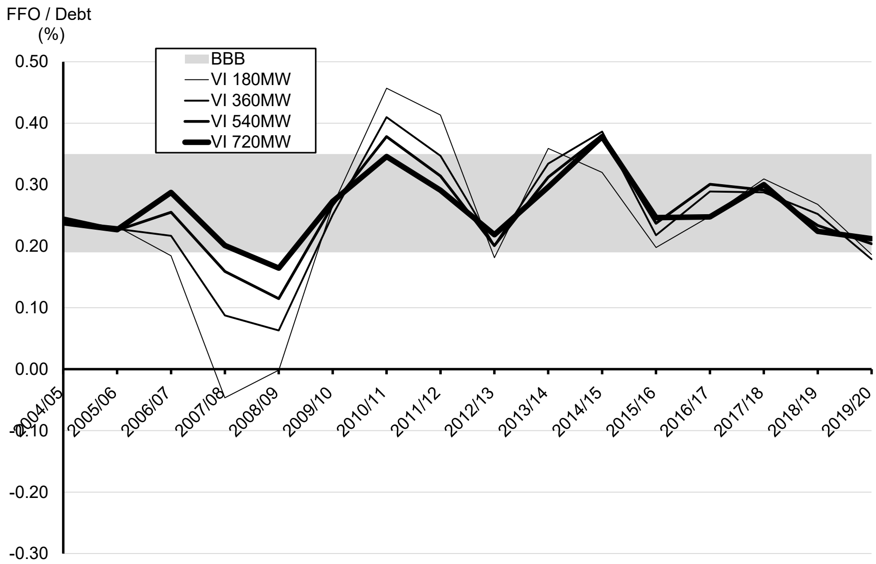


Figure 19: Funds From Operations / Debt



6. Policy implications

The need for dispatchable capacity in a market with rising levels of intermittent renewables and coal plant exit is axiomatic. Finon's (2008) observation that the 'canonical merchant model' has failed, still holds according to Section 4.1 results. Stand-alone peaking plant has long been considered 'unbankable'. Seamless entry was identified as problematic at least as far back as Doorman (2000).

From an applied perspective, >75% of NEM gas turbine plant commitments were delivered by energy retailers. Vertical integration has historically been treated with suspicion by many NEM policymakers due to concerns over potential for market power abuse, and declining forward market liquidity (and consequential risks of independent energy retailer foreclosure).

Policymaker intuition was partially correct. Australia's 'Big 3' energy retailers have made significant vertical commitments. The problem is their horizontal scale (72% market share in 2017), not vertical integration. Independent portfolio generators dominate the NEM's list of notable market power events (see Simshauser, 2021) and although vertical retailers no doubt internalise significant levels of forward market activity, they remain net-long or net-short. NEM liquidity metrics of 300+% of physical reveal no evidence of forward market damage via vertical activity (see Simshauser, 2021).

In this article, a non-dominant energy retailer and OCGT generator was selected to eliminate the possibility of Bain's (1956) market power motive for vertical integration. Modelling results demonstrated strong motives exist for vertical mergers. Key motives were condensed down to two elements unable to be extracted through diversification at the individual shareholder level:

a) Transaction cost synergies. Shifting an energy retailer's on-market transactions for uncertain peak loads to an in-house OCGT had the effect of eliminating forward market premia; and

b) Financing gains from enhanced credit quality. Combining two countercyclical businesses delivered materially enhanced credit metrics. Absent vertical integration, an energy retailer cannot sustain investment-grade credit metrics.

Two important issues further underpin transaction cost motives. The first is that through integration, the success of an energy retailer's business collapses down to management of on-market base load exposures. Recall from Table 2 base load swaps impounded no visible forward contract premia.

Second, absent an investment grade credit rating, an energy retailer may find it difficult to commit to new peaking plant on a timely basis rather than in response to a crisis. Credit quality is an important precondition to raising debt capital. And an important precondition to OCGT plant commitment is the ability to raise debt capital.

These characteristics matter for consumer welfare. *If* firms are capable of raising capital and committing to plant on a timely basis, consumers are less likely to face disruptive cyclical price events. Further, cost structures of vertical firms are inherently lower than SoTP – Tab.10 suggesting 6-15% lower. A market characterised by vertical firms should, all else equal, face lower resource costs, and a competitive market should produce lower clearing prices, thus being welfare enhancing.

