Contract design for storage in hybrid electricity markets

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Abstract

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Keywords **electricity markets, risk trading, project finance,renewables,energy storage**

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CONTRACT DESIGN FOR STORAGE IN HYBRID ELECTRICITY MARKETS

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ABSTRACT

Challenges to the term financing of standalone storage in energy-only electricity markets relate to the difficulty of obtaining long-tenor contracts given multiple volatile revenue streams. Government and central agency-initiated contracting and procurement of storage has garnered interest as a means of catalysing adoption and learning curve effects, particularly given the required scale and pace of the decarbonisation objective. Given the complexity of storage operations and multiple streams of value, standard contract forms are yet to emerge. While there is flexibility in the design of forward contract arrangements, flow on effects of design on incentive compatibility in dispatch, risk-trading and investment represent a critically important avenue of investigation. This article establishes six principles for government-initiated contracting and examines the incentive compatibility of storage contract designs. We find that that preferences for structural simplicity in contract design could introduce incentive incompatibility without careful consideration of the interactions between storage operations and investment.

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1. Introduction

Electricity markets around the world have experienced major shifts in supply, away from traditional thermal generation and towards variable renewable energy (VRE). The scale and pace of the supply shift is expected to accelerate in coming years with net-zero objectives now increasingly supported by regulatory and policy frameworks to encourage the investment of low-carbon resources and supporting infrastructure. Electricity storage serves as an important facilitation resource for decarbonisation and can provide multiple functions including system balancing, active power reserves and more advanced service functionality (inertia, dynamic reactive support and grid-formation) (PSERC, 2021). Storage technologies with longer durations, 8 to 100 hours, will invariably be required to support energy supply from grids with extremely high VRE penetrations (Albertus, Manser and Litzelman, 2020), building resilience at system and local levels. Importantly, a high VRE grid will experience extremities of relative abundance and shortages, meaning the importance of storage as a load-shifter is likely to rise over time in the absence of emissions-free dispatchable resources (e.g. nuclear) (Mallapragada *et al.*, 2021). More generally, the introduction of cost-effective storage at scale may challenge the long held assumption of the non-durability of electricity markets with implications for the serviceability of demand and spot pricing.

Participation models for storage in a modern electricity market range from the development of storage projects either standalone or as part of a portfolio (either co-located with VRE resources to minimise spill, near load centres to maximise transmission transfers, or behind the meter). The latter has to date received much focus, as a part of a firmed merchant renewable portfolio (see Simshauser, 2020; Flottmann, Akimov and Simshauser, 2022), hybrid resource adequacy market participation, or driven by the specificities of tax credit requirements (Joskow, 2019). Yet the former represents an important complement to intra-portfolio approaches given diversity of participant risk appetite, capital accessibility and transaction cost economies.

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At a high level, the project level financing of standalone storage bears resemblance to the securitization of other electricity generation resources, as a revenue generating asset with a long economic life capable of supporting tranched debt and equity capital. However important differences lie in reflecting the complex operating modes of storage into a commercial financing. Charge and discharge decisions contend with an array of services (frequency control, reserves etc) which are rising in value as VRE rises, and the dynamic uncertainty and non-stationarity of net loads and hence spot prices. Above all, unlike other generating technologies the real value of storage is its flexible, multi-service capability (colloquially referred to as 'value stacking') enabling the simultaneous or sequential participation in multiple ancillary service markets as well as the arbitrage in spot electricity markets. For storage assets to date, these ancillary services markets have made up a majority of asset revenues. At the same time, ancillary service markets are frequently small and illiquid. While they are expected to expand in volume over time, they are also ultimately subject to a form of saturation risk (Pollitt and Anaya, 2021). There are also services that storage could provide but would not be compensated for because markets are missing (Newbery, 2016) or have been telegraphed but do not yet exist (Elshurafa, 2020). These include system restart services, inertial response, dynamic voltage support and system strength, avoidance of thermal generation unit starts, faster frequency markets, and potential reduction in emissions [3]. Many of these have a complex common pool resource characterization making the development of markets non-trivial (Billimoria, Mancarella and Poudineh, 2022). The manifestly random nature, skewness and variability of spot revenue streams from such markets makes it challenging to secure long-tenor financing (Joskow, 2006; Finon, 2008; Nelson and Simshauser, 2013) . The uncertain form of cashflows therefore in practice limit participation to more risk-tolerant investors, or as a form of vertical integration (i.e. those firms with offsetting portfolio level exposures to these ancillary service markets, such as energy retailers and merchant VRE generators).

If there was confidence that the market would deliver the welfare optimising level of storage, no more need to be said of the matter. But the typical merchant utility is unlikely to be able to provide the level of strategic storage reserves required of risk averse governments – firms can usually tolerate PoE10 risks. However given market incompleteness (Mays *et al.*, 2022) whether they can invest in PoE5 assets and above, which may well be necessary in a high VRE grid, is an open question. Going forward, we believe PoE5 investments will be important and therefore broader participation modes (i.e. merchant and government-initiated) may be important given the scale and timeline of deployment required to achieve decarbonization objectives.

Even in risky energy only markets such as Australia's NEM, traditionally, a sufficient level of cashflow certainty has been facilitated via vertical integration (Simshauser, 2021) or risk-trading between market counterparties with the canonical contractual forms well established for legacy thermal (Deng and Oren, 2006) as well as renewable generation (Savelli *et al.*, 2022; Newbery, 2023). However the design of such derivative arrangements through which a sufficient level of cashflow certainty is provided for storage projects of varying durations remains open, from our review of the literature (as set out below).

Given the political economy of electricity supply and any decarbonisation gap that may exist vis-à-vis government preferences (cf. energy-only markets and market-driven efforts to decarbonise), in practice an increasing role of governments and central agencies incentivising storage resource deployment and operations is predictable. In some jurisdictions, this involvement comes in the form of capacity markets or other resource adequacy overlays (Mays *et al.*, 2022), tax credits, grants and funding subsidies (Jenkins *et al.*, 2022), while in others this has involved central initiation of Contacts-for-Differences

[3] Though we note the contribution of storage to emissions reduction is complex and non-linear given that avoided emissions can vary based on the characterisation of the marginal price setter, and the trade-offs between revenue maximisation and emissions reduction (Arciniegas and Hittinger, 2018).

(CfDs)[4] – standalone or as part of a co-ordinated initiative with renewable and network investment, and/or direct investment (Simshauser, Billimoria and Rogers, 2022).

One stream of the literature argues caution or 'judicious use' due to the risk of distortionary impacts of such intervention on the proper functioning of markets (see Hogan, 2005, 2022, and Simshauser, 2019 respectively). Another line suggests this is a complementary form of 'hybrid market' (Roques & Finon, 2017; Joskow, 2022) given public reliability externalities (Joskow and Tirole, 2007; Wolak, 2022) and distortions in existing capacity markets (Mays, Morton and O'Neill, 2019). This article does not seek to directly argue its merits, but it is reasonable to assume its presence particularly given rapid centrally agreed objectives for decarbonizing electricity systems.

Yet in the context of these rapid timelines (and at the time of writing a global energy crisis) the design of government participation may directly affect the balance of the so-called energy trilemma. More specifically, given emissions abatement represents a near-term imperative, it is the effects of such actions on consumer costs and system reliability that are also relevant. Thus the research question that is the focus of this article is how should **government-initiated** risk-hedging contracts be structured to support long-tenor financing for stand-alone energy storage, to **avoid distortions** and **preserve incentive compatibility,** given dynamic price **risks**? The scope is focused on market without resources adequacy mechanisms (such as capacity auctions) but given questions on the latter's suitability to low-carbon systems (Shu and Mays, 2022), this analysis may have broader relevance.

To address this question, we offer a combined qualitative and quantitative assessment of storage contract design in a central context, specifically (i) we enunciate a set of principles for government participation in storage markets (ii) we review the literature and provide a taxonomy of standardized contract forms for energy storage (iii) we quantitatively assess the incentive compatibility of such forms a under a modelling framework that combines a short-run operational model with a long-run investment and financing model and (iv) propose a novel 'yardstick' contract for energy storage that allows for minimum levels of cashflow stability but preserves incentive compatibility for operational dispatch. Our findings offer insights to policy makers for designing and structuring long-term contracts for energy storage, and risk mitigating measures.

The rest of this article is organized as follows. Section 2 reviews the state of the art of risk trading and contract design for energy storage and elucidates a set of principles for central-agency contracts. Section 3 sets out the methodology for assessing contract design over short- and long-run horizons. Section 4 applies our methodology to a case study of storage in the South Australian region of Australia's National Electricity Market. Policy implications are set out in Section 0, and conclusions follow.

2. Review of the state of the art

2.1. Contract design for electricity storage

In a classic energy-only market design, resource adequacy depends upon the decentralised investment decisions of market participants. Given differing degrees of participant risk aversion, trading and contracting between participants, either bilaterally or multi-laterally supports efficient risk transfer (de Maere d'Aertrycke, Ehrenmann and Smeers, 2017; Abada

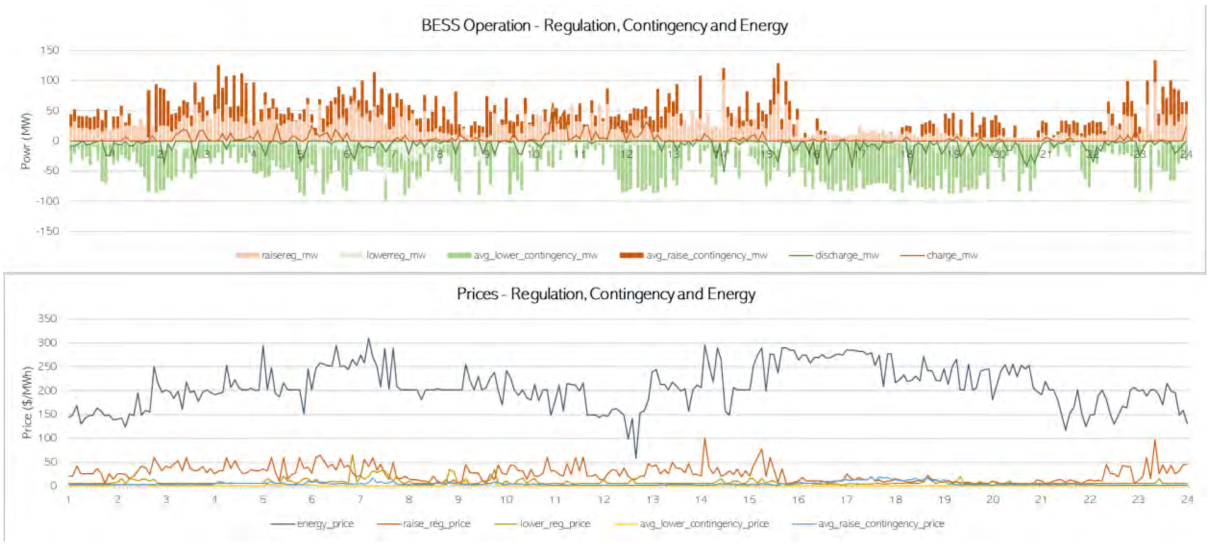
[4] Examples include (1) scaled tenders for long-duration storage potentially coordinated with renewable procurement and transmission augmentation (Australian Renewable Energy Zone auctions, grid scale storage tenders in India), (2) smaller scale storage contracting targeted towards specific grid locations or services – contracting in the US, UK and Australia, (3) regulatory storage targets in California and (4) storage investment delegated to state-owned generation companies (Australia).

et al., 2019; Mays *et al.*, 2022). Maintaining deep, liquid and adaptive markets for risk-trading can mitigate the degree of incompleteness and is central to supporting resource adequacy. Even in markets where generators and retailers have vertically re-integrated, risk trading and contracting remains important to portfolio risk management and system reliability (Simshauser, 2021).

To manage the risks associated with segregated generation and demand (not restricted to retail), including specifically the positive skewness associated with electricity prices, a suite of contracting and hedging products evolved with a range of thermal technologies in mind (Deng and Oren, 2006). Base and peak futures contracts tended to suit base and intermediate load generators, while options or ‘cap’ contracts are generally linked to flexible peaking units. Variants included peak/off-peak instruments supporting generation more actively dispatched at particular times of the day, and a range of fuel-linked instruments, including heat-rate and spark spread contracts. In a modern portfolio context, the optionality embedded in a multi-layered / multi-product approach to risk management yields significant benefits (Deng and Oren, 2006; Homayoun *et al.*, 2015). Nevertheless, the risk differential between financial contract and retail risk exposure has led, in many liberalized markets, to a preference for physical hedging and vertical integration – for example supporting up to 75% of peaking plant in the NEM (Simshauser, 2021).

The multi-dimensional nature of battery storage complicates the design of an optimal contract. Where generation is uni-directional, storage operations require the management of bi-directional energy flows (charge and discharge). Moreover, the importance of ancillary service revenues to storage commercial viability means that arbitrage must reflect not just inter-temporal but multi-market opportunity cost (Gilmore, Nolan and Simshauser, 2022). As an example, the actual dispatch of an existing storage facility in the NEM across its nine energy and frequency control ancillary service (FCAS) markets over a given day is provided in Figure 1. Fig.1 illustrates the dynamic and multi-faceted nature of storage operations. This multi-dimensionality is recognized for its capability in boosting profits and reducing risk in a multi-resource portfolio (Bitar *et al.*, 2011; Flottmann, Akimov and Simshauser, 2022).

Figure 1: Intraday dispatch of storage facility in the NEM

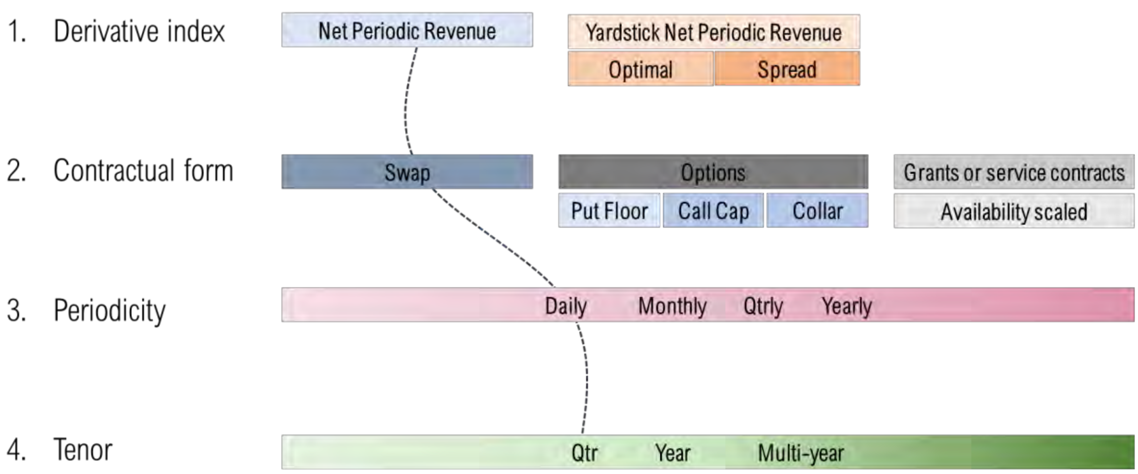


Source: AEMO

A structural categorization of contracts for standalone storage, based on our review of the literature, is provided in Figure 2 below. While contracts themselves can be highly granular, four specifications provide the logic for classifying contracts with respect to the inherent financial exposures, as follows:

(i) the derivative index (if any in the contract) – which for storage generally focus upon net spot revenues generated by the unit, or a proxy/yardstick thereof. Not all contracts are structured as a cash-flow exchange. For example, availability payments, grants or other quasi-fixed payment contracts provide a uni-directional and incremental stream of cashflows to the project. Certain forms have also extended to a 'spread' concept based on periodic averaged price differentials (Renewable Energy Hub, 2020).
(ii) the contractual form – which at a high level can include a swap of cashflows (predominantly a fixed stream for a floating stream) (Gabrielli, Hilsheimer and Sansavini, 2022) or an option to swap based upon specific triggers and asymmetry (call, put or collar options) (McConnell, Forcey and Sandiford, 2015; Baxter, 2019; AEMO Services, 2022).
(iii) the periodicity of the contract – for example, whether the cashflow exchange applies on a dispatch interval (DI) basis, or averaged or summated over longer periods. Where many generation contracts apply on a DI-to-DI basis, storage behaviour can vary across time intervals. Therefore some form of summation or average of the index flows tends to apply.
(iv) the tenor of the contract (how long the contract is on foot) – i.e. monthly, quarterly, or yearly. Generally exchange traded contracts have to date had maximum tenors of single years, while bilateral and negotiated contracts tend to be structured over a longer periods (i.e. 7 to 15 years) to underwrite project financings.

Figure 2: Structural categorization of storage contracts



In discussing risk trading for standalone storage the literature is segregated based on the operating paradigm of storage facilities in electricity markets. Under a purely competitive or market-based operational paradigm, tolling contracts have been discussed (Anaya and Pollitt, 2015; Gabrielli, Hilsheimer and Sansavini, 2022) and may include the exchange of operational trading rights (Baxter *et al.*, 2018). The latter is further enabled by the virtualization of storage capacity via unit partitioning (Gantz, Amin and Giacomoni, 2014).

Under the framework of regulated storage operations, a set of works introduce the concept of *financial storage rights* as a corollary to *financial transmission rights* that treats energy storage as a communal asset scheduled by a central system operator (Munoz-Alvarez and Bitar, 2014; Taylor, 2015; Brijs *et al.*, 2016; Muñoz-Álvarez and Bitar, 2017; Thomas *et al.*, 2020). Central control of storage retains incentive compatibility though only proven heretofore in the absence of uncertainty (Jiang and Sioshansi, 2023). While termed differently, both competitive exchanges of trading rights and regulated storage have the financial characteristics of revenue swap style arrangements, where the purchaser receives entitlements to the inter-temporal arbitrage gains that storage generates, and the investor receives fixed payments. Given shorter-timeframes, Aguiar and Gupta (2021) propose an insurance contract between storage and a renewable producer to address the problem of imbalance shortfall allocation in two-settlement markets.

The hybridization of the energy market however increasingly involves central agencies in facilitation, via financing or a direct counterparty role, in storage financing and investment – generally in partnership with private companies. In certain situations, consideration for the financial support provided by the central agency has included the provision of additional system services including inertia, fast-frequency response, system integrity, voltage support, system strength and grid formation. (Csereklyei, Kallies and Diaz Valdivia, 2021). Based on market design, this has led to segmentation of financial value as between regulatory and market revenue streams, with a flow onto capital structure (Johan *et al.*, 2021).[5]

In the context of a hybrid market Mountain *et al.* (2022) propose a mandatory storage certificate scheme (similar to mandatory obligations for renewable energy) where retailers are obligated to procure storage based on projections of storage requirements by the central planner. This framework envisions the execution of availability-style contracts between projects and obligors to purchase certificates – which would support an incremental storage revenue stream.

2.2. Principles for government initiated contracting of electricity resources

The rational for a hybrid model is well stated in Roques and Finon (2017), Joskow (2022) and Keppler, Quemin and Saguan (2022). They all articulate a hybridisation of the market that combines 'competition in the market' with Demsetzian 'competition for the market'.

ñ é these developments replace the reliance on short-term wholesale prices and voluntary market driven hedging contracts of limited duration to bring forth the targeted quantities and types of wind and solar generating capacity and storage to meet decarbonization commitments with competitive procurement of zero-carbon energy and storage.ò (Joskow, 2022, p325)

Yet this has a concomitant acknowledgement that such decision making is, by definition, interventionist and can adversely impact the proper functioning of the market and energy system. Conversely, if incomplete markets dictate that the alternative fails, what principles might govern how such contracts should be designed to minimise or 'bound' any perceived distortions, given the political economy of electricity supply? Below we set out six principles for government-initiated CfDs generalized to the procurement of generation or storage resources (though our focus is on the latter). These principles are additional to standard contracting principles relating to the allocation and bearing of risk. We have aimed for a degree of generality in that such principles should apply to large-scale transactions, auctions and tenders as well as smaller-scale, more bespoke contracting initiatives.

1. Preservation of incentive compatibility in the wholesale market. The first principle is that the design of contracts should ensure that market participants retain sufficient incentives for optimal participation in wholesale spot market – central to the operational reliability and security of the grid (Newbery, 2023). This includes the preservation of locational and temporal signals in the short term market, including for energy, reserves, and ancillary services (such as and frequency control).
2. Ensure the proper functioning of forward derivative markets by limiting distortions to short, medium and long term contracting and hedging. The key issue here is to recognize that by providing a project hedge or incremental revenue source, central

[5] In certain markets, particularly in the US, an important component lies in resource adequacy or capacity value, for markets that run separate auctions for capacity. In such markets, the accreditation of storage remains an important area of focus, and conflict. This however is outside of our scope of our paper.

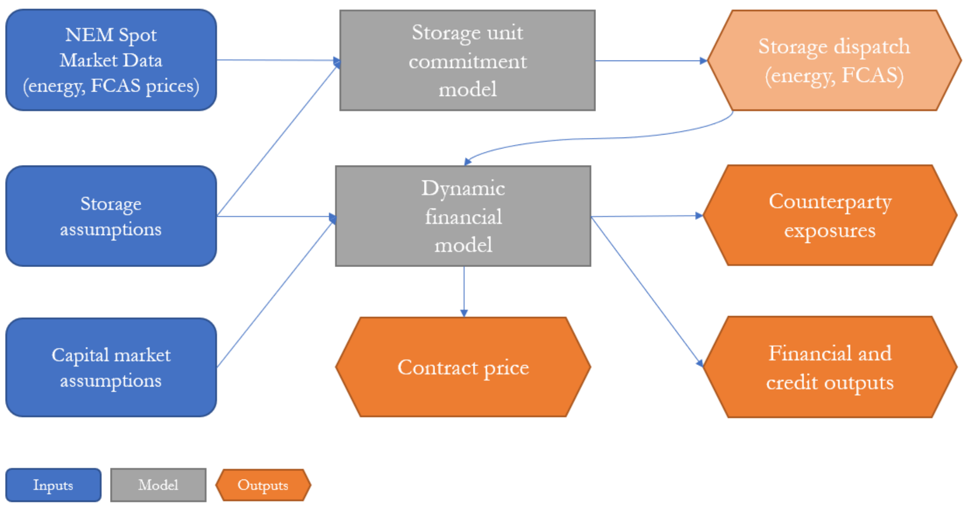
agencies inevitably affect project risk balance (Simshauser, 2019; Nelson, Nolan and Gilmore, 2022). Consideration should also be given to contract availability, liquidity and pricing in risk-trading markets, and downstream retail incentives.
3. Relatedly the risk of distortion to long-term investment signals requires careful consideration, given explicit or implicit biases in contract form (Mays, Morton and O'Neill, 2019; Shu and Mays, 2022).
4. The political economy of central agency contracting also requires a focus on potential moral hazards and equity impacts of decision-making, particular where there is risk of socialisation of losses and privatisation of profits.
5. Avoiding adverse impacts on reliability and security of the system. This principle has strong links to (1) but extends further to the operational dispatch and control of systems of storage. Thus contracts should extend to consideration and transparency of dispatch participation and operational control to limit security risks. Notably some recent contracts have addressed 'missing markets' for security including inertia and grid-formation (Johan *et al.*, 2021).
6. Finally efficient procurement and value for money vis-à-vis cost imposts on the market, and upon consumers given 'benevolent planner' central functionality (Simshauser, Billimoria and Rogers, 2022). To this end, alignment with access and connections, and with the ability of counter parties to execute is important.

3. Methodology

This section presents a formulation for modelling the impact of contract design upon short-term and long-term participant incentives. The analysis focuses on the tractability of stand-alone storage investments under an array of market conditions and business cycles spanning a 10-year window.

The task of simulating these business combinations requires the integration of multiple data sources and a suite of operational and financial simulation models which traverse operational and planning horizons. The flows of data inputs to models and outputs is show in Figure 3.

Figure 3: Data sources and modelling framework



The methodology integrates two central models – (i) the Storage unit commitment model, which models storage commitment and dispatch decisions given a suite of market and technical inputs, and (ii) the Dynamic financial model – which integrates outputs from the unit commitment along with technical and capital assumptions to construct project financing and capital structures, producing financial and credit outputs along with the minimum viable contract price. The models are coded on Julia 1.5.3 using JuMP 1.4.0 and solved using Gurobi solver 9.5.0 (Gurobi Optimization LLC, 2020).

3.1. Storage unit commitment model

We consider a storage unit trading in a decentralized electricity market. The market setting under consideration does not include a day-ahead market and relies on the real-time market (RTM) for the spot trading of energy and reserves, settled on the basis of marginal pricing. To simplify the analysis we assume all agents are price takers who do not act strategically, and agents self-commit into multiple energy and reserve markets based on imperfect foresight of exogenous prices.

Let $t \in T$ be the ordered set of half-hourly trading intervals over a period T (for example a quarter). For each trading interval we denote the locational marginal price of energy as λ_t^e and the marginal price for upward reserves as λ_t^{R+}, and downward reserves as λ_t^{R-}. However, in the presence of forecast uncertainty the energy price perceived by the storage unit will be the sum of the actual price and ε_t^e, a random variable representing the price forecast error $\hat{\lambda}_t^e = \lambda_t^e + \varepsilon_t^e$ (and similarly for reserves) (Xu, Korpas and Botterud, 2020). For simplicity in illustration, we have only shown singular upward and downward reserve markets (though the modelling framework extends to multiple reserve markets, including frequency regulation and frequency contingency – see Appendix A). To model storage unit operations we denote power charge p_t^C, power discharge p_t^D, and reserve (upward/downward) as p_t^{R+}/p_t^{R-}. We construct the matrix of prices $\boldsymbol{\lambda} = [\lambda_1^e \dots \lambda_T^e;\ \lambda_1^{R+} \dots \lambda_T^{R+}; \lambda_1^{R-} \dots \lambda_T^{R-}]$ as similarly for energy and reserves dispatch $\mathbf{p} = [p_1^C \dots p_T^C;\ p_1^D \dots p_T^D; p_1^{R+} \dots p_T^{R+}; p_1^{R-} \dots p_T^{R-}]$. In each trading interval, the spot market surplus perceived by the storage unit $\Phi_{s,t}$ is set out below.

$$\Phi_{s,t} = \hat{\lambda}_t^e(p_t^D - p_t^C) + \hat{\lambda}_t^{R+}p_t^{R+} + \hat{\lambda}_t^{R-}p_t^{R-} + k^+\hat{\lambda}_t^e p_t^{R+} - k^-\hat{\lambda}_t^e p_t^{R-} - c^d(p_t^D + p_t^C + k^+p_t^{R+} + k^-p_t^{R-}) \qquad (1)$$

Over a time period T the total spot market surplus is the sum of the surplus over each trading interval $\Phi_s = \sum_{t\epsilon T} \Phi_{s,t}$.

The first three terms comprise the sum of net revenues from energy charge, discharge and reserve. The fourth and fifth terms represent incremental revenues or costs associated with reserve actuation (e.g. regulation services) (Gilmore, Nolan and Simshauser, 2022) with k representing an estimate of the reserve utilization (in other markets known as mileage) during the dispatch period. In some markets, these costs receive incremental utilisation payments, but we have excluded these to remain consistent with current NEM market design.

Degradation represents an important aspect of BESS technical parameters and operation. Inevitable cell degradation renders the battery lifetime volatile and highly dependent on battery dispatch, and thus incurs an opportunity cost during operations. We incorporate a marginal cost of degradation c^d that is imposed on the summated charge and discharge of the unit, including utilization during reserves as a proxy for degradation from unit cycling in line with Xu, Korpas and Botterud (2020); and He *et al.* (2021) as per the final term of the objective function.

Technical constraints also apply to a storage unit, assuming symmetric charge and discharge power capacity of P^R. Power limits restrict the delivery of reserve and charge/discharge in (2) and (3). While the constraints here are shown for a single reserve market for ease of illustration, our case study incorporates the eight available frequency control ancillary reserve markets in the NEM. This requires additional granularity in the specification of reserve and energy delivery co-optimization constraints. For contingency reserve markets, based on market ancillary service specifications (AEMO, 2022b), storage is able participate in multiple contingency reserve markets at once subject to state-of-charge. However the delivery of regulation FCAS is assumed as mutually exclusive with the delivery of contingency reserves. The granular constraints underpinning this are set out in Appendix A. The state of charge of a unit at each trading interval S_t is defined in (4) reflecting charge and discharge efficiencies, q^C and q^D and the utilization of battery capacity during reserve provision. Finally limits on the state of charge are defined in (5) based on the energy duration d.

$$p_t^D - p_t^C + p_t^{R+} \leq P^R \qquad \forall\, t \in T \quad (2)$$

$$P^R + p_t^D - p_t^C \leq p_t^{R-} \qquad \forall\, t \in T \quad (3)$$

$$S_t = S_{t-1} + q^C p_t^C - p_t^D / q^D \qquad \forall\, t \in T \quad (4)$$

$$S_t \leq dP^R \qquad \forall\, t \in T \quad (5)$$

A storage unit will seek to maximise its short run surplus based on estimates of exogenous prices. This results in a tractable LP which can be solved to optimality by commercial solvers (Gurobi Optimization LLC, 2020).

$$\max_V \Phi_s \quad s.t. (1) - (5), \{V := (p_t^D, p_t^C, p_t^{R+}, p_t^{R-}, S_t)\} \quad (6)$$

3.2. Contract formulations

In the formulation of contracts, we define Φ_c as the contract difference payment, the sum of net proceeds from contracts based on the payoff rules of the contract. It is assumed that contracts are executed ahead of the relevant dispatch period, and as such volumes and payoff rules are fixed. Our battery is assumed to be perfectly available and consequently the combination of spot revenues and difference payments made under swaps and options in the model under perfect foresight always produce a net surplus. For the purposes of elucidating central design principles it suffices to adopt a degree in generality in contract form specification, though recognizing the granularity of real-world contract negotiation.

Revenue swaps are referenced against the aggregate spot revenues of the storage unit, swapped against a fixed payment ϕ.[6]

$$\varphi_T = \sum_{t \in T} \lambda_t^e (p_t^D - p_t^C) + \lambda_t^{R+} p_t^{R+} + \lambda_t^{R-} p_t^{R-} + k^+ \hat{\lambda}_t^e p_t^{R+} - k^- \hat{\lambda}_t^e p_t^{R-} \quad (7)$$

$$\Phi_c = v(\phi - \varphi_T) \quad (8)$$

Periodic revenue floor and caps instruments are intended to set downside and upside limits on storage net revenues over a period T. They are hence structured as call and put options on storage net revenues in (9) and (10) respectively, where η represents the threshold payment level above or below which the options are exercised. The premium paid or received for the option is ϕ. A zero-cost collar can be created by combining the floor and cap instruments in a manner such that the option premia offset each other, resulting in storage project financing with upside and downside bounded revenues.

$$\Phi_c = v(-\phi + \max(\eta - \varphi_T, 0) \quad (9) \qquad \Phi_c = v(\phi + \min(\eta - \varphi_T, 0) \quad (10)$$

For the net revenue swaps and options defined above the derivative contracts are referenced against actual net spot revenues $\varphi_T(\boldsymbol{\lambda}, \mathbf{p})$. We also define a set of yardstick contracts for a storage unit, which are based on the revenue swap formulation in (8) but

[6] In this formulation of a revenue swap, for simplicity, we have included revenues associated with the utilization of reserves in the floating component of the difference payment, as such utilization would be captured by metering of energy injections or withdrawals. Our testing against an alternative formulation which excluded such revenues did not alter the central findings.

settled against a optimal spot surplus $\varphi_T(\boldsymbol{\lambda}, \mathbf{p}^*)$, where we replace variables for actual dispatch $\mathbf{p}$ with parameters based on optimal values $\mathbf{p}^*$ as the outcome of a short-run surplus maximization with a zero price forecast error ($\varepsilon_t^e = 0$). In essence we are substituting the contract index from actual spot revenues received by the unit, with yardstick spot revenues as determined by an optimal 'ex-post' analysis.

Finally grants or service contracts represent a one-way revenue stream to the storage facility, scaled by the average availability of the unit α.

$$\Phi_c = \alpha\eta \qquad (12)$$

3.3. Dynamic financial model

The dynamic financial model considers the impact of contract structure on the market financing of a stand-alone storage resource. In particular, we are interested in understanding the minimum viable price that can be offered on a particular form of contract in a manner that secures a commercial financing of the asset while reflecting the risk and return preferences of capital investors. The model takes as inputs the results for the Storage unit commitment model combined with storage technical assumptions and capital markets input data to produce a comprehensive set of financial structures, credit metrics, buy-side counterparty exposures and minimum contract price. Given the role of credit quality as a fundamental driver of investment in energy-only markets, both across independent (Gohdes, Simshauser and Wilson, 2022) and vertically integrated operations, (Simshauser, 2021) it is important that the model mimics practical tranched capital structures and corresponding finance-ability metrics in a manner that reflects observed behaviours vis-à-vis capital structures. The model develops a cashflow waterfall based on metrics that are consistent with generally accepted financial conventions used by project finance banks. These metrics are subject to robust constraints over the financing period reflecting the requirements of debt and equity capital. The core formulation is set out below along with definitions of financial metrics. The objective function of the model is defined as a minimization of the contract price ϕ subject to the financial constraints. Cashflows and financial metrics are subscripted by q and y to represent cumulative cashflows over a quarterly and annual period. This results in a tractable LP problem that is solved to optimality.

$$\min_W \phi\,, s.t. \{W \coloneqq (\phi, D, E)\} \quad (13)$$

$$\Pi_q^{CFADS} \geq DSCR_{min}\,\sigma_q \qquad (14)$$

$$\textstyle\sum_{q\in Q} \Pi_q^{CFADS} \geq DSCR_{ave} \sum_{q\in Q} \sigma_q \qquad (15)$$

$$\Pi_q^{CFE} \geq CFE_{min}\,E \qquad (16)$$

$$\textstyle\sum_{q\in Q} \Pi_q^{CFE} \geq CFE_{ave}\,.\,|Q|.\,E \qquad (17)$$

Equation (14) ensures that cashflows available for debt service (CFADS) exceed a scaled quantity of forecast debt service – akin to minimum debt service coverage ratios (DSCR) covenants as a key project financing metric. Equation (15) ensures that the average DSCR is in excess of a required threshold. Equation (16) ensures that quarterly cashflows available to equity (CFE) exceed a minimum requirement guided by investor preferences for periodic cashflow yield, while equation (17) ensures that equity return thresholds are met in expectation over the investment horizon.

$$\Pi_q^{EBITDA} = \Phi_c + \Phi_s - c^f P^R \quad (18) \qquad \Pi_q^{CFADS} = \Pi_q^{EBITDA} - \Gamma_q \qquad (19)$$

$$\Pi_q^{CFE} = \Pi_q^{CFADS} - D.\rho \quad (20)$$

Constraints (18) to (20) define key financial flows in the cashflow waterfall. Earnings before Interest, Taxation, Depreciation and Amortization (EBITDA) Π_q^{EBITDA} is defined as the sum of spot market surplus and contract difference payments, minus fixed operating costs. In (18) CFADS $\Pi_q^{CFADS}$is defined as EBITDA minus taxation liabilities Γ, while CFE Π_q^{CFE} (19) sets out cashflows accessible to equity investors after accounting for fixed debt service payments, represented as the product of total debt and the annuity payment factor given the debt horizon and interest rate as set out in (20).

Taxation liabilities are calculated as a multiple of tax rate and EBITDA minus quarterly depreciation d_q with the depreciation schedule based on a flat rate on invested capital over the tax life of the asset.

$$\Gamma_q = \tau(\Pi_q^{EBITDA} - d_q - i_q) \qquad (21)$$

Debt service payments are based on standard annuity mortgage repayment profiles.

$$\rho = r/1 - (1+r)^{-|Q|} \; (22) \qquad\qquad i_q = \rho - p_q \qquad (23)$$

Constraint (24) ensures total invested capital is equivalent to the sum of debt D and equity E tranches.

$$c^I P^R = D + E \qquad (24)$$

We also undertake analysis of parameter changes on capital returns given a fixed contract price. In such exercises, the contract price ϕ is is set as a fixed parameter rather than a decision variable and the objective function is defined as a maximisation of equity returns, defined as total distributions over equity capital invested, replacing the previous objective function (13) by the objective function (25) and constraint (26). This results in a non-convex bilinear problem – which can be solved to global optimality by the Gurobi commercial solver under acceptable timeframes for the cases considered (Gurobi Optimization LLC, 2020).

$$\min \textstyle\sum_{q\in Q} \Pi_q^{CFE} . E^{-1} \quad (25) \qquad E.E^{-1} = 1 \qquad (26)$$

Finally we describe the buy-side counterparty risk exposures $\Phi_O = -\Phi_c$ as the negative of the contract difference payments generated by the resource (as the counterparty to contractual cashflows).

4. Case study

4.1. Data sources and assumptions

The case study for this article uses historic, granular 30-minute spot pricing data from the NEM's South Australian region (AEMO, 2022c). The period selected from financial year (FY) 2012-13 to FY2021-22 represents multiple NEM pricing cycles and thus produces rich insights into the economics of storage capacity in an energy-only market setting with a high market price cap of AUD $15,500/MWh and low market price floor of -$1000/MWh. In addition, the selection of the South Australian region is particularly apt as an area of extremely high renewable deployment (i.e. 60+% VRE market share), both at a grid scale and consumer level, often resulting in notable price volatility (thus perhaps not just fortuitous that the region was selected as the site of the NEM's first utility-scale, 100MW / 129MWh battery in 2017). Moreover, as South Australia is often colloquially referred to as the 'canary in the coalmine' for VRE integration (Nelson and Orton, 2016). While this may offer insights for other regions that are not as yet advanced in the scale of intermittent, zero-marginal cost resources, we caveat that any extrapolation should consider the comparability of market design, industrial organization and regulation. The model co-optimizes and self-schedules dispatch based on energy price traces of the NEM's South Australia regional reference price (SA1 RRP), and eight frequency control ancillary service markets (upwards and downwards regulation service, six contingency services – with 6 second, 60 second and 5 minute duration, each in upwards and downwards directions).

We model eight storage facilities in total across a range of durations with technical assumptions set out below in Table 1. Capital investment costs are sourced from AEMO (2022a) based on the assumptions for the South Australia Low cost region, with investment costs for BESS units with durations of 12 and 16 hour extrapolated based on a DC-energy capital cost of \$216/kWh (primarily the battery cell, cabinet, racking etc) and an AC-power capital cost of \$290/kW (including inverter, balance-of-plant, land, permitting, development costs etc) (Lazard, 2021).

In all cases, power capacity sizing's are based off an assumed capital investment amount of \$200 million, providing unit sizing's consistent with our base price-taker assumption. Fixed costs are sourced from (AEMO, 2022a) with economic and tax lives of 25 and 20 years assumed for all assets. Degradation cost of \$7/MWh throughput for all BESS consistent with the lower end of the \$7-15/MWh range provided by He *et al* (2021), given the assumed new vintage of the assets. All assets also incur a transmission access charge of \$4500/MW-yr (Simshauser, Billimoria and Rogers, 2022). Charge and discharge efficiencies for BESS are based on the Li-ion design adopted in He *et al.* (2021) and AEMO (2022a) for pumped hydro. Energy utilization is assumed to 0.2 for regulation raise services, 0.1 for regulation lower services and zero for contingency services (Gilmore, Nolan and Simshauser, 2022).

Table 1: Storage technical assumptions

#	Tech	Pmax (MW)	Duration (hrs)	c^I (\$/kW)	c^I (\$/kWh)	c^f (\$/kW/yr)	q^d/ q^c (%)	c^d (\$/kWh)
1	BESS	245	1	818	818	7	0.86	7
2	BESS	182	2	1097	549	11	0.86	7
3	BESS	115	4	1746	437	17	0.86	7
4	BESS	65	8	3077	385	28	0.86	7
5	BESS	50	12	4035	336	33	0.86	7
6	BESS	38	16	5235	327	33	0.86	7
7	PH	59	8	3412	427	17	0.70	0
8	PH	34	24	5905	246	17	0.70	0

In addition, a range of economic, financial and capital markets assumptions underpin capital sizing and structuring in the Dynamic financial model as per Table 2. Debt and equity sizing constraints are assumed to apply quarterly and contract payments are settled at the same periodicity. Our financial assumptions are consistent with Gohdes, Simshauser and Wilson (2022) and updated based on most recent market data .

Table 2: Economic and financial assumptions

Assumption	Value
Risk free rate	3.5%
Debt margin	1.0%
Equity risk premium (post-tax)	4.5%
Tax rate	25%
Debt tranche	Standard credit foncier
Tenor	10 year
Debt amortization	20 years

Min DSCR–- qtrly	1.05
Average DSCR	1.30
Min quarterly equity return	0.0

The model is calibrated through a comparison of template unit assumptions with public data on recently approved and constructed projects across the NEM and the US and with (Ramasamy *et al.*, 2021), as well comparing consistency of the assumed toll/fixed payment requirements with the most recent Lazard Levelized Cost of Storage study (Lazard, 2021).

4.2. Results

The modelling illuminates particular considerations in central structuring and procurement of contracts for storage. Key insights are provided in the following order of subsections below relating to (i) the importance of aligning trading rights, operational co-ordination and investment interests under toll/swap style contracts (ii) asymmetