Griffith UNIVERSITY
Griffith Business School
Queensland, Australia

Incomplete markets, pumped hydro storage and the role of policy in Australia's National Electricity Market

Paul Simshauser[♦,♣] and Nicholas Gohdes[♦]
October 2024

Abstract
All credible scenarios of a decarbonising Australian power system with high levels of renewables rely on a portfolio of flexible, dispatchable storage and firming assets. Given our current understanding of costs and prices, such portfolios are thought to include short-duration batteries, intermediate-duration pumped hydro, and gas turbines acting as a last line of defence against intermittency. Wind and solar output ultimately need to be moved through space (networks) and time (storage). However, the storage asset class with the highest energy density, pumped hydro, appears to be facing structurally high capital costs and face incomplete markets on entry. A generating portfolio that is under-weight pumped hydro may result in rising renewable curtailment rates and a greater reliance on gas-fired generation. In this article, we focus on material reductions in the carrying cost of capital-intensive, ultra-long-lived pumped hydro assets by introducing a 'semi-regulated' policy framework to address incomplete markets in Australia's deregulated energy-only power system. When the policy is applied, financing costs are lowered significantly. We find that post-arbitrage carrying costs of pumped hydro can be reduced by almost 40%, lowering expected prices for consumers.

Keywords: pumped hydro, energy storage, energy-only markets.

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

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

Centre for Applied Energy Economics and Policy Research

1. Introduction

Decarbonisation of Australia's National Electricity Market (NEM) commenced with the task of replacing 30GW of coal-fired plant. During 2016-2024, 25GW of renewables across 167 projects reached financial close, representing $54.8[1] billion of investment[2]. Over the same period, ~16GW of rooftop solar PV was also installed. This extraordinary run-up in Variable Renewable Energy (VRE) capacity, and the prevalence of utility-scale and rooftop solar in particular, is altering the traditional operating duties undertaken by power stations. Base, intermediate and peaking duties are now progressively transitioning to a new set of asset classes comprising; VRE (solar and wind), dispatchable firming capacity viz. short-duration batteries, intermediate-duration pumped hydro and gas turbines (the last line of defence). This is more than a theoretical observation. From 2016-2024, 10GW of batteries, pumped hydro and gas turbines reached financial commitment across 48 separate projects, representing ~$28.2 billion of investment.

The inflexibility of coal plant (i.e. minimum stable loads) is incompatible with high levels of intermittent renewables, especially in solar rich regions (Simshauser and Wild, 2024). Sharply rising levels of low-cost utility-scale and rooftop solar PV tend to increase the frequency of negative spot price events, which are antithetical to the continued operation of coal-fired generation. Conversely, these same conditions provide ideal arbitrage opportunities for storage technologies, including batteries and pumped hydro.

Coal plant exit and displacement by comparatively low-capacity factor VRE involves a complex balancing task. Given the intermittent nature of renewables, limits to diurnal reliability and the fact that many periods experience vast surpluses of wind and solar relative to aggregate final demand, the need and benefit of storage capacity is axiomatic. Unsurprisingly, interest in flexible firming capacity, and storage in particular, has become a crucial topic globally (Javed et al., 2020; Stocks et al., 2021; Yang & Yang, 2019). To generalise a vast literature, it is broadly accepted no single generation technology can mitigate intermittency, maintain grid stability (viz. frequency, inertia, voltage, system strength) and ensure security of supply (Javed et al., 2020; Gilmore et al., 2023).

There has been a significant worldwide revival of interest in pumped hydro (Blakers *et al.*, 2021). But pumped hydro schemes still face significant development hurdles including environmental approvals, community reactions to inundation, access to shared transmission networks and the inevitable financing issues associated with very capital-intensive, ultra long-lived assets.

Dam development – a central component of pumped hydro projects – have a long history of cost overruns in Australia and elsewhere. Petheram and McMahon's (2019) analysis of 98 Australian dam constructions since 1888 found systemic biases towards under-forecasting capital costs – the median cost blowout was 49%. Ansar et al. (2014) found worldwide median cost overruns of 27% (see also Callegari et al., 2018).[3] Australia's 2GW Snowy 2.0 project now has a $12 billion total budget, as does the 2GW (48GWh) Borumba project – having started at half these amounts.

Prima facie, the capital-intensive nature of pumped hydro, ultra-long useful lives, indeterminate payback periods, complexity of navigating biodiversity and community challenges and the *iron law of mega-projects,* viz. over time, over budget, every time (Flyvbjerg, 2017) – might suggest 'capital-lite' options such as short-duration batteries and open-cycle gas turbines (OCGTs) would dominate firming investment commitments. And thus far in Australia's NEM, they have. However, we note 4 compelling reasons for why pumped hydro assets should be pursued:

[1] All values are denoted in $AUD unless otherwise specified
[2] From an updated version of the database contained in Simshauser and Gilmore (2022).
[3] The exception to the rule was North America with a median capital cost overrun of 11%.

1. With ongoing VRE investments, coal plant exit is predictable. Yet looming episodes of 'intractable dispatch' (Simshauser & Wild, 2024) suggest decisions on flexible firming and storage capacity additions to replace the coal fleet may need to be made rather urgently if they are to enter into service on a timely basis (given long development timeframes).

2. In the NEM, 6GW of batteries have reached financial close during 2024. Battery investments are dominated by two-hour storage configurations due to energy market prices and plant costs (with 4-hour systems seemingly now emerging in development stages). There is no question 2-4 hour storage assets help power system resilience. But short duration storage provides limited support for inter-day intermittency.

3. The last line of defence vis-à-vis power system security in NEM planning models typically comprises a large fleet gas turbines to manage inter-day and seasonal intermittency. Gas turbines will unquestionably play a vital role. But there are practical limits to Australia's natural gas pipeline and storage networks[4].

4. Ongoing VRE entry results in increasing levels of 'renewable spill' or curtailment given stubbornly inelastic power system aggregate final demand. Rising curtailment rates are a lead indicator of stalled VRE investment (Du and Rubin, 2018). Deployment of storage assets *at scale* may alleviate the most acute effects of VRE curtailment (Chyong and Newbery, 2022), thus ensuring new entrant renewables deployment occurs at lowest levelized cost by maintaining wind and solar annual capacity factors at close to optimum levels.

By mid-2024, Australia's NEM had just over 800MW // 11.3GWh of pumped hydro in-service, 2.4GW // 350GWh under construction and a pipeline of 16.6GW // 250GWh in various stages of planning. The latest NEM-wide Integrated System Plan[5] produced by the market operator includes ~8GW as optimal. The Queensland Government forecasts a range of 5-7GW[6]. Results in Gilmore (2024) span a range of 4-11 GW with median storage of ~18-23 hours. In NEM power system modelling, a core level of intermediate pumped hydro storage (i.e. greater than 8 hours) is quite resilient to recent estimates involving substantially elevated capital costs. Worldwide, additions of pumped hydro plant during 2022 totalled 10GW, and the known global project pipeline exceeds 200GW (IHA, 2023). It would seem intermediate duration storage at scale, for which pumped hydro remains the prevailing least-cost technology, may play a critical role a decarbonised NEM.

However, there is a commercial complexity for pumped hydro plant in Australia's NEM due to inherent market design features. Australia's organised spot and forward derivatives markets (comprising futures, swaps and cap contracts) adequately telegraphs signals short duration storage through a rising number of negative price events, and via the traded price of the highly liquid $300 Cap contract (a one-way Contract-for-Difference with a $300 strike price – the NEM's equivalent of a capacity market). However, there is no market signal for 'intermediate duration storage' because such duties are not currently required within the functioning timeframes of the NEM's forward markets (i.e. ~3 years).

In consequence, the NEM's organised spot and forward markets currently guide investments towards 'capacity over storage'[7]. That is, all else equal, investors would *currently* favour a 1000MW, 8 hour

[4] See in particular Simshauser and Gilmore (2024).
[5] See AEMO at https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp
[6] See Qld Government at https://www.epw.qld.gov.au/__data/assets/pdf_file/0030/32988/queensland-supergrid-infrastructure-blueprint.pdf
[7] In discussions with pumped hydro proponents, often it is the case that potential storage of the upper dam is fixed (e.g. 10,000MWh of storage equivalence) but plant capacity can be varied (e.g. 2 x 250MW with 20 hours runtime, or 4 x 250MW with 10 hours runtime).

pumped hydro over a 500MW, 16-hour configuration even though the former involves higher underlying capital outlays (i.e. same storage costs, but higher total plant costs through additional installed capacity).

To summarise, the NEM's organised spot and forward markets, designed in the 1990s, still exhibit the characteristics and market fundamentals of 'soon to be, but not yet retired' baseload coal-fired generation. Spot and forward price formation currently provides only a dim reflection of the firming and storage task ahead in a very high VRE market share power system. The true value of storage has not been revealed because remnant coal plant continue to undertake firming duties, and the storage task is currently being provided (or masked) by their *vast* coal stockpiles. In short, the NEM currently has an incomplete market for intermediate duration storage[8].

In this article, we analyse a 2GW (24-hour) pumped hydro scheme in Australia's NEM. We assume the plant has a useful life of ~100 years with an all-in capital cost of $6000/kW in real 2024 dollars. Our focus is on optimal financing with an objective of radically reducing the carrying cost of storage capacity additions by observing, then modifying, existing market design conventions. Our emphasis is on intermediate (i.e. inter-day) duration storage given its criticality to a well-functioning market post-coal retirement. While we focus on pumped hydro, our constructs may readily apply to any storage technology, including intermediate duration batteries. Our aim is to help bridge intermediate storage economics with what are likely to be transitioning forward markets and relative forward market prices.

Our results can be summarised as follows. Conventional financing is uneconomic for intermediate duration storage given the NEM's current market design, even for the most successful vertically integrated merchant utility. We examine a policy involving credit-wrapped, zero-spread (i.e. no credit margin) long-dated Commonwealth Government bonds. Such financing appears capable of *materially reducing* the 'price gap' that exists between existing market benchmarks for conventional plant capacity, and intermediate duration storage. We believe that a thoughtful application of such a policy may be leveraged to bring forward the economic viability of intermediate duration storage by 'filling' incomplete markets, thereby lowering costs for energy consumers.

This article is structured as follows. Section 2 reviews relevant literature. Sections 3 introduces our data and model, while Section 4 examines the results. Policy implications and concluding remarks follow.

2. Review of Literature

Our review of literature examines the history and revival of pumped hydro, and financing challenges in energy-only electricity markets.

2.1 Brief history and the revival of pumped hydro

Pumped hydro schemes date back to the 1890s in the Alpine regions of Switzerland, Austria and Italy (Javed et al., 2020). To summarise the technology, pumped hydro schemes comprise upper and lower reservoirs connected by a series of tunnels/pipes with reversible pumps/generators[9] (Stocks *et al.*, 2021). In the classic case, pumped hydros utilise generation overcapacity conditions in off-peak periods to pump water from the lower to the upper reservoir and in doing so create a store of potential mechanical energy (Deane et al., 2010). When aggregate demand reaches daily maximums, water is

Existing market mechanisms bias investment decision making to the higher capacity, shorter storage options (i.e. 4 x 250MW with 10 hours storage) – a product of incomplete and missing markets.

[8] To be sure, all competitive electricity markets – with their design and implementation dating back to the 1980-1990s (Schweppe et al., 1988; Pollitt, 2004) are characterised by 'missing and incomplete' markets (Newbery, 2016).

[9] Early schemes were characterised by their separate pump impellers and turbine generators. However from the 1950s the reversible pump/generator became the dominant design. See Rehman et al., (2015).

released from the upper reservoir to drive the generators which in turn undertake peaking duties (Ali et al., 2021).

Pumped hydros are characterised by high upfront capital costs (Javed *et al.*, 2020) with storage spanning from a few hours to 24+ hours (Nikolaos et al., 2023). Expected round-trip efficiency is typically ~75-82% with a reported range of 70-87% (Rehman et al., 2015). Schemes have low maintenance costs (Ali et al., 2021) and ultra-long asset lives of up to 100 years (Guittet *et al.*, 2016).

Pumped hydros were developed extensively during the 1970-80s, typically paired with inflexible baseload nuclear (Nikolaos et al., 2023) or coal plant (Guittet *et al.*, 2016). The intuition of pairing is the pumping cycle raises minimum loads in lower demand (off-peak) periods while the generating cycle matches peaking duties (Rehman et al., 2015; Stocks et al., 2021).[10]

Pumped hydro capacity additions came to a virtual halt during the 1990s (Yang and Jackson, 2011; Steffen, 2012). It was frequently assumed this halt was due to a lack of feasible sites. But as Ali et al. (2021) explain, an abundance of projects existed. Environmental permitting constraints and the rise of the low capital cost OCGT are more probable causes (Rehman et al., 2015; Guittet et al., 2016). When combined with the uncertainty of organised spot electricity markets and rising involvement of the private sector, the entry of capital-intensive, long-lived assets became problematic (see Von der Fehr and Harbord, 1995). As Offer (2018) explains, the private sector requires considerable assurances to invest in assets with payback periods beyond 15 years, the key issue being the *credit time horizon* of banks and capital markets (see also Newbery et al., 2019).

Sharply rising levels of VRE has led to a revival of interest in pumped hydro (Tuohy and O'Malley, 2011; Yang and Jackson, 2011; Steffen, 2012; Pérez-Díaz and Jiménez, 2016; Stocks et al., 2021; Nikolaos et al., 2023). The known pumped hydro project pipeline world-wide now exceeds ~200 GW (IHA, 2023). Short duration batteries are becoming increasingly prominent, but at the time of writing electrical energy storage was dominated by pumped hydro (Rehman., 2015) for plant capacity of 1000+ MW and storage of 10-600 GWh (Guittet *et al.*, 2016).[11] There are currently over 400 pumped hydro plants worldwide totalling ~190GW, including 105GW under construction (Nikolaos et al., 2023).

2.2 Pumped hydro and VRE integration

In a high renewables power system, large-scale intermediate storage will become *indispensable* for managing intermittency, and, maintaining the continuity of VRE investments (Javed *et al.*, 2020). As Newbery (2023) explains, peak-to-average output ratios for wind and solar are ~3:1 and ~4:1, respectively. There will be periods when aggregate VRE plant produces at peak levels, and in such circumstances fleet output may vastly exceed largely inelastic aggregate final electricity demand (and vice versa). In the absence of storage (in all formats) average VRE curtailment rates will steadily rise across a power system with marginal curtailment increasing at 3-4x the average rate (Newbery, 2023; Simshauser and Newbery, 2024). Rising curtailment means the unit cost of new renewable plant would rise for consumers, even after holding wind speeds and solar irradiation constant.

Pumped hydro plant are ultimately 'net users' of energy due to hydraulic and electrical losses during the round-trip cycle of power generation (Guittet *et al.*, 2016), but in a high-VRE power system they will move otherwise 'spilled' solar and wind output en-masse through time (Rehman et al., Newbery, 2018), simultaneously maintaining reliability of supply and reducing adverse effects of marginal curtailment rates for incumbent and pending VRE investors (Steffen, 2012; Nikolaos et al., 2023).

[10] Queensland's 500MW Wivenhoe pumped hydro is a case in point, developed in the 1970s, it was commissioned in 1984 along with a fleet very low-cost, baseload coal-fired generators. Tarong, Callide B and Stanwell Power Stations, which were at the time amongst the lowest cost coal-fired generators in the world.

[11] Specifically, pumped hydro represents 97% of electrical energy storage by both MW capacity (Ali et al., 2021), and MWh storage (Blakers et al., 2021; Stocks et al., 2021; Nikolaos et al., 2023).

When deployed at scale, pumped hydro can also be expected to reduce OCGT run-times (Tuohy and O'Malley, 2011) and help manage gas market loading (Simshauser and Gilmore, 2024). Material reductions in remnant thermal plant scheduling costs (ramping and unit commitment) are also predictable (Pérez-Díaz and Jiménez, 2016) given the array of generation plant non-convexities not co-optimised in organised spot electricity markets such as Australia's NEM (Sioshansi et al., 2008). Operationally, pumped hydro response times span 'minutes to seconds' (Javed *et al.*, 2020). Given the synchronous nature of pumped hydro pumps/generators and their ability to continue to spin 'dewatered', they may assist with system inertia, dynamic stability, system strength and security of supply (Rehman et al., 2015).

2.3 Incomplete and missing markets

Zafirakis et al. (2016), using price data from five deregulated EU markets, found arbitrage revenues were inadequate to cover annualised costs for pumped hydro plant. In Latin America, Delgado and Franco (2023) find a similar result with sharply rising levels of renewables. In Great Britain, Newbery (2018) observed ancillary services revenues dominated with arbitrage revenues inadequate. Chyong & Newbery (2020) found sharply rising VRE increased production duties and profits of existing pumped hydro plant when inflexible baseload plant still formed part of the plant stock. However, they also found inflexible plant exit may have the opposite effect, albeit noting operating reserves become increasingly volatile and therefore valuable. Delgado and Franco (2023) found similar patterns with and without *el nino* weather patterns in Latin America. Gilmore (2024) finds pumped hydro plant capacity factors rise in the Australian context following the exit of coal plant, but this hinges critically on commensurate rooftop and utility-scale solar PV entry at-scale.

Pumped hydros are complex, capital-intensive developments that face unusually high investment hurdles. Physical constraints aside[12], the most significant challenge is their onerous upfront capital costs. Total planned construction contingencies usually comprise 10-15% whereas outturn costs historically span +0-25% of capex plans (Nikolaos., 2023). To generalise the literature, the financial uncertainty associated with these ultra-long-lived assets present the greatest challenge (Deane et al., 2010; Yang and Jackson, 2011; Steffen, 2012). This is compounded by the fact that deregulated energy markets are characterised by missing and incomplete markets (Newbery, 2016; Simshauser, 2019; Javed et al., 2020; Nikolaos et al., 2023). Few firms appear capable of financing long-lived capital-intensive assets in deregulated electricity markets (Ali et al., 2021).

As Offer (2018) explains, the credit time horizon of project banks has limits, and as it turns out, equity and debt capital markets require more certainty for long-lived generation assets than deregulated markets appear capable of delivering – in which case its management defaults to public administration. Newbery (2018) and Nikolaos et al. (2023) note grant funding or low interest loans may be required for pumped hydro, along with a *full set* of well-designed markets to ensure the asset class is fairly compensated at the marginal value of services provided (Newbery, 2016, 2018).

This collision between the energy-only market design and applied corporate finance has led various jurisdictions to introduce strategic reserves (e.g. Belgium, Finland, Germany, Sweden and Texas) where *capacity payments* are paid to a limited number of generation units within a designated *strategic reserve*, (Holmberg and Tangeras, 2023), or introduce broad-based capacity mechanisms, such as Great Britain.[13] Bublitz et al. (2019) note that globally, organised capacity markets appear to have a growing role to overcome episodes of missing money, or unpriced tail risks. It is to be noted

[12] Those typically associated with pumped hydro schemes include land acquisition, environmental concerns (i.e. biodiversity loss), water issues and connection to the shared transmission network.
[13] Most restructured electricity markets in the U.S. commenced with organised capacity markets.

that few existing capacity mechanisms send the correct signal for optimal operation of short and intermediate duration storages during critical event days (see Holmberg and Tangers, 2023).

3. Market context, model and data

Our analysis focuses on financing intermediate duration storage (i.e. nominally 12-24 hours). The modelling sequence commences by observing the NEM's existing market conventions to begin with. We therefore start by deriving the equilibrium value for '$300 Cap' contracts.

3.1 Market context

In Australia, $300 Caps (or 'one-way' CfDs) are the NEM-equivalent of a capacity market in a large thermal power system. They are a liquid instrument traded in both the futures market and over-the-counter derivatives market. The NEM's spot price ceiling is currently A$17,500/MWh, and therefore demand for $300 Caps comes from risk-averse retail suppliers and traders seeking protection against severe price spikes. By purchasing a requisite volume of Cap contracts at the prevailing premium, these parties are able to gain effective protection from paying spot prices above the $300 strike price.

From a pricing perspective, in a market heavily oversupplied Cap premiums will trade at low values (c.$4-6/MW/h). In tight market, conditions can surge to ~$30+/MW/h. In equilibrium, Cap premiums reflect the annual 'carrying cost[14]' of the benchmark technology capable of defending such an instrument in the spot market, viz. open cycle gas turbines (Simshauser, 2020). The annualised fixed and sunk costs of such plant has historically been approximately $15/MW/h in real terms.

Our modelling sequence is set up to derive this value as a critical benchmark. Once determined, we then focus on optimising a '*post-arbitrage carrying cost'* of a pumped hydro plant which helps us to identify the value of what we shall refer to as the 'incomplete market' for intermediate duration storage.

Recall that the NEM has no market for intermediate storage, with the role technically being satisfied by vast coal stockpiles at the NEMs remaining 20GW fleet of coal-fired generators. However, if net zero is to be achieved, coal plant will exit, and so too will their stockpiles. A 10-year development timeframe in the case of pumped hydro means that by the time such signals appear through the (3-year ahead) forward markets, it will be too late. In this intervening period, policy changes are required.

Our first task is to identify the 'gap' between the existing market for $300 Caps, and the carrying cost of a pumped hydro plant. Doing so will quantify the value of the incomplete (or missing) market for intermediate duration storage. In theory, if gas turbines remain a suitable benchmark for defending $300 Caps, and if pumped hydro is the benchmark for intermediate duration storage, then the 'gap' derived is also a suitable proxy for the equilibrium price of intermediate duration storage in the NEM. For clarity, if a new technology subsequently proves superior (e.g. a very low cost, long-duration battery), the benchmark technology may well change but our *process* for deriving the proxy value of intermediate storage would not.

3.2 Model description

The main implications arising from Section 3.1 is the importance of minimising the carrying costs of pumped hydro. Pumped hydro plant are *very* capital intensive with extremely long useful lives, and so minimising the cost of capital is of the utmost importance. In the modelling process that follows, we examine different financings and energy market policies to alter how investors perceive risk, and in turn, how they would logically seek to structure a pumped hydro balance sheet in response.

[14] The carrying cost of plant capacity can be defined as the annualised fixed and sunk cost of any generation technology, including taxation expenses and a normal return to equity.

We commence with a fully merchant pumped hydro plant financed on-balance sheet in an energy-only market setting. We then move to a fully contracted project financing arrangement underwritten by a conventional Power Purchase Agreement or government CfD structure. Finally, we progress to our preferred solution, a semi-regulated plant operating in competitive markets.

To reveal the impact of these policy settings, our Project and Corporate Finance Model, known as the 'PF Model', has been adapted to accommodate various markets and policy settings, with debt and equity structuring and costs to match. For interested readers the PF Model logic is set out in detail in Appendix I – but to summarise its functionality, it is a conventional multi-year corporate finance model which produces levelized cost of electricity results for an array of financing structures and plant technologies, including batteries, gas turbines and pumped hydro plant. However, the results comprise a level of detail well beyond typical LCoE calculations because corporate (or project) finance, associated credit covenants and taxation variables are internalised and co-optimised within the model.

Within the model logic at Appendix I, of special importance to the present exercise are Eq.(14) and Eq.(15) – which generate the initial sizing of debt facilities for a given power project. The intuition behind the equations and associated constraints is simply as follows; as the quality of forward revenues are enhanced, and as the cost of debt decreases, higher leverage is obtained while maintaining all externally imposed credit metric constraints. Further, as the quantum of leverage increases, all else equal, the annualised carrying cost of the plant falls.

3.3 Data inputs

Our base scenario examines an intermediate duration (2GW, 48GWh) pumped hydro plant relevant in Australia's energy-only market setting, with ever rising levels of intermittent renewables. Plant engineering parameters required for the PF Model are listed in Table 1. Briefly, pumped hydro capital cost elements are expressed in $/kW for power (i.e. water conveyance, turbine hall, reversible pumps/turbines, generators and the substation) whereas storage reservoirs are expressed in $/kWh (see Stocks et al., 2021). A similar setup is used for battery storage. We commence with a high inherent capital cost for pumped hydro, effectively equating to $6000/kW in line with the most recent (i.e revised) cost estimates for plant of this size and scale in the NEM.[15]

Table 1: Engineering model inputs

Generation Technology		OCGT	Pumped Hydro	Battery*
Project Capacity	(MW)	250	2,000	200
- Storage Capacity	(Hrs)	-	24	24
Overnight Capital Cost	($/kW)	1,588	2,626	547
- Storage	($/kWh)	-	83	450
- Contingency		-	30%	-
Plant Capital Cost	($ M)	397	12,007	2,269
Operating Life	(Yrs)	35	100	20
Annual Capacity Factor	(%)	5.0	17-18**	26.7
Transmission Loss Factor	(MLF)	1.000	1.000	1.000
Fixed O&M	($/MW/a)	1,000	20,000	10,000
Variable O&M	($/MWh)	8.0	1.0	0.0
FCAS	(% Rev)	1.0%	1.5%	5.2-7.4%

* Degradation assumed 1.5% pa.

** See also Table 3

Source: Simshauser (2020), Gohdes (2023), AEMO 2024 Integrated System Plan.

Recall from Section 1 that existing forecasts of the NEM's optimal investment pathway (including by the Market Operator, the Queensland Government and Gilmore, 2024) include varying levels of new

[15] Table 1 includes varying operating life assumptions across the three technologies, viz. OCGT, pumped hydro and BESS. For the avoidance of doubt, cashflows are expected to cease once an asset's operating life is reached, implying a requirement for re-investment to replace decommissioned capacity

intermediate duration pumped hydro – spanning 4-11GW or $24-$66 billion of investment. Three critical variables for our modelling sequence are required from a NEM-wide power system model, viz. estimates of the annual capacity factor, unit pumping costs, and generating prices. For this, we rely on outputs from Gilmore's (2024) outlined in Table 2. To summarise, with 10GW of coal plant remaining in-service in the NEM, optimal levels of pumped hydro plant will, on average, operate with Annual Capacity Factors (ACF) of ~17%. In our discussions with developers, ACFs range from 14% through to 25% with the latter being highly dependent on high solar PV market shares. Associated pumping and generation costs/prices equate to ~$29.8/MWh (pumping) and ~$92/MWh, with dispatch prices 'capped' at $300/MWh – the explicit assumption here being that the modelled plant has sold $300 Caps and so does not benefit from extreme price spikes – instead opting for the contracted revenues which in turn aides its debt-raising capacity.

Following coal plant exit and a commensurate rise in solar PV resources, the optimal fleet of pumped hydro plant exhibit average ACFs of ~18%. Both the unit cost of pumping and capped unit dispatch prices rise marginally, as Table 2 illustrates. While the outputs from Gilmore (2024) represent a view of forecast plant performance that useful and reasonable, we note our results are *not* reliant on these assumptions. This is demonstrated in Appendix II, where sensitivities for all relevant inputs are made available.

Table 2: ACF and Pumping/Dispatch Prices

Impacted by Coal Plant Exit	Ops Yr1	Ops Yr6
Total Coal Capacity in NEM	10GW	0GW
Pumped Hydro Capacity Factor	17%	18%
Avg. Pumping Cost ($/MWh)	29.8	31.3
Avg. Dispatch Price ($/MWh)	92.0	100.5
Net Arbitrage ($/MWh)	62.2	69.2

Source: Gilmore (2024)

The final set of input assumptions comprise the financing parameters used in the model, and illustrated in Table 3. We rely on prevailing capital market rates for the 7- and 10-year debt facilities, while our benchmark equity returns for merchant and regulated assets have been derived from Gohdes (2023). Note in our preferred model of the 'semi-regulated asset' we combine these two distinct rates of equity returns.[16] Finally, debt sizing parameters are the input variables critical to the functioning of Eq.(14) and Eq.(15) of the model (as outlined in Appendix I), and are consistent with prevailing capital market parameters applied by banks and credit rating agencies relevant to Australia's NEM participants.

[16] Semi-regulated industrial organisation requires that we construct two distinct debt facilities, one serviced by regulated cashflows (regulated metrics), and one serviced by forecast merchant cashflows (merchant metrics). Total debt service obligations therefore comprise the sum of the two facilities.

Table 3: Financing model inputs

Corporate & Project Finance	2023 Avg	
- 10 Yr Commonwealth Govt Securities	3.92%	
- 7 Yr 'BBB' Corporate Bonds	6.00%	
- 7 Interest Rate Swap	4.21%	
- 7 Year Project Finance Spread	2.89%	
- 7 Yr Project Finance Term Loan A	7.10%	
Equity Returns (post tax)	Asset β*	Equity IRR
- Merchant 'Gentailer' Utility	0.60	8.5%
- Regulated Utility	0.30	7.6%
- Semi-Regulated Generator	0.48	7.9-8.2%
- PPA Project Financed Generator**	0.30	9.0%
- OCGT (Merchant Uility)	0.75	10.5%
Balance Sheet Debt Sizing	Merchant	Regulated
- BBB Rated (FFO+I)/I	4.2x	2.4x
- BBB Rated (FFO/Debt)	20-35%	>9%
- Gearing Limit	40%	66%
Project Finance Debt Sizing	Merchant	PPA
- Debt Service Cover Ratio	1.8x	1.25x
- Loan Life Cover Ratio	1.8x	1.25x
- Gearing Limit	40%	82%
- Lockup Ratio	1.35x	1.15x

* Asset β are subsequently levered to obtain Equity IRRs

** For any ultra-long-life Pumped Hydro PPA, +100 basis points is added (IRR=9%)

Sources: Simshauser and Akimov (2019), Gohdes et al. (2022, 2023)

4. Model Results

The purpose of our modelling efforts is to combine policy settings and financial engineering in order to minimise the cost of intermediate duration storage, given its critical importance to the management of intermittent renewable resources. Storage 'at-scale' will help to limit curtailment rates experienced by renewable plant through the pumping/charging cycle (meaning renewable entry costs will remain as low as possible) and will help maintain the power system in a secure and reliable state through the dispatch cycle when renewable output is low.

To begin with, our model focuses on establishing a merchant benchmark or 'base case'. Here, we assume the NEM remains in its existing format, with merchant plant entrants financing any new assets on-balance sheet. We establish benchmark carrying costs for each of the rival firming assets, viz. gas turbines, batteries and pumped hydro. Each asset is based on maintaining a 'BBB' credit rating in line with Table 2.

4.1 Base case 'benchmark' results: merchant on-balance sheet financings

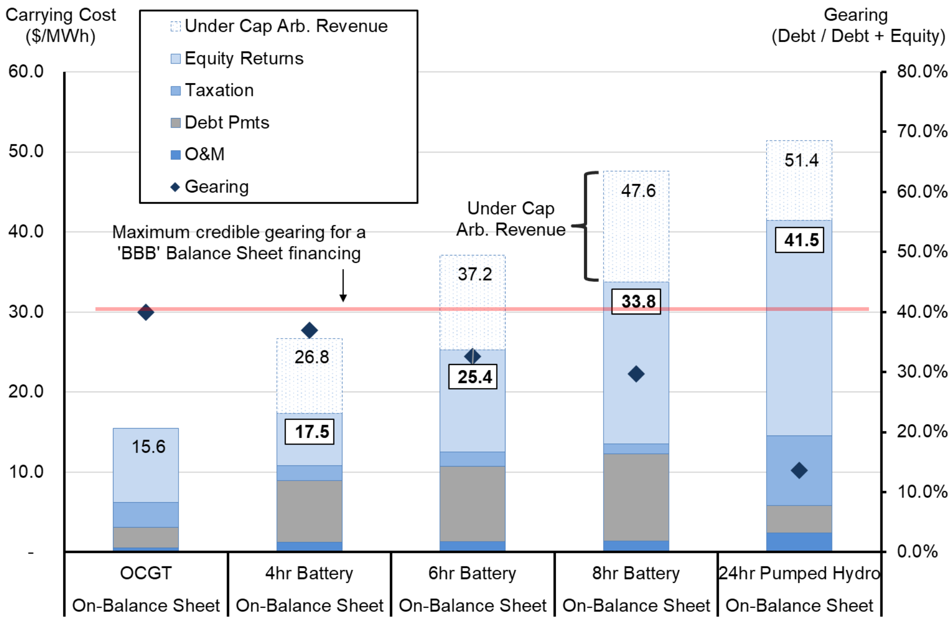
Our first set of modelled results examine merchant, on-balance sheet financed firming plant (i.e. short duration batteries, intermediate pumped hydro, gas turbines) in an energy-only market setting. This means contracted revenues will be relatively short in tenor (3 years ahead) coupled with spot market revenues – consistent with the typical merchant participant in Australia's NEM.

Given the assumptions in Tables 1-3, Figure 1 contrasts our model results for the OCGT, 4hr, 6hr and 8hr Lith-Ion batteries, and a 24hr pumped hydro.[17] The carrying cost of each technology is presented by the stacked bars (LHS y-axis), while gearing ratios are represented by the diamond markers (RHS y-axis). Note batteries and pumped hydro projects generate 'arbitrage revenues'. We have converted these 'Under Cap Arb. Revenues' to an annual equivalent value (very light blue shaded area), which in

[17] Figures 1 and 2 assume BESS charging/dispatch costs of between ~$40-45/MWh and ~$98-111/MWh, and as with pumped hydro costs and prices have been derived from Gilmore (2024).

turn is deducted from the total carrying cost to define a *'post arbitrage carrying cost'*. By contrast, OCGT plant have very high marginal running costs and low-capacity factors (~2-8%) and therefore under cap revenues will be trivial and are therefore excluded from this calculation. [18]

Figure 1: Carrying cost (on-balance sheet financings)



The first point to note in Figure 1 is the annualised fixed and sunk cost, or 'carrying cost', of the OCGT plant – at $15.6/MW/h. This is an important model result. Recall this represents a reliable proxy for the traded unit price/cost of $300 Caps 'in equilibrium'. This $15.6 model result is in turn to be used as a critical PF Model input for each of the storage technologies. That is, when modelling storage assets, we assume they sell $300 Caps, and the revenue ascribed to those forward sales is $15.6/MW/h.

This then leads us to the remaining PF Model storage results in Figure 1. Here, each plant is assumed to sell $300 Caps (at $15.6/MW/h), earning 'arbitrage revenues' in line with the charging and dispatch prices in Table 2.[19] These remaining assets are then presented with 2 x unit cost results, (i) total carrying cost, and (ii) total carrying cost net of arbitrage revenues. Our focus is on the latter. The 4-hour battery has post-arbitrage annualised fixed and sunk costs, or carrying costs, of $17.5/MW/h. It is to be noted a 4-hour battery is not theoretically capable of writing $300 Caps for its entire nameplate capacity and is therefore *not* directly comparable to an OCGT. The 6- or 8-hour battery is a better comparison – and a material gap in carrying costs exists. The gap is higher again for the 2GW // 48GWh pumped hydro, with a post-arbitrage carrying cost of $41.5/MW/h (equivalent to the carrying cost of ~9¼ hour battery under existing conditions)[20]. For the avoidance of doubt, it is expected that assets with storage durations of 6+ hours will engage in necessary dispatch behaviour to defend a quantity of Caps ~equal to their nameplate capacity.

[18] In equivalent annualised terms this might average ~$1/MWh – meaning Caps could technically be sold at $14.6 rather than $15.6/MWh to break even.
[19] The present analysis holds Cap premiums constant at $15.6/MWh throughout the period modelled. While premiums may shift over time under decarbonised market conditions, it would be unreasonable to expect a material movement sufficient to fully support viable intermediate duration storage in the near term – particularly given the urgency of the investment task.
[20] While not presented above, for interest and avoidance of doubt, the carrying cost of a 24hr Li-ion battery at current capital cost estimates equates to ~$120/MWh, net of under cap arbitrage revenue.

Regarding Fig. 1, note that *capital intensity* rises when viewing modelled assets from left to right. That is, as plant capital intensity rises (and inherent fixed and sunk costs rises commensurately), the forward sale of $300 Caps becomes an increasingly inadequate level of contracted revenue relative to optimal revenues. For example, the OCGT has virtually 100% of its unit costs covered by $300 Cap sales. In contrast, for the pumped hydro plant Cap revenues are just 48%.

Furthermore, as assets increase in capital intensity and Cap revenues decline as a % of the plant carrying cost, *serviceable* debt finance (measured by the diamond markers, RHS axis) progressively deteriorates against the maximum credible gearing obtainable, of ~40% (as BBB-rated ‘merchant’ entities). The rising inadequacy of market revenues relative to unit costs drives this result. This in turn creates a circular reasoning with respect to unit plant costs – if revenues are inadequate, gearing drops, and as gearing drops, more expensive equity is added to the capital structure, and unit costs rise further again.

Our PF Model imposes gearing limitations via the binding covenants in Eq.15 and Eq.16 in Appendix I, with the debt-to-debt+equity ratio for the pumped hydro constrained to just 14% under the base case. Equity returns are also sub-optimal, the gravity of which is intensified by under-leverage. In short, this set of results explains why the findings in Kear and Chapman (2013), Zafirakis et al., (2016), Newbery (2018b) and Delgado and Franco (2023) occur. As with these other jurisdictions, the NEM’s existing market design and policy frameworks appears unable to support merchant, intermediate-duration pumped hydro (or battery) storage.

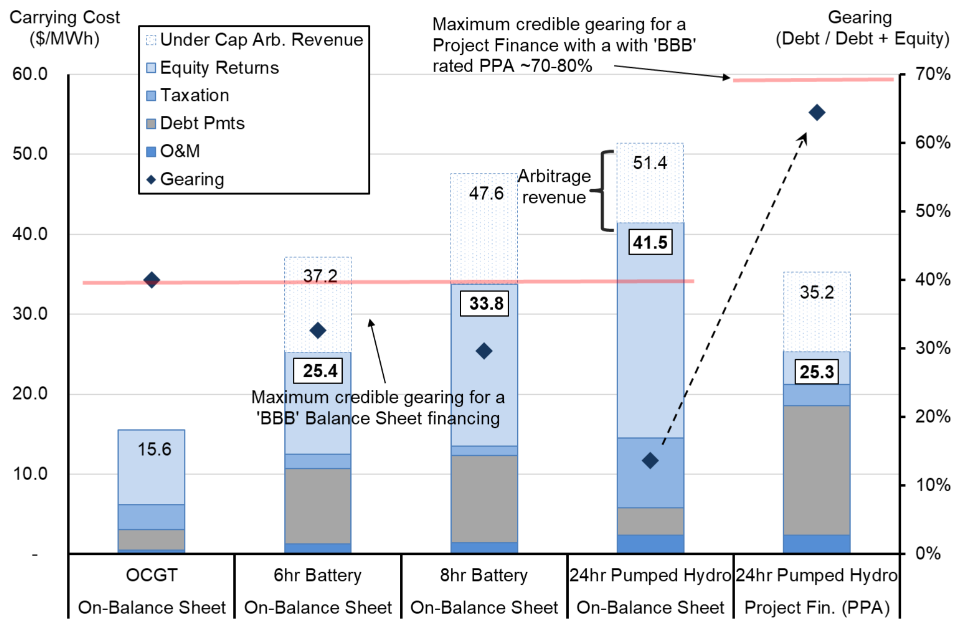
Recall from Section 1 and 2 that incomplete markets provides one explanation for this outcome along with current conditions whereby existing coal stockpiles mask the NEM’s future storage task. However, and to be clear, the optimal mix of plant derived by NEM-wide power system modelling (including by each of the Australian Energy Market Operator, the Queensland Government and Gilmore, 2024) all point towards 4-11GW of new pumped hydro plant in the mid-2030s – given our current understanding of plant technologies and technology costs.

4.2 Model results: Project financed pumped hydro with a PPA

Our next simulation analyses a switch from balance sheet financing, to a project financing. Project financings are invariably facilitated by Power Purchase Agreements (PPA) or some form of ‘tolling arrangement’. We assume the PPA covers 100% of plant capacity with the unit price dynamically co-optimised with a maximal use of project debt.

Comparative results are presented in Figure 2. Shifting to this industrial organisation and financing format reduces the pumped hydro’s post-arbitrage carrying costs by 38%, from $40.6 to $25.3/MWh. The revenue security that comes with a PPA has enabled significantly more debt to be raised within the capital structure – just as PPAs do for wind and solar PV projects (Hundt et al., 2021; Gohdes et al., 2022). To summarise, an optimised capital structure, whereby lower cost debt is maximumly exploited to lower the project’s overall Weighted Average Cost of Capital (WACC), produces a lower unit carrying cost.

Figure 2: Balance Sheet vs Project Finance



4.3 Creating a semi-regulated asset class in an energy-only market setting

Section 4.2 illustrated the beneficial impact of revenue security on the capital structure, the WACC, and the carrying cost of capital-intensive plant. While an emerging trend in the NEM has been merchant and semi-merchant VRE plant (see Simshauser, 2020; Flottmann et al., 2022; Gohdes, 2023; Gohdes et al., 2023), in practice these same WACC dynamics have led to a majority of renewables in Great Britain, Europe, the US and Australia being underwritten by PPAs or government-initiated CfDs (Newbery, 2017, 2018a, 2023; Grubb and Newbery, 2018).

A complexity of our Section 4.2 results, and the PPA scenario in particular, is the sheer size of the PPA contract itself. At 2000 MW, few if any of Australia's merchant utilities are large enough to absorb the *operating leverage* implications of such a contract in any intervening market period without adversely impacting their own credit metrics (i.e. even at $25.3/MW/h, this is well above our estimate of the equilibrium cost/price of $300 Caps at $15.6/MW/h).[21] This suggests on-market PPA transactions of this size and scale are unlikely. A government-initiated CfD could replicate the same revenue security. However, this would extract vital 'hedge firming capacity' from the forward markets – such hedge capacity being critical for the functioning of the NEM's retail market (see Flottman et al., 2024).

Consequently, our next modelling iteration seeks to capture revenue security benefits through an alternate policy pathway – by addressing the problem of incomplete markets. Australia's energy-only gross pool is a merchant market, and in NEM regions such as Queensland there are virtually no government-initiated CfD's – meaning the ~10GW of existing wind, solar and battery projects are all underwritten through bilateral, on-market PPAs or vertical investments. Moreover, as a merchant market there are no regulated revenue streams. But as Pollitt (2022, p.3) reminds us:

> *One key misunderstanding is there is no such thing as the 'free market' in the formal economy. Markets are highly regulated social institutions set up to deliver particular societal goals. So it is with the market for electricity. As such, in a modern democracy energy markets are our servants, not our masters. If the market is not delivering for society, we can change it...*

[21] Such an instrument, or a large component of it, is likely to be treated by ratings agencies as synthetic debt.

Newbery et al. (2019) observe industrial organisation within the electricity industry exhibits two business models, merchant (generation and retail) and regulated (networks). The regulated sector facilitates more secure revenues, lower debt costs and elevated gearing – all within the bounds of investment-grade credit metrics. And while there is currently no forward market for storage ($/kWh), there is no reason preventing its establishment in Australia's National Electricity Market.

One plausible policy, therefore, is to categorise intermediate duration storage reserves as a semi-regulated market, thus establishing a new revenue stream and a new asset class (i.e. 'semi-regulated assets').[22] The rationale for doing so is the central role that intermediate duration storage must play in a decarbonised power system, and the counterfactual in its absence, i.e. higher costs and prices for consumers, a potential for intractable gas market conditions (see Simshauser and Gilmore, 2024) and deteriorating investment conditions for intermittent renewables in the presence of rising marginal curtailment rates.

In this sense, noting intermediate duration storage lowers renewable entry costs and contributes to maintaining the power system in a secure and reliable state during prolonged periods of low VRE output, pumped hydro presents more closely as a *'public good'*, and therefore may be better suited to a semi-regulated arrangement for the 'extended duration'.[23] Specifically, the market may well deliver 6-8 hour pumped hydro plant but it is unlikely to deliver 24 hour storages – in spite of the looming need (see for example Queensland Government, 2022).

A semi-regulated asset class would involve the plant arbitrage function remaining merchant, with operators continuing to forward sell plant capacity. Revenues would therefore arise from the forward sale of $300 Caps, arbitrage revenues in the spot market (capped at $300/MWh) and a regulated 'intermediate storage' revenue.

In aggregate, the combination of these revenue streams creates a semi-regulated asset class. Adding a storage market to Australia's NEM by way of a certificated scheme has previously been explored in Mountain et al., (2022) with their framework being analogous to Australia's Renewable Energy Target (i.e. administratively determined quantities, competitive market prices). By comparison, our concept is clearly *blunt* in application because storage would be 'banded' (i.e. limited to intermediate- and long-duration assets) with the GWh quantity administratively determined – the design intent being to lower the cost of capital for these very capital-intensive, extremely long-lived (100+ year) plant with virtually indeterminant payback periods.

In our PF Model, we proceed by introducing the third discrete income stream as outlined above, the intermediate-duration regulated storage revenues, funded by the consumer rate-base in a manner broadly consistent with Newbery et al. (2019).

4.4 Model results: semi-regulated pumped hydro, on-balance sheet financing

In this modelled scenario, pumped hydro plant reverts to an on-balance sheet financing (constrained by 'BBB' credit metrics) with a broader suite of revenues designed to minimise the carrying cost of capacity, viz. the incorporation of a 'regulated storage' service. Revenue streams for the 'semi-regulated' intermediate duration storage asset now comprise the following:

[22] See for example https://www.drax.com/press_release/drax-given-green-light-for-new-500-million-underground-pumped-storage-hydro-plant/

[23] One of our peers queried our use of the term "public good" to describe intermediate duration storage. Our experience in speaking with pumped hydro proponents is that private investment planning systematically falls short of system requirements. In short, storage duration of 12hrs + is not currently deemed commercial. Our view is that this is a product of missing and incomplete markets, given the storage task for ahead has not yet been revealed. Moreover, it is difficult (if not impossible) for markets to manage rare, sever events which may only occur once in a decade. The severity of such events justifies policy intervention, with storage of 12+hrs hence representing the "public good".

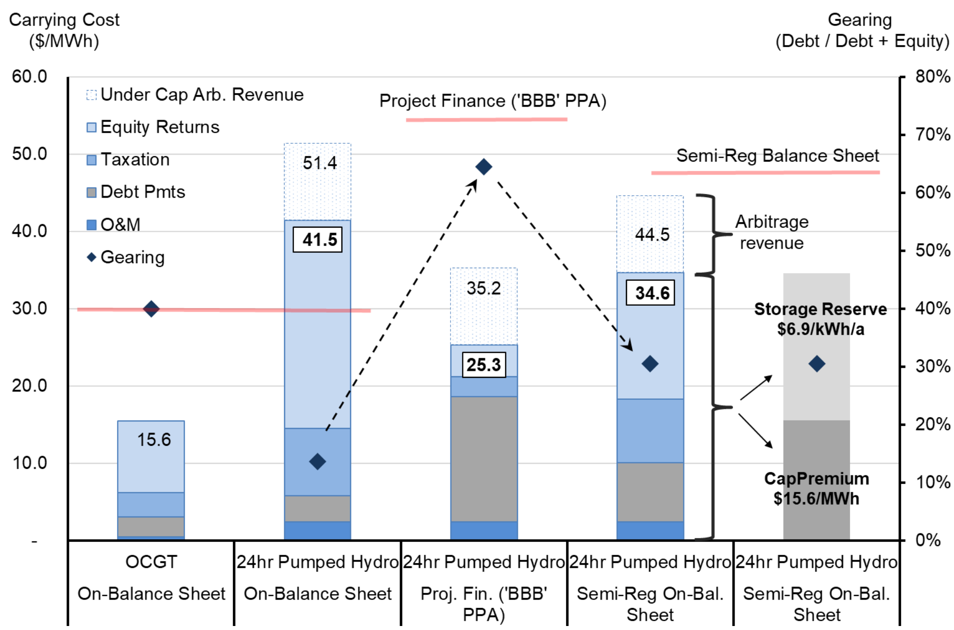
- merchant spot market arbitrage revenues, capped at $300;
- forward sale of $300 Caps from the NEM's existing forward market; and
- A regulated 'storage reserve' revenues ($/kWh), designed to cover the difference between the efficient post-arbitrage carrying cost of intermediate storage, and $300 Caps in equilibrium.

Collectively, these measures simulate the economic impact of a *quasi-PPA* with long-dated security for ~77% of net revenues (storage reserve 42%, and shorter-dated $300 Caps, 35%) which collectively enables higher gearing levels and a normal return to equity for the semi-regulated asset class. In exchange for the regulated revenue stream, plant operators would be bound by certain conventions.[24]

Fig.3 illustrates the net effect of creating this semi-regulated asset class (see 4th stacked bar series) and contrasts these with prior results. The 4th bar outlines the cost stack as measured by the carrying cost at $34.6/MW/h and gearing ratio of ~30%. This result falls short of the project financing, in exchange for keeping the plant 'on-market'.

In Fig.3, the 5th bar series is the most crucial as it translates the carrying cost into the merchant and the regulated markets. The base amount of $15.6/MW/h is earned through merchant markets by way of forward $300 Cap sales. The balance of the cost stack is the regulated storage charge ($/kWh/a). And as outlined in Section 4.5, is derived as the difference between the post arbitrage carrying cost of plant *less* the fair value of $300 Caps in equilibrium. Given a 2000 MW pumped hydro plant with 48GWh of storage, this equates to $6.9/kWh/a.

Figure 3: Semi-regulated asset



[24] It is beyond the scope of this article to identify these in detail, but we would envisage some form of constraint over bids and offer prices in line with the long-term interests of consumers, transparency of any constraints, and requirements to maintain certain storage reserves as the power system approaches critical events in exchange for the regulated revenue stream.

4.5 Model results: semi-regulated asset with a 3-Party Covenant Financing

The world of corporate finance places credit time horizons on assets, and this creates entry frictions for any plant with an ultra-long asset life. During the era of falling and low interest rates (in Australia, nominally 2012-2022) credit time horizons extended from ~15 to 25+ years. But this was always vulnerable to interest rate increases (see Offer, 2018). For very capital-intensive 100-year duration assets, viability hinges critically on the level, rate and planned tenor of (semi-permanent[25]) debt facility structures.

In our final PF Model simulation, we take the semi-regulated pumped hydro asset one step further by applying a novel policy configuration outlined in (Rosenberg *et al.*, 2004), viz. 3-Party Covenant (3PC) financing. To summarise, a 3PC financing involves issuance of 10-year Commonwealth Government bonds (with no credit spread or 'margin') - secured by way of a *credit-wrap* by the electricity consumer rate base. To maximise the level of debt within the capital structure, the semi-regulated charge is extended from covering the intermediate storage reserve (of $6.9/kWh/a in Fig.3) to the total post-arbitrage carrying cost, comprising both the $300 Cap ($15.6/MWh) and storage reserve ($6.9/kWh/a). This may appear a subtle change, but synthetically replicates a government-initiated CfD over both sold $300 Caps[26] and the intermediate storage reserve component. This expands the long-term secured revenue from 42% to 72% and predictably, facilitates higher levels of debt in the capital structure in the same way a PPA does for a project financing.

3PC financings are first and foremost a 'credit wrap'. The credit wrap is designed to reduce (or in this case, eliminate) credit spreads and increase debt levels. Credit wrapped financings have long existed in various formats across a variety of infrastructure assets (Smith and Warner, 1979; Kahan and Tuckman, 1993; Diggle et al., 2004; Rosenberg *et al.*, 2004).
If a pumped hydro is credit-wrapped by the consumer rate base (e.g. enforced through State-based legislation), then Commonwealth Government Securities (i.e. 10-Year Bonds) are capable of being originated without impacting the Commonwealth Government's sovereign credit rating. 3PC financing in turn enhances the credit quality of pumped hydro, lower the 'public good cost' of requisite intermediate duration storage, and creates a policy mechanism to resolve storage in a timely manner.

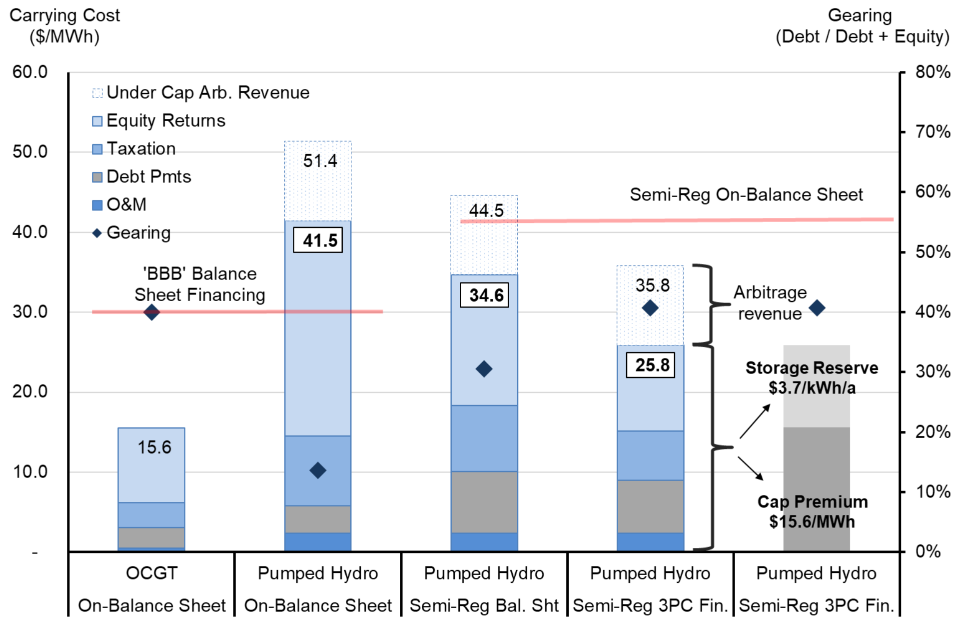
As Rosenberg et al., (2004) note, the policy architecture involves financially engineering the cost of debt, and level of debt, through reorganising the allocation of power project financial risk. The concept is analogous to Monoline Insurers[27] wrapping the corporate bond issues of Australian regulated utilities during the 2000s – the result being lenders had additional recourse to credit wrappers (i.e. the Monolines) while the issuer (i.e. Australian regulated utilities) achieved materially lower costs of debt finance (see Chava and Roberts, 2008).

Our 3PC policy result is highlighted in Fig.4. The carrying cost of plant is reduced significantly by comparison to our starting point of $41.5/MW/h, falling by ~40% to $25.8/MW/h (equivalent to the carrying cost of ~6 hour battery under existing conditions). Gearing rises from 14% to ~42% which lies within the viable range for our semi-regulated utility benchmark (~40-55%) and above merchant

[25] A semi-permanent debt facility is one in which the principal is not fully repaid at the end of the loan tenor. This means principal repayments are lower for equity investors, but introduces a non-trivial refinancing risk for debt investors.
[26] If the price of Caps fell below $15.6/MWh, regulated revenues would expand via the CfD to cover any gap. Conversely, if Cap prices rose above $15.6/MWh (a plausible scenario in a decarbonised NEM), regulated revenues would be returned to consumers – thus operating as a financial shock absorber.
[27] Monolines were 'AAA' rated insurance companies which provided credit wraps to bond issues of regulated utilities (BBB rated). More than $6 billion of debt issued by Australian electricity and gas utilities (e.g. United Energy, Powercor, Citipower, ETSA Utilities, Basslink, ElectraNet, Envestra) were wrapped by the monolines (e.g. Ambac, FSA, XLCA, MBIA), reducing spreads from 100+bps to ~40bps over swap rates.

utilities (~35%). Furthermore, the cost of the intermediate storage reserve is reduced from $6.9/kWh/a in Fig.3, to $3.7/kWh/a in Fig.4.[28]

Figure 4: Semi-regulated with a 3PC Policy



Tab.4 compares the storage assets we have modelled, with Column 2 setting out the initial capital cost of storage ($/kWh), Column 3 reveals the annual cost of storage, the 4th column highlights the value earned through the sale of $300 Caps given existing markets in equilibrium, while the final column identifies the missing money arising from incomplete markets. If our incomplete market (i.e. intermediate duration storage reserve) and financing policy (i.e. 3PC) were formalised as energy policy mechanisms, then the cost of intermediate duration storage can be reduced very substantially (from $9.4/kWh.a to $3.7/kWh.a) as Tab.4 illustrates.

Table 4: Storage costs incl. 3PC Policy ($/kWh/a)

	Capital Cost of Storage	Annual Storage Cost	Cap Premium Equivalent*	Net Storage Cost
Column	2	3	4	5 = (3 - 4)
	($/kWh)	($/kWh/a)	($/kWh/a)	($/kWh.a)
4 Hr Battery	723.5	38.2	3.8	34.5
6 Hr Battery	586.8	37.0	5.7	31.3
8 Hr Battery	518.4	37.0	5.7	31.3
24 Hr Pumped Hydro	216.5	15.1	5.7	9.4
Semi Reg Pumped Hydro	216.5	12.6	5.7	6.9
3PC Pumped Hydro	216.5	9.4	5.7	3.7

* Adjusted for minimum 6 hours run time, at $15.6/MWh.

5. Policy Implications

Our quantitative results and the progressively lower carrying cost of pumped hydro plant ($25.8/MW/h, Fig.4) is made possible by two distinct policy instruments, viz. an intermediate duration storage ‘service’ which is remunerated by regulated revenues, and the financial engineering associated with

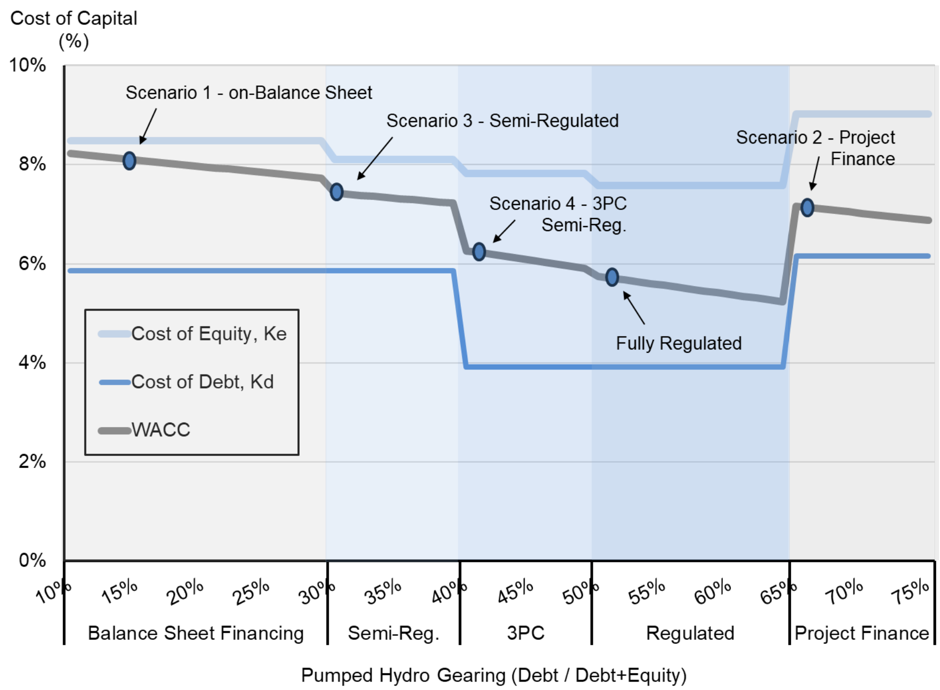
[28] For completeness, the same analysis was conducted for a 24hr BESS using forecast 2035 capex costs. Based on the best available Australian data from the AEMO 2024 Integrated System Plan, our results indicate that similar cost savings can be achieved for BESS under a 3PC structure – lowering post arbitrage carrying costs by c.30% from c.$75.0/MW/h to c.$54.0/MWh/h

the 3PC policy. Collectively, the headline carrying cost of intermediate duration storage seems capable of being reduced by almost 40%, from $41.5/MW/h as an unviable merchant plant, to $25.8/MW/h under our preferred model – the 'semi-regulated 3PC' plant. And within this carrying cost, the annualised cost of storage reduces from $9.4 to $3.7/kWh.a.

Noting the underlying construction and operational cost of plant was held constant in all scenarios, how reductions in the carrying cost were achieved is set out conceptually in Fig.5. The x-axis in Fig.5 plots gearing levels and the y-axis measures the cost of capital. Revenue quality matters and ultimately drives the quantity, and price, of debt (gearing) in the pursuit of the optimal capital structure and overall weighted average cost of capital.

One further proposition might be a government-initiated CfD for 100% of plant capacity and output. While not illustrated, we modelled a fully regulated asset which further reduced the carrying cost, to ~$23.0/MW/h. However, a 100% CfD also extracts the plant capacity from forward hedge markets. Our preferred option, the 'semi-regulated plant' facilitated by the 3PC policy, would remain an *active market participant* and critically, provide the vital repackaging of intermittent VRE output into useable forward products for customers.

Figure 5: Stylised Weighted Average Cost of Capital



6. Concluding remarks

Energy markets were designed in the 1980-1990s with an objective of maximising productive, allocative and dynamic efficiency in power systems typically characterised by over-capacity and prices above efficient levels. Most policymakers accept our 1990s designed markets are incomplete for the decarbonisation task ahead, and in particular, the storage required. That said, short duration storage assets, with their relatively quick paybacks, seem to sit well within our existing (energy-only) market designs. In Australia's NEM, more than 8.4GW has been committed over the past 4 years, with a further 3GW expected to reach construction during 2024 alone. However, virtually all of this capacity is ~2 hours in duration.

With few exceptions, Australia's 1990s-designed NEM has not delivered capital-intensive merchant assets with longer payback periods. This includes intermediate duration storage of 15+ hours. Given incomplete markets, the payback for an intermediate duration pumped hydro plant is indeterminate and sits beyond the credit time horizon of investors and banks. Uncertainty over future prices, future energy policy, future storage technologies and future political changes are simply too great for investors to navigate.

Some minimum level of certainty is required by project banks and capital markets. But this same level of certainty is *not required* by central planners and policymakers (Offer, 2018). A primary task of power system planners and policymakers is to manage the complexity and uncertainty of spot and forward commodity (electricity) markets that are unable to be managed by the debt and equity capital markets.

That some risks are too difficult for the capital markets to navigate is not an indictment of our energy markets during an episode of power system transformation. Energy markets and the agents operating within them can be expected to achieve efficient outcomes under conditions of relative stability and within the credit time horizon applied by banks, bond investors and the institutional equity capital markets. Beyond this boundary, some form of policy intervention is required such as public ownership, retention of private sector involvement through subsidies, regulatory charges or awarding monopoly franchises (Offer, 2018; Newbery et al., 2019).

Just because intermediate duration storage has indeterminate payback periods given existing energy market designs does not mean such assets are not economic. But long lead times for development and construction means commitment decisions required now will struggle commercially. The difference between economic and commercial can be identified by the 'public good' of an asset class.

The intermittency of VRE means intermediate duration storage is necessary. And until markets are able to accurately price such services, a large component of these assets may best be considered a public good, requiring policy guidance. As is the case with other public goods such as national defence, the role of government is to determine the quantity needed to manage the stated risk, to nominate an authority to provide the good, and then spread costs as far and wide as possible across the tax base – or in this instance, the electricity rate base, to minimise cost impacts. Adding a storage service to the NEM (noting the vast solar resources of Australia) and the 3PC policy, is designed for this purpose. Meanwhile, assets that sit within the credit time horizon of banks (i.e. solar, wind, OCGTs and short duration storage) can, and should, continue to be successfully undertaken within the existing market design.

7. References

Ali, S., Stewart, R.A. and Sahin, O. (2021) 'Drivers and barriers to the deployment of pumped hydro energy storage applications: Systematic literature review', *Cleaner Engineering and Technology*. Elsevier Ltd. Available at: https://doi.org/10.1016/j.clet.2021.100281.

Ansar, A. *et al.* (2014) 'Should we build more large dams? The actual costs of hydropower megaproject development', *Energy Policy*, 69, pp. 43–56. Available at: https://doi.org/10.1016/j.enpol.2013.10.069.

Blakers, A. *et al.* (2021) 'A review of pumped hydro energy storage', *Progress in Energy*. Institute of Physics. Available at: https://doi.org/10.1088/2516-1083/abeb5b.

Bublitz, A. *et al.* (2019) 'A survey on electricity market design : Insights from theory and real-world implementations of capacity remuneration mechanisms', *Energy Economics*, 80, pp. 1059–1078.

Callegari, C., Szklo, A. and Schaeffer, R. (2018) 'Cost overruns and delays in energy megaprojects: How big is big enough?', *Energy Policy*, 114, pp. 211–220. Available at: https://doi.org/10.1016/j.enpol.2017.11.059.

Chava, S. and Roberts, M.R. (2008) 'How does financing impact investment? the role of debt covenants', *Journal of Finance*, 63(5), pp. 2085–2121. Available at: https://doi.org/10.1111/j.1540-6261.2008.01391.x.

Chyong, C.K. and Newbery, D. (2022) 'A unit commitment and economic dispatch model of the GB electricity market – Formulation and application to hydro pumped storage', *Energy Policy*, 170. Available at: https://doi.org/10.1016/j.enpol.2022.113213.

Deane, J.P., Ó Gallachóir, B.P. and McKeogh, E.J. (2010) 'Techno-economic review of existing and new pumped hydro energy storage plant', *Renewable and Sustainable Energy Reviews*, pp. 1293–1302. Available at: https://doi.org/10.1016/j.rser.2009.11.015.

Delgado, D. and Franco, C. (2023) 'Arbitrage in an electricity market with a high share of renewables', *IEEE Latin America Transactions*, 22(1), pp. 39–45.

Diggle, J., Brooks, R. and Stewart, M. (2004) 'Credit wrapping and local infrastructure investment', *Sustaining Regions*, 4(2), pp. 39–46.

Du, X. and Rubin, O.D. (2018) 'Transition and Integration of the ERCOT Market with the Competitive Renewable Energy Zones Project', *The Energy Journal*, 39(4), pp. 235–259. Available at: https://doi.org/10.5547/01956574.39.4.orub.

Von der Fehr, N.-H. and Harbord, D. (1995) 'Capacity investment and long-run efficiency in market-based electricity industries.', in O. Olsen (ed.) *Competition in the electricity supply industry – experience from Europe and the United States*. DJ0F Publishing, Copenhagen.

Finon, D. and Pignon, V. (2008) 'Capacity mechanisms in imperfect electricity markets', *Utilities Policy*, 16(3), pp. 141–142.

Flottmann, J.H., Akimov, A. and Simshauser, P. (2022) 'Firming merchant renewable generators in Australia's National Electricity Market', *Economic Analysis and Policy*, 74, pp. 262–276. Available at: https://doi.org/10.1016/j.eap.2022.02.005.

Flyvbjerg, B. (2017) 'Introduction: The Iron Law of Megaproject Management', in B. Flyvbjerg (ed.) *The Oxford Handbook of Megaproject Management*. Oxford UK: Oxford University Press. Available at: https://www.researchgate.net/publication/299393235.

Gilmore, J. (2024) 'The optimal plant mix and the role of pumped hydro', in *CAEEPR Research Seminar on Pumped Hydro*. KWM, Brisbane, pp. 1–17.

Gilmore, J., Nelson, T. and Nolan, T. (2023) 'Firming Technologies to Reach 100% Renewable Energy Production in Australia's National Electricity Market (NEM)', *Energy Journal*, 44(6), pp. 189–210. Available at: https://doi.org/10.5547/01956574.44.6.jgil.

Gohdes, N. (2023) 'Unhedged risk in hybrid energy markets: Optimising the revenue mix of Australian solar', *Economic Analysis and Policy*, 80, pp. 1363–1380. Available at: https://doi.org/10.1016/j.eap.2023.10.004.

Gohdes, N., Simshauser, P. and Wilson, C. (2022) 'Renewable entry costs, project finance and the role of revenue quality in Australia's National Electricity Market', *Energy Economics*, 114. Available at: https://doi.org/10.1016/j.eneco.2022.106312.

Gohdes, N., Simshauser, P. and Wilson, C. (2023) 'Renewable investments, hybridised markets and the energy crisis: Optimising the CfD-merchant revenue mix', *Energy Economics*, 125, p. 106824. Available at: https://doi.org/10.1016/j.eneco.2023.106824.

Grubb, M. and Newbery, D. (2018) 'UK electricity market reform and the energy transition: Emerging lessons', *Energy Journal*, 39(6), pp. 1–25.

Guittet, M. *et al.* (2016) 'Study of the drivers and asset management of pumped-storage power plants historical and geographical perspective', *Energy*. Elsevier Ltd, pp. 560–579. Available at: https://doi.org/10.1016/j.energy.2016.04.052.

Holmberg, P. and Tangeras, T. (2023) 'A Survey of Capacity Mechanisms: Lessons for the Swedish Electricity Market', *The Energy Journal*, 44(01). Available at: https://doi.org/10.5547/01956574.44.6.phol.

Hundt, S., Jahnel, J. and Horsch, A. (2021) ‘Power Purchase Agreements and Financing Renewables: An Interdependency’, *The Journal of Structured Finance*, Spring, pp. 35–50.

Javed, M.S. *et al.* (2020) ‘Solar and wind power generation systems with pumped hydro storage: Review and future perspectives’, *Renewable Energy*. Elsevier Ltd, pp. 176–192. Available at: https://doi.org/10.1016/j.renene.2019.11.157.

Kahan, M. and Tuckman, B. (1993) *Private vs. Public Lending: Evidence from Covenants*. Available at: https://escholarship.org/uc/item/1xw4w7sk.

Kann, S. (2009) ‘Overcoming barriers to wind project finance in Australia’, *Energy Policy*, 37(8), pp. 3139–3148. Available at: https://doi.org/10.1016/j.enpol.2009.04.006.

Kear, G. and Chapman, R. (2013) ‘“Reserving judgement”: Perceptions of pumped hydro and utility-scale batteries for electricity storage and reserve generation in New Zealand’, *Renewable Energy*, 57, pp. 249–261. Available at: https://doi.org/10.1016/j.renene.2013.01.015.

Mountain, B. *et al.* (2022) *Electricity storage: the critical electricity policy challenge*. Victoria Energy Policy Centre, Victoria University. Available at: https://doi.org/10.26196/23jk-8f47.

Newbery, D. (2016) ‘Missing money and missing markets: Reliability, capacity auctions and interconnectors’, *Energy Policy*, 94(January), pp. 401–410.

Newbery, D. (2017) ‘Tales of two islands – Lessons for EU energy policy from electricity market reforms in Britain and Ireland’, *Energy Policy*, 105(June 2016), pp. 597–607.

Newbery, D. (2018a) ‘Evaluating the case for supporting renewable electricity’, *Energy Policy*, 120, pp. 684–696. Available at: https://doi.org/10.1016/j.enpol.2018.05.029.

Newbery, D. (2018b) ‘Shifting demand and supply over time and space to manage intermittent generation: The economics of electrical storage’, *Energy Policy*, 113, pp. 711–720. Available at: https://doi.org/10.1016/j.enpol.2017.11.044.

Newbery, D. *et al.* (2019) *Financing low-carbon generation in the UK: The hybrid RAB model*. EPRG Working Paper 1926, Energy Policy Research Group, University of Cambridge. Available at: https://www.gov.uk/government/consultations/regulated-asset-base-rab-model-for-nuclear.

Newbery, D. (2023) ‘High renewable electricity penetration: Marginal curtailment and market failure under “subsidy-free” entry’, *Energy Economics*, 126, p. 107011. Available at: https://doi.org/10.1016/j.eneco.2023.107011.

Newbery, D.M. and Pollitt, M.G. (1997) ‘The Restructuring and Privatisation of Britain’s CEGB - was it worth it?’, *The Journal of Industrial Economics*, 45(3), pp. 269–303.

Nikolaos, P.C., Marios, F. and Dimitris, K. (2023) ‘A Review of Pumped Hydro Storage Systems’, *Energies*. MDPI. Available at: https://doi.org/10.3390/en16114516.

Offer, A. (2018) *Patient and impatient capital: Time horizons as market boundaries*. Discussion Papers in Economic and Social History #65, Oxford University. Available at: https://doi.org/10.1787/a31cbf4d-en.

Pérez-Díaz, J.I. and Jiménez, J. (2016) ‘Contribution of a pumped-storage hydropower plant to reduce the scheduling costs of an isolated power system with high wind power penetration’, *Energy*, 109, pp. 92–104. Available at: https://doi.org/10.1016/j.energy.2016.04.014.

Petheram, C. and McMahon, T.A. (2019) ‘Dams, dam costs and damnable cost overruns’, *Journal of Hydrology X*, 3. Available at: https://doi.org/10.1016/j.hydroa.2019.100026.

Pollitt, M.G. (2004) ‘Electricity reform in Chile: Lessons for developing countries’, *Journal of Network Industries*, 5(3–4), pp. 221–262.

Pollitt, M.G. (2022) *The Energy Market in Time of War*. Working Paper, Centre on Regulation in Europe, Brussels. Available at: https://cdn.eurelectric.org/media/6053/overview_national_situation_18082022-h-D24BA028.pdf.

Queensland Government (2022) *Optimal infrastructure pathway for the Queensland Energy and Jobs Plan*. Available at: Queensland SuperGrid Infrastructure Blueprint (epw.qld.gov.au) (Accessed: 1 October 2024).

Rehman, S., Al-Hadhrami, L.M. and Alam, M.M. (2015) 'Pumped hydro energy storage system: A technological review', *Renewable and Sustainable Energy Reviews*. Elsevier Ltd, pp. 586–598. Available at: https://doi.org/10.1016/j.rser.2014.12.040.

Rosenberg, W.G. *et al.* (2004) *Financing IGCC – 3 Party Covenant*. Available at: https://www.innovations.harvard.edu/sites/default/files/financing_igcc.pdf.

Schweppe, F.C. *et al.* (1988) *Spot Pricing of Electricity*. US: Kluwer Academic Publishers.

Simshauser, P. (2019) 'Missing money, missing policy and Resource Adequacy in Australia's National Electricity Market', *Utilities Policy*, 60, p. 100936.

Simshauser, P. (2020) 'Merchant renewables and the valuation of peaking plant in energy-only markets', *Energy Economics*, 91, p. 104888.

Simshauser, P. and Akimov, A. (2019) 'Regulated electricity networks, investment mistakes in retrospect and stranded assets under uncertainty', *Energy Economics*, 81, pp. 117–133.

Simshauser, P. and Gilmore, J. (2022) 'Climate change policy discontinuity & Australia's 2016-2021 renewable investment supercycle', *Energy Policy*, 160(August 2021), p. 112648. Available at: https://doi.org/10.1016/j.enpol.2021.112648.

Simshauser, P. and Gilmore, J. (2024) *Solving for 'y': demand shocks from Australia's gas turbine fleet*. CAEEPR Working Paper #2024-03, Centre for Applied Energy Economics & Policy Research, Griffith University. Brisbane.

Simshauser, P. and Newbery, D. (2024) 'Non-firm vs priority access: On the long run average and marginal costs of renewables in Australia', *Energy Economics*, 136, p. 107671. Available at: https://doi.org/10.1016/j.eneco.2024.107671.

Simshauser, P. and Wild, P. (2024) 'Rooftop solar PV, coal plant inflexibility and the minimum load problem', *The Energy Journal* , (In-press), pp. 1–26. Available at: doi.org/10.1177/01956574241283732 (Accessed: 30 October 2024).

Sioshansi, R., O'Neill, R. and Oren, S.S. (2008) 'Economic consequences of alternative solution methods for centralized unit commitment in day-ahead electricity markets', *IEEE Transactions on Power Systems*, 23(2), pp. 344–352. Available at: https://doi.org/10.1109/TPWRS.2008.919246.

Smith, C.W. and Warner, J.B. (1979) 'On financial contracting: an Analysis of Bond Covenants*', *Journal of Fmanctal Economtcs*, 7, pp. 117–161.

Steffen, B. (2012) 'Prospects for pumped-hydro storage in Germany', *Energy Policy*, 45, pp. 420–429. Available at: https://doi.org/10.1016/j.enpol.2012.02.052.

Stocks, M. *et al.* (2021) 'Global Atlas of Closed-Loop Pumped Hydro Energy Storage', *Joule*, 5(1), pp. 270–284. Available at: https://doi.org/10.1016/j.joule.2020.11.015.

Tuohy, A. and O'Malley, M. (2011) 'Pumped storage in systems with very high wind penetration', *Energy Policy*, 39(4), pp. 1965–1974. Available at: https://doi.org/10.1016/j.enpol.2011.01.026.

Yang, C. and Jackson, R.B. (2011) 'Opportunities and barriers to pumped-hydro energy storage in the United States', *Renewable and Sustainable Energy Reviews*, 15(1), pp. 839–844. Available at: https://doi.org/10.1016/j.rser.2010.09.020.

Yang, W. and Yang, J. (2019) 'Advantage of variable-speed pumped storage plants for mitigating wind power variations: Integrated modelling and performance assessment', *Applied Energy*, 237, pp. 720–732. Available at: https://doi.org/10.1016/j.apenergy.2018.12.090.

Zafirakis, D. *et al.* (2016) 'The value of arbitrage for energy storage: Evidence from European electricity markets', *Applied Energy*, 184, pp. 971–986. Available at: https://doi.org/10.1016/j.apenergy.2016.05.047.

Appendix I

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

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

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

$$q_j^i = CF_j^i . k^i . \left(1 - Aux^i\right) . MLF^i, \tag{2}$$

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

$$R_j^i = \left(q_j^i . p^{i\varepsilon} . \pi_j^R\right), \tag{3}$$

Marginal running costs for coal and gas plant need to be defined per Eq. (4). The thermal efficiency for each generation technology ζ^i is defined. The constant term '3600'[29] is divided by ζ^i to convert the efficiency result from % to kJ/kWh. This is then multiplied by raw fuel commodity cost f^i. Variable Operations & Maintenance costs v^i, where relevant, are added which produces a pre-carbon short run marginal cost. Under conditions of externality pricing CP_j, the CO_2 intensity of output needs to be defined. Plant carbon intensity g^i is derived by multiplying the plant heat rate by combustion emissions $\dot{g}^i$ and fugitive CO_2 emissions $\hat{g}^i$. Marginal running costs in the *j^th^* period is then calculated by the product of short run marginal production costs by generation output q_j^i and escalated at the rate of π_j^C.

$$\vartheta_j^i = \left\{\left[\left(\frac{\left(3600/\zeta^i\right)}{1000} . f^i + v^i\right) + \left(g^i . CP_j\right)\right] . q_j^i . \pi_j^C \middle| g^i = \left(\dot{g}^i + \hat{g}^i\right) . \frac{\left(3600/\zeta^i\right)}{1000}\right\}, \tag{4}$$

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

$$FOM_j^i = FC^i . k^i . \pi_j^C , \tag{5}$$

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

$$EBITDA_j^i = \left(R_j^i - \vartheta_j^i - FOM_j^i\right), \tag{6}$$

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

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

$$x_j^i = c_j^i . \pi_j^C, \quad (7)$$

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

$$d_j^i = \left(\frac{X_0^i}{L}\right) + \left(\frac{x_j^i}{L-(j-1)}\right), \quad (8)$$

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

$$\tau_j^i = Max\left(0, \left(EBITDA_j^i - I_j^i - d_j^i - L_{j-1}^i\right). \tau_c\right), \quad (9)$$

$$L_j^i = Min\left(0, \left(EBITDA_j^i - I_j^i - d_j^i - L_{j-1}^i\right). \tau_c\right), \quad (10)$$

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

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

$$if\ j \begin{cases} > 1, DT_j^i = DT_{j-1}^i - P_{j-1}^i \\ = 1, DT_1^i = D_0^i . S \end{cases} \quad (11)$$

D_0^i refers to the total amount of debt used in the project. The split (*S*) of the debt between each facility refers to the manner in which debt is apportioned to each Term Loan facility or Corporate Bond. In most model cases, 35% of debt is assigned to Term Loan B and the remainder to Term Loan A. Principal P_{j-1}^i refers to the amount of principal repayment for tranche *T* in period *j* and is calculated as an annuity:

$$P_j^i = \left(\frac{DT_j^i}{\left[\frac{1-\left(1+\left(R_{Tj}^Z + C_{Tj}^Z\right)\right)^{-n}}{R_{Tj}^Z + C_{Tj}^Z}\right]} \middle|\, z \begin{cases} = VI \\ = PF \end{cases} \right) \quad (12)$$

In (12), R_{Tj} is the relevant interest rate swap (5yr, 7yr or 12yr) and C_{Tj} is the credit spread or margin relevant to the issued Term Loan or Corporate Bond. The relevant interest payment in the *j*[th] period

$\left(I_j^i\right)$ is calculated as the product of the (fixed) interest rate on the loan or Bond by the amount of loan outstanding:

$$I_j^i = DT_j^i \times (R_{Tj}^z + C_{Tj}^z) \tag{13}$$

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

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

$$iif\ \gamma \begin{cases} = VI,\ \frac{FFO_j^i}{I_j^i} \geq \delta_j^{VI} \forall\ j\ \left| \frac{D_j^i}{EBITDA_j^i} \geq \omega_j^{VI} \forall\ j\ \right| FFO_j^i = \left(EBITDA_j^i - x_j^i\right) \\ = PF, Min\left(DSCR_j^i, LLCR_j^i\right) \geq \delta_j^{PF}, \forall\ j\ \left| DSCR_j = \frac{\left(EBITDA_j^i - x_j^i - \tau_j^i\right)}{P_j^i + I_j^i} \right| LLCR_j = \frac{\sum_{j=1}^{N}\left[\left(EBITDA_j^i - x_j^i - \tau_j^i\right).(1+K_d)^{-j}\right]}{D_j^i} \end{cases} \tag{14}$$

Credit metrics[30] $\left(\delta_j^{VI}\right)$ and $\left(\omega_j^{VI}\right)$ are exogenously determined by credit rating agencies and are outlined in Table 2. Values for δ_j^{PF} are exogenously determined by project banks and depend on technology (i.e. thermal vs. renewable) and the extent of energy market exposure, that is whether a Power Purchase Agreement exists or not. For clarity, FFO_j^i is 'Funds From Operations' while $DSCR_j^i$ and $LLCR_j^i$ are the Debt Service Cover Ratio and Loan Life Cover Ratios. Debt drawn is:

$$D_0^i = X_0^i - \sum_{j=1}^{N}\left[EBITDA_j^i - I_j^i - P_j^i - \tau_j^i\right].(1+K_e)^{-(j)} - \sum_{j=1}^{N} x_j^i.(1+K_e)^{-(j)} \tag{15}$$

At this point, all of the necessary conditions exist to produce estimates of the long run marginal cost of power generation technologies along with relevant equations to solve for the price $\left(p^{i\varepsilon}\right)$ given expected equity returns (K_e) whilst simultaneously meeting the constraints of δ_j^{VI} and ω_j^{VI} or δ_j^{PF} given the relevant business combinations. The primary objective is to expand every term which contains $p^{i\varepsilon}$. Expansion of the EBITDA and Tax terms is as follows:

$$0 = -X_0^i + \sum_{j=1}^{N}\left[\left(p^{i\varepsilon}.q_j^i.\pi_j^R\right) - \vartheta_j^i - FOM_j^i - I_j^i - P_j^i - \left(\left(p^{i\varepsilon}.q_j^i.\pi_j^R\right) - \vartheta_j^i - FOM_j^i - I_j^i - d_j^i - L_{j-1}^i\right).\tau_c\right].(1+K_e)^{-(j)} - \sum_{j=1}^{N} x_j^i.(1+K_e)^{-(j)} - D_0^i \tag{16}$$

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

Let $IRR \equiv K_e$

$$\sum_{j=1}^{N}(1-\tau_c).p^{i\varepsilon}.q_j^i.\pi_j^R.(1+K_e)^{-(j)} = X_0^i - \sum_{j=1}^{N}\left[-(1-\tau_c).\vartheta_j^i - (1-\tau_c).FOM_j^i - (1-\tau_c).\left(I_j^i\right) - P_j^i + \tau_c.d_j^i + \tau_c L_{j-1}^i).(1+K_e)^{-(j)}\right] + \sum_{j=1}^{N} x_j^i.(1+K_e)^{-(j)} + D_0^i \tag{17}$$

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

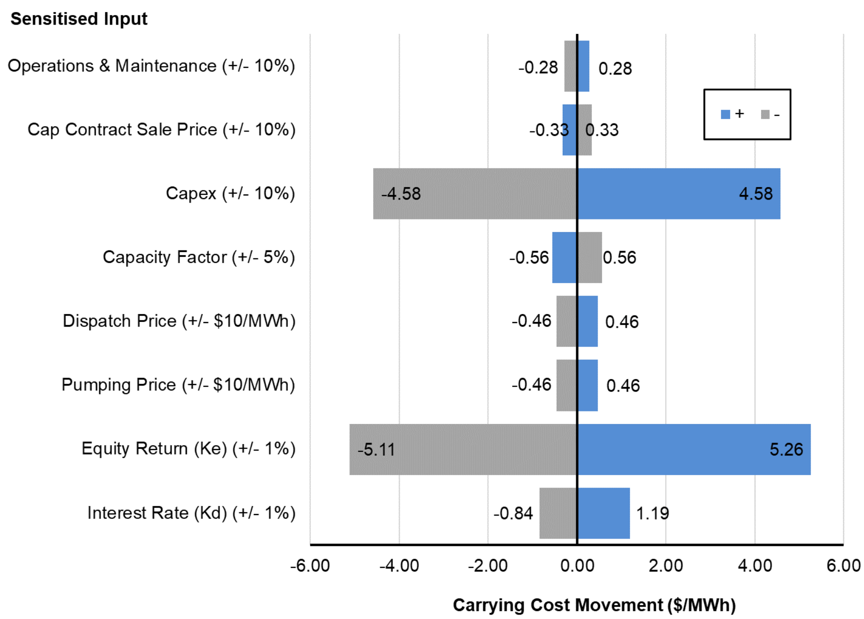
[30] For Balance Sheet Financings, Funds From Operations over Interest, and Net Debt to EBITDA respectively. For Project Financings, Debt Service Cover Ratio and Loan Life Cover Ratio.

$$p^{i\varepsilon} = \frac{X_0^i}{\sum_{j=1}^{N}(1-\tau_c).P^{\varepsilon}.\pi_j^R.(1+K_e)^{-(j)}} + \frac{\sum_{j=1}^{N}\left((1-\tau_c).\vartheta_j^i+(1-\tau_c).FOM_j^i+(1-\tau_c).\left(I_j^i\right)+P_j^i-\tau_c.d_j^i-\tau_c L_{j-1}^i).(1+K_e)^{-(j)}\right)}{\sum_{j=1}^{N}(1-\tau_c).q_j^i.\pi_j^R.(1+K_e)^{-(j)}} + \frac{\sum_{j=1}^{N}x_j^i.(1+K_e)^{-(j)}+D_0^i}{\sum_{j=1}^{N}(1-\tau_c).q_j^i.\pi_j^R.(1+K_e)^{-(j)}} \qquad (18)$$

Appendix II

To ensure robustness of results, a series of input variable sensitives were run for each of the four pumped hydro scenarios. Outputs from the two most critical scenarios, viz. Fully Merchant and 3-Party Credit Wrap scenarios, are depicted in Figures A1 and A2 respectively. The impact on the overall plant carrying cost is reflected on the x axis in $/MWh.

Figure A1: Fully Merchant Sensitivities



For the fully merchant plant, capex costs and equity return hurdles emerge as the most sensitive input variables. Movements in interest rates (Kd) are notably less impactful due to the low levels of debt supported within the capital structure. Recall equity comprises >80% of the capital structure under this scenario, explaining the sensitivity to capex overruns and elevated equity return requirements.

Notably, the impact of capital cost overruns and equity returns are less material for the 3-Party Credit Wrap scenario due to the lower overall cost of capital and a decreased reliance on equity funding. The impact of varying the cost of equity and cost of debt is skewed to the upside under this scenario (i.e. plant economics benefit more from a -1% decrease in Ke/Kd than they are harmed by an equivalent increase). This is primarily due to the 'shock absorbing' nature of the 3PC consumer-wrapped revenue stream. Regulated revenues rise in line with the higher capital cost, which in turn facilitates increased bankability and allows for a greater quantum of debt financing to offset some portion of prima-facie cost increase.

Figure A2: Semi-regulated 3-Party Credit Wrap Sensitives