7. Concluding remarks

In this article, an OCGT plant and energy retailer located in the Queensland region of Australia's NEM were simulated using granular historic market data over a 16-year period, 2004/05-2019/20. OCGT plant proved largely unviable as a merchant project financing. Quantitative results revealed the stand-alone energy retailer was unable to maintain investment-grade credit metrics. Timely plant entry is contingent upon the ability of firms to raise capital, which invariably circulates back to the presence of investment-grade credit one way or another.

Markets inevitably navigate uncertainty. As Williamson (1971) noted long ago, when firms are confronted with transaction costs such as asset specificity, technical dependency, bounded rationality, incomplete markets, regulatory risk and uncertainty, vertical integration becomes a predictable outcome. Quantitative results showed the vertical merger of an energy retailer and OCGT plant produced transaction cost synergies of ~13% and credit quality could be maintained at levels consistent with investment-grade metrics. These parameters help explain why energy retailers in Australia's NEM are responsible for >75% of the NEM's gas turbine commitments.

Despite rapid uptake of solar PV, falling per-household consumption and changing pattern of relative prices, the motive for energy retailers to maintain resource adequacy does not appear to have diminished. Relative inaction by energy retailers vis-à-vis peaking plant commitments during the supercycle must therefore be explained by other variables, viz. political interference in the market (Wood, Dundas and Percival, 2019a) or preferences for new technologies (i.e. battery storage).

Vertical integration is an organisational form of last resort (Williamson, 2008). As Stuckey and White (1993) explain, vertical M&As are expensive, risky and particularly hard to unwind. Firms ultimately prefer on-market transactions. However, when on-market transaction costs exceed the costs of bringing functions in-house, vertical activity will prevail. It is noteworthy that all significant merchant utilities in Australia's NEM are integrated, something Kwoka (2002) observed in the US almost two decades ago. Model results and practical evidence suggests 'cost forces' and 'sequential adaptation' vis-à-vis transaction cost synergies are important.

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Models

In order to analyse the energy retailer, OCGT generator and a vertical merger, three sequential models are necessary, viz. i). a Unit Commitment Model for 30-minute OCGT plant dispatch, ii) a Retail Portfolio Model for 30-minute load hedging and settlement, and iii). Dynamic Financial Model (annual resolution) capable of producing static profit and dynamic valuation metrics.

The Unit Commitment and Retail Portfolio Models were built with operational timeframes in mind, viz. 30-minute resolution over 'n' years with results rolled-up into Quarterly outputs.

Unit Commitment Model

The Unit Commitment Model simulates plant dispatch for each 30-minute trading interval over the 2004/05-2019/20 period. The Model objective function is to maximise spark spread options inherent in spot electricity and gas prices, subject to various plant constraints and non-convexities. Essential model inputs include OCGT technical and financial data (Table 3), and the 30-minute spot electricity prices and daily gas prices. Model structure as follows:

Let H be the ordered set of Half-Hour trading intervals in each year n.

$$t \in \{1..|H|\} \wedge h_t \in H, \tag{2}$$

Let $\bar{G}$ be the ordered set of gas turbine units at maximum continuous rating, $\bar{g}_j$.

$$j \in \{1..|\bar{G}|\} \wedge \bar{g}_j \in \bar{G}, \tag{3}$$

Marginal Running Costs include Fuel $F(g_j^t)$ and Variable Operations & Maintenance costs (VOM_j^t). $F(g_j^t)$ is non-convex because of start-up quantity a_j with marginal fuel consumed at the plant's heat rate h_j. Each coefficient is strictly non-negative. p_F^t is the price of Fuel. Once operational, MRC_j^t reduces because Fuel consumed during the start-up sequence (a_j) is sunk.

$$MRC_j^t = F(g_j^t) \cdot p_F^t + g_j^t \cdot VOM_j^t \left| F(g_j^t) = if \begin{cases} g_j^{t-1} = 0, a_j + h_j \cdot g_j^t \\ g_j^{t-1} > 0, h_j \cdot g_j^t, \end{cases} \right. \tag{4}$$

Following unit commitment, quantity generated g_j^t is bounded by maximum rated capacity $\bar{g}_j$ and minimum stable load $\underline{g}_j$.

$$\underline{g}_J < g_j^t < \bar{g}_j \; \forall \; g_j^t > 0, \tag{5}$$

Plant is subject to annual planned outages of one week $(o_{j,u}^t)$, periodic Major Inspections of one month, and forced outages of 6% $(\alpha_{j,u}^t)$ per annum. Planned outages are pre-scheduled in mild seasons. Forced outages (including failed starts) are random, occurring throughout the year. Available capacity is therefore stochastic and modelled at the station level for each trading interval:

$$\sum_{j=1}^{|\bar{G}|} \overline{g}_j^t \mid if \begin{cases} rand[0..1] < \alpha_{j,u}^t \wedge t \neq o_{j,u}^t, \; \overline{g}_j^t \\ rand[0..1] \geq \alpha_{j,u}^t \vee t = \; o_{j,u}^t, 0, \end{cases} \tag{6}$$

Gas turbines are subject to a start-up sequence(γ_j) which means maximum output in the first trading interval following unit commitment is not feasible:

$$if\ p_e^t > MRC_j^t \wedge g_j^{t-1} \begin{cases} = 0, (\gamma_j \cdot \overline{g}^t) \\ \neq 0, \overline{g}^t, \end{cases} \tag{7}$$

Gas turbines have practical minimum economic run-times. Unit commitment is subject to expected electricity prices p_e^t over a look-ahead period (θ) set to four hours to ensure units are not started for brief periods of marginal value.[27] Conversely, if already operational and marginal value is expected, units remain in service:

$$g_j^t = if \begin{cases} \sum_{\mathrm{t}}^{t+\theta} \frac{p_e^t}{\theta} \geq \mathrm{MRC}_j^t, \overline{g}^t \\ g^{t-1} > 0 \wedge p_e^t \geq \mathrm{MRC}_j^t, \overline{g}^t \\ Otherwise\ 0, \end{cases} \tag{8}$$

In the present exercise, key financial and operational outputs for each trading interval *t* in each year *n* are extracted and rolled-up into an ordered set of quarterly and annual results $(n = 15)$.

Generation revenue for year n (R_G^n) is calculated as the sum of spot revenues, Cap sales less Contract-for-Difference payments on Caps:

$$R_G^n = \sum_{j=1}^{|G|} \sum_{t=1}^{|H|} \left(g_j^t \cdot p_e^t \cdot T\right) + \sum_{t=1}^{|H|} [(v_c^n \cdot p_c^n \cdot T) - (max(0, p_e^t - p_s) \cdot v_c^n \cdot T)] \tag{9}$$

where

v_c^n	= volume of Caps (MW)
p_c^n	= price of Caps (\$/MWh)
T	= duration of each time period *t* (in hours)
p_s	= strike price of Cap (\$/MWh)

Generation plant Marginal Running Costs for year n (MRC_G^n) is calculated as the sum of start-up fuel, fuel used during operations and VOM.

$$MRC_G^n = \sum_{j=1}^{|G|} \sum_{t=1}^{|H|} \left[\left(s_j^t \cdot a_j + h_j \cdot g_j^t\right) \cdot p_F^t + \left(VOM_j^t \cdot g_j^t\right)\right] \Big| if\ s_j^t = \begin{cases} 1, g_j^t > 0\ and\ g_j^{t-1} = 0 \\ 0, \end{cases}, \tag{10}$$

where

s_j^t = unit starts in each dispatch interval for each unit, *j*

Retail Portfolio Model

The Retail Portfolio Model produces the energy retailer's wholesale energy Costs for each 30-minute trading interval over the period 2004/05-2019/20. Model structure is as follows:

Let Ψ be the ordered set of customer segments in the portfolio.

$$k \in 1..|\Psi| \wedge \psi_k \in \Psi \wedge \forall \mathrm{k}, \mathrm{m} | \mathrm{k} \neq \mathrm{m}, \mathrm{k} \neq \mathrm{u}, \mathrm{m} \neq \mathrm{u}: \psi_k \cap \psi_m = \{\}, \tag{11}$$

Let Ω be the ordered set of customers within each customer segment:

[27] The consequence of Eq.(8) 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.(6) unit commitment will capture major price spikes reflecting an assumption of high quality short-term price forecasting.

$$w \in \{1 \dots |\Omega|\} \wedge \omega_w \in \Omega, \tag{12}$$

For each year n, energy retailer's revenues R_R^n are calculated as follows:

$$R_R^n = \left[\sum_{k=1}^{|\Psi|} \sum_{w=1}^{\Omega} \left(\Gamma_f^{k,n} \cdot d^n\right)\right] + \left[\sum_{k=1}^{|\Psi|} \sum_{t=1}^{|H|} \left(\Gamma_r^{k,n} \cdot l_t^k \cdot \left(1 - \delta^{k,n}\right)\right)\right], \tag{13}$$

Where

$\Gamma_f^{k,n}$	= Tariff daily fixed charge for customer segment k
d^n	= the number of billing days
$\Gamma_r^{k,n}$	= Tariff variable rate for customer segment k
l_t^k	= customer segment k's load in trading interval t
$\delta^{k,n}$	= weighted average market contract discounts

Wholesale energy costs (W^n) comprise spot market purchases and difference payments on forward contracts (base swaps, peak swaps and caps). Forward contracts are layered at quarterly resolution using a risk averse trading strategy of 'swap to average, cap to maximum' demand noting that maximum demand incorporates a randomized forecast error of +/-5% to account for portfolio uncertainty which ordinarily confronts Retailers. Costs are therefore calculated as follows:

$$W^n = \sum_{t=1}^{H}\left[p_e^t \cdot \sum_{k=1}^{\Psi} l_\psi^t \cdot T\right] + \sum_{t=1}^{H}[(p_e^t - p_b^t) \cdot v_b^t \cdot T] + \sum_{t=1}^{H}\left[\left(p_e^t - p_p^t\right) \cdot v_p^n \cdot T\right] + \sum_{t=1}^{H}[-p_c^n \cdot v_c^n + (p_e^t - p_s) \cdot v_c^n \cdot T], \tag{14}$$

where

v_l^t	= aggregate customer load (MW) in trading interval (t)
v_b^t, v_p^t	= volume of base swaps and peak swaps (MW)
p_b^t, p_p^t	= price of base swaps and peak swaps ($/MWh)

Dynamic Financial Model

The Dynamic Financial Model takes model results from the Unit Commitment Model and the Retail Portfolio Model (at quarterly resolution) and after combining these with a series of input assumptions (see Appendix II), a comprehensive set of business valuation metrics and financial statements (Profit & Loss, Balance Sheet, Cash Flow, Taxation Schedule, Debt Facility module for corporate debt and for Project Finance) are generated. The model is structured as follows:

Let Y be the ordered set of Years.

$$n \in \{1..|Y|\} \wedge y_n \in Y, \tag{15}$$

Let $\bar{B}$ be the ordered set of business combinations.

$$\beta \in \{1..|\bar{B}|\} \wedge \bar{b}_\beta \in \bar{B}, \wedge \beta = \{G, R, VI\} | G \cap R = \{\} \wedge VI = G \cup R, \tag{16}$$

- **Generation Profit & Loss**

$$\Pi_G^n = (R_G^n - MRC_G^n - FOM_G^n - d_G^n - I_G^n - \tau_G^n) \wedge EBITDA_G^n = (R_G^n - MRC_G^n - FOM_G^n), \tag{17}$$

where

Π_G^n	= Profit function or Net Profit After Tax (NPAT)
FOM_G^n	= Fixed Operations & Maintenance
d_G^n	= Depreciation & Amortisation
I_G^n	= Financing costs
τ_G^n	= Taxation

$EBITDA_G^n$ = Earnings before Interest, Tax, Depreciation & Amortisation

- **Retail Profit & Loss**

$$\Pi_R^n = (R_R^n - W^n - OE^n - ROC^n - d_R^n - I_R^n - \tau_R^n) \wedge EBITDA_R^n = (R_R^n - W^n - OE^n - N^n - ROC^n), \quad (18)$$

Where

OE^n = Other Energy Costs relating to wholesale markets[28]

N^n = Network charges

ROC^n = Retail Operating Costs[29]

If profits are made, dividend payout ratio (DPR_β) is:

$$Divi_\beta = if\,\Pi_\beta^n \begin{cases} > 0, \Pi_\beta^n \cdot DPR_\beta \\ < 0, 0 \end{cases}, \quad (19)$$

- **Depreciation & Amortisation**

In order to determine values for d_β^n, I_β^n and τ_β^n, Asset Values (i.e. Capital Costs) first need to be defined for Generation $(X_G^{n=0})$ and Retail $(X_R^{n=0})$. Upfront and ongoing Capital costs (X_β^n, x_β^n) give rise to tax depreciation (d_β^i) such that if the current period was greater than the plant life under taxation law (*L*), then the value is 0:

$$d_G^n = \left(\frac{X_G^{n=0}}{L}\right) + \left(\frac{\sum_{n=1}^{|Y|} x_G^n}{\sum_{n=1}^{|Y|} L-(n-1)}\right) \wedge d_R^n = \left(\frac{(1-gw_R)\cdot X_R^{n=0}}{L}\right) + \left(\frac{\sum_{n=1}^{|Y|} x_R^n}{\sum_{n=1}^{|Y|} L-(n-1)}\right), \quad (20)$$

Where

gw_R is assets ascribed to Goodwill and is *not* depreciable.

- **Taxation**

Taxation (τ_β^n) payable at the corporate taxation rate (τ_c) is applied to $EBITDA_\beta^n$ less Interest (I_β^n) later defined, less d_β^n. To the extent (τ_β^n) results in non-positive outcome, tax losses $(\bar{\tau}_\beta^n)$ are carried forward and offset against future periods.

$$\tau_\beta^n = Max(0, (EBITDA_\beta^n - I_\beta^n - d_\beta^n - \bar{\tau}_\beta^{n-1}).\tau_c) \quad (21)$$

$$\bar{\tau}_\beta^n = Min(0, (EBITDA_\beta^n - I_\beta^n - d_\beta^n - \bar{\tau}_\beta^{n-1}).\tau_c) \quad (22)$$

- **Debt Structuring**

The debt financing module computes interest and principal repayments on different debt facilities depending on the type, structure and tenor of tranches. Two types exist (a) BBB-rated Corporate Facilities (CF) (i.e. balance-sheet financings) and (b) Project Financings (PF). Two structures exist – 'A' and 'B' Facilities ('Amortising' and 'Bullet', respectively), 'A' being semi-permanent with a nominal repayment tenor of 25 years. The decision tree for the two tranches of debt is the same, so for the Debt Tranche where DT = 1 or 2, the calculation is as follows:

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[28] These include including renewable program subsidies, technology set-side schemes, carbon taxes, rooftop solar PV Feed-in Tariff Subsidies, Frequency Control Ancillary Services, Market Operator Fees and transmission system losses. In 2004/05 these costs collectively added to $6.78/MWh and by 2018/19 had risen to $31.07/MWh. 80% of the cost increases related to renewable program subsidies (refer Fig.6) with the balance being largely in line with inflation.

[29] These include Retail Operating Costs ($/customer), Marketing Costs (including Customer Retention and Acquisition costs, $/customer), and General & Administrative expenses. Bad debts are also included, at 1% of sales per annum.

$$if\ n \begin{cases} > 1, DT_{\beta}^{n} = DT_{\beta}^{n-1} - P_{\beta}^{n-1} \\ = 1, DT_{\beta}^{1} = D_{\beta}^{0}.\Phi \end{cases} \tag{23}$$

D_{β}^{0} refers to the total amount of debt used in the project. The split (Φ) of debt between Facilities refers to the manner in which debt is apportioned to each Tranche. In the model, 35% of debt is assigned to Tranche 1. Principal P_{β}^{n-1} refers to the amount of principal repayment for tranche *DT* in period *n* and is calculated as an annuity:

$$P_{\beta}^{n} = \left(\frac{DT_{\beta}^{n}}{\left[\frac{1-(1+(R_{T\beta}^{z}+C_{T\beta}^{z}))^{-n}}{R_{T\beta}^{z}+C_{T\beta}^{z}}\right]} \middle| z \begin{cases} = CF \\ = PF \end{cases} \right) \tag{24}$$

In (24), $R_{T\beta}$ is the relevant interest rate swap and $C_{T\beta}$ is the credit spread or margin relevant to the issued Debt Tranche. Interest costs $\left(I_{\beta}^{n}\right)$ are calculated as the product of the (fixed) interest rate on the loan by the amount of loan outstanding:

$$I_{\beta}^{n} = DT_{\beta}^{n} \times (R_{T\beta}^{z} + C_{T\beta}^{z}) \tag{25}$$

Total Debt outstanding D_{β}^{n}, total Interest I_{β}^{n} and total Principle P_{β}^{n} are calculated as the sum of the above components for the two debt Tranches. For clarity, Loan Drawings are equal to D_{0}^{n} in year 0 to form the initial financing.

- **Debt Sizing**

One of the key calculations is the derivation of D_{β}^{0}. This is determined by the product of the gearing level and the initial Capital Cost $\left(X_{\beta}^{n=0}\right)$. Gearing levels are formed by applying a cash flow constraint based on credit metrics applied by capital markets and project banks for CF (i.e. BBB corporate) and PF (i.e. Project Finance), respectively:

$$if\ \beta \begin{cases} = CF, Min\left(\frac{FFO_{\beta}^{n}}{I_{\beta}^{n}}\right) \geq \mathbb{C}_{CF}^{n} \wedge Min\left(\frac{FFO_{\beta}^{n}}{D_{\beta}^{n}}\right) \geq \mathscr{g}_{CF}^{n} \forall n \middle| FFO_{\beta}^{n} = \left(EBITDA_{\beta}^{n} - I_{\beta}^{n} - \tau_{\beta}^{n} - dWC_{\beta}^{n} - x_{\beta}^{n}\right) \\ = PF, Min(DSCR_{G}^{n}) \geq \mathbb{C}_{PF}^{n}, \forall n \middle| DSCR_{G} = \frac{(EBITDA_{G}^{n} - x_{G}^{n} - \tau_{G}^{n})}{P_{G}^{n} + I_{G}^{n}} \end{cases}, \tag{26}$$

Where

FFO_{β}^{n}	= Funds From Operations (a Ratings Agency metric)
$\mathbb{C}_{CF}^{n}, \mathscr{g}_{CF}^{n}, \mathbb{C}_{PF}^{n}$	= Credit Metrics (Ratings Agencies & Project Banks)
WC_{β}^{n}	= Working Capital (i.e. Cash, Receivables, Deposits, Payables)
$DSCR_{G}^{n}$	= Debt Service Cover Ratio (Project Finance)

- **Cash Flow Statement**

Net Cash Flows are comprised of Cash Flows from Operations $\left(CFO_{\beta}^{n}\right)$, Investing $\left(CFI_{\beta}^{n}\right)$ and Financing $\left(CFF_{\beta}^{n}\right)$ activities:

$$CFI_{\beta}^{n} = CFO_{\beta}^{n} + CFI_{\beta}^{n} + CFF_{\beta}^{n} \middle| CFO_{\beta}^{n} = R_{\beta}^{n} - \left(C_{\beta}^{n} + dWC_{\beta}^{n} + I_{\beta}^{n} + \tau_{\beta}^{n}\right) \wedge CFI_{\beta}^{n} = \left(X_{\beta}^{n} + x_{\beta}^{n}\right) \wedge CFF_{\beta}^{n} = E_{\beta}^{n} + D_{\beta}^{n} - P_{\beta}^{n} - Divi_{\beta}, \tag{27}$$

where:

C_{β}^{n}	= are Cash Operating Costs $\left(MRC_{Q}^{n}, FOM_{Q}^{n}, W^{n}, OE^{n}, ROC^{n}\right)$
E_{β}^{n}	= Funds from the issue of Equities

- **Balance Sheet**

Current and Non-Current Assets $\left(CA_{\beta}^{n}, NCA_{\beta}^{n}\right)$ and Current and Non-Current Liabilities $\left(CL_{\beta}^{n}, NCL_{\beta}^{n}\right)$ are as follows:

$$CA_{\beta}^{n} = CFF_{\beta}^{n} + AR_{\beta}^{n} + CD_{\beta}^{n} \wedge NCA_{\beta}^{n} = X_{G}^{n=0} + (gw_{R} \cdot X_{R}^{n=0}) + \sum_{n=1}^{|Y|} x_{\beta}^{n} - \sum_{n=1}^{|Y|} d_{\beta}^{n} + [(1 - gw_{R}) \cdot X_{R}^{n=0}] \tag{28}$$

$$CL_{\beta}^{n} = AR_{\beta}^{n} + \left(P_{\beta}^{n+1} + I_{\beta}^{n}/4\right) + \tau_{\beta}^{n} \wedge NCL_{\beta}^{n} = \left(D_{\beta}^{n} - P_{\beta}^{n+1}\right) \tag{29}$$

Where:

AR_{β}^{n} = Receivables

Dynamic Financial Model Inputs

The purpose of this Appendix is to explain how each line item of the Dynamic Financial Model is populated.

OCGT Peaking Generator

- Profit & Loss Statement
    - Generation output: derived from the Unit Commitment Model by combining model logic with Table 5 input assumptions, AEMO 30-minute spot price data (summarised in Table 1) and daily gas price data (summarised in Table 6).
    - Revenue: Dynamic Financial Model logic. Spot sales drawn from the Unit Commitment Model. Hedges/Contracts-for-Differences are also drawn from the Unit Commitment Model via a 1MW Cap being settled for each Quarter (prices appear in Appendix III). Quantities of Caps sold are scaled in the Dynamic Financial Model according to the OCGT scenario being used, with contract cover set to 70% of capacity, which is consistent with the findings in Anderson, Hu and Winchester (2007).
    - Fuel Cost: derived from Unit Commitment Model results, and Table 5 inputs regarding plant efficiency.
    - O&M Costs: Cost inputs as outlined in Table 5.
    - Depreciation: straight line is used, useful life outlined in Table 5.
    - Financing Costs: Model Logic Appendix I (Eq.23-26) with interest rates and credit metric inputs outlined in Table 7.
    - Taxation: input defined in Table 5.
    - Dividends: Model assumes a 90% payout of available profits.
- Balance Sheet
    - Cash at Bank: Model Logic outlined in Appendix I
    - Receivables: model assumes a 42 day settlement lag, consistent with NEM practice
    - Fixed Assets: input defined in Table 5.
    - Payables: Fuel costs and O&M monthly in arrears, interest costs are quarterly in arrears, and taxation is annual in arrears
    - Term Loan A and B: Model Logic Appendix I (Eq.23-26) interest rates and credit metric inputs outlined in Table 7.
- Cash Flow Statement
    - Capex OCGT: major overhaul of each of the 3 gas turbine units is assumed to occur in Years 12, 13 and 14 respectively, at a refurbishment cost of $15m per unit (i.e. $45m in total).
    - Capital Distributions: if in any year there is a build-up of cash such that Cash At Bank will otherwise be > 30% of expected annual costs, the model returns the surplus cash to shareholders as a "Capital Distribution" (i.e. in addition to ordinary dividends of 90% of Net Profit After Tax)
    - All other line items are derived from Model Logic in Appendix I.

Energy retailer

- Profit & Loss Statement
    - Retailer Customer Numbers: Opening customer numbers are defined in Table 3. Annual customer losses are calculated by reference to the headline switching (defined in Fig.6 from AEMO data) rate *less* 2 percentage points (an assumption reflecting the benefit of incumbency). Annual customer gains are based on the headline switching rate plus a 20% (i.e. the energy retailer's approximate market share) of the natural growth in Queensland customer accounts.

- Retail Customer Load: annual data from Energy Supply Association of Australia (now Aust Energy Council) reports spanning 2005-2020. Residential customer sales appear at Table 3.2 and customer numbers appear at Table 3.1. From this, the average household load is derived. Average load is the multiplied by customer numbers. SME load is assumed to be 3x average household load.
    - Sales Revenues: Tariff data has been extracted from the Queensland Competition Authority's (QCA) annual tariff determinations, which are available on the QCA website (2005-2020). Residential load uses Tariff 11 and SME load uses Tariff 21. C&I customers at a fixed margin of $1.50/MWh per Table 3.
    - Network Costs for each segment: QCA annual tariff determinations
    - Spot Market Purchases: see Appendix I Retail Portfolio Model.
    - Hedge Costs / Contracts for Differences: see Appendix I Retail Portfolio Model. Contract prices appear in Appendix III.
    - Green Costs: This includes the costs of feed-in tariffs, renewable certificates and CO_2 tax when applicable. All costs derived from QCA's annual tariff determinations.
    - Other market costs: This includes ancillary services costs, NEM fees and system losses. All costs derived from QCA's annual tariff determinations.
    - Retail Operating Costs: energy retailer operating costs (expressed as $ per customer over time) has been derived from QCA's annual tariff determinations.
    - Customer Acquisition Costs: marketing allowance (expressed as a $ per customer over time) has been derived from QCA annual tariff determinations.
    - Bad debts: assumed to be 1% of sales
    - Depreciation: see Eq.20 in Appendix I.
    - Financing Costs: Model Logic Appendix I (Eq.23-26) with interest rates and credit metric inputs outlined in Table 7.
    - Taxation: 30%.
    - Dividends: 90% of available profits
- Balance Sheet
    - Cash at Bank: Model Logic Appendix I
    - Receivables: 90 day settlement lag for mass market, 30 day settlement lag for C&I customers
    - NEM Prudential Deposit: the deposit amount is modelled as the energy retailers (rolling) highest 42 days of NEM spot market settlements in arrears, consistent with NEM rules.
    - Fixed Assets: Table 3, note the goodwill component which is not depreciated.
    - Payables: Operating costs accrue monthly in arrears, interest quarterly in arrears and taxation annual in arrears
    - Term Loan A and B: Inputs from Table 7, and Appendix I see especially Eq.23-26.
- Cash Flow Statement
    - Capex on Retail Systems: assumed to be $2m per annum
    - Capital Distributions: if in any year there is a build-up of cash such that Cash At Bank will otherwise be > 30% of expected annual costs, return the surplus cash to shareholders as a "Capital Distribution" (i.e. in addition to ordinary dividends of 90% of Net Profit After Tax)

Qld Contract Prices 2004/05-2019/20

Base Swaps

CY	Q1	Q2	Q3	Q4	CY	FY	FY
2005	44.32	30.88	31.68	30.98	34.46	2004/05	34.46
2006	47.85	30.73	31.81	33.13	35.88	2005/06	35.31
2007	48.86	30.56	37.72	48.93	41.52	2006/07	36.09
2008	72.96	41.93	41.17	51.20	51.82	2007/08	50.39
2009	69.29	35.77	35.56	42.16	45.69	2008/09	49.36
2010	63.62	34.16	35.03	40.28	43.27	2009/10	43.87
2011	55.08	30.99	32.41	36.20	38.67	2010/11	40.35
2012	51.11	30.98	42.01	48.06	43.04	2011/12	37.67
2013	66.98	49.57	50.90	56.08	55.88	2012/13	51.66
2014	73.87	54.94	47.35	47.32	55.87	2013/14	58.95
2015	63.73	42.47	41.12	48.34	48.92	2014/15	50.21
2016	69.28	44.46	44.58	54.56	53.22	2015/16	50.80
2017	76.20	55.33	61.91	68.99	65.61	2016/17	57.67
2018	90.50	65.84	65.18	67.60	72.28	2017/18	71.81
2019	85.53	65.20	64.36	64.06	69.79	2018/19	70.88
2020	81.08	61.52	59.73	61.55	65.97	2019/20	67.76

Peak Swaps

CY	Q1	Q2	Q3	Q4	CY	FY	FY
2005	69.40	40.71	42.40	42.01	48.63	2004/05	48.63
2006	78.17	40.67	42.14	47.51	52.12	2005/06	50.81
2007	82.77	41.28	51.13	76.21	62.85	2006/07	53.42
2008	131.51	58.16	57.47	78.63	81.44	2007/08	79.25
2009	117.05	47.09	46.75	60.90	67.95	2008/09	75.06
2010	102.42	45.60	47.02	56.29	62.83	2009/10	63.92
2011	90.80	41.61	43.60	50.77	56.70	2010/11	58.93
2012	84.15	40.04	50.24	59.31	58.44	2011/12	54.64
2013	100.72	54.11	61.99	71.49	72.08	2012/13	66.10
2014	104.18	56.57	58.15	62.05	70.24	2013/14	73.56
2015	98.14	46.60	52.76	65.91	65.85	2014/15	66.24
2016	107.93	49.72	56.61	75.76	72.50	2015/16	69.08
2017	111.78	64.77	76.07	89.11	85.43	2016/17	77.23
2018	123.06	75.70	75.72	79.13	88.40	2017/18	90.99
2019	108.10	77.85	75.01	74.94	83.98	2018/19	85.20
2020	99.77	71.93	69.93	72.25	78.47	2019/20	80.41

$300 Caps

CY	Q1	Q2	Q3	Q4	CY	FY	FY
2005	12.75	6.75	7.18	6.45	8.28	2004/05	8.28
2006	16.93	5.90	6.38	6.10	8.83	2005/06	9.12
2007	20.37	5.42	6.80	10.90	10.87	2006/07	9.57
2008	29.09	5.54	5.26	11.61	12.87	2007/08	13.08
2009	36.30	5.05	4.36	10.13	13.96	2008/09	14.56
2010	32.85	4.34	4.06	8.87	12.53	2009/10	12.92
2011	22.32	4.01	4.09	8.43	9.71	2010/11	9.81
2012	17.09	2.80	3.66	7.21	7.69	2011/12	8.10
2013	14.96	3.01	3.46	6.98	7.10	2012/13	7.21
2014	14.27	3.00	3.60	6.66	6.88	2013/14	6.93
2015	13.91	3.31	3.67	8.53	7.36	2014/15	6.87
2016	18.57	4.02	4.39	10.48	9.37	2015/16	8.70
2017	21.82	5.11	5.48	10.92	10.84	2016/17	10.45
2018	21.47	4.95	4.57	7.98	9.74	2017/18	10.71
2019	16.32	4.04	3.80	5.44	7.40	2018/19	8.23
2020	13.46	3.29	3.37	4.48	6.15	2019/20	6.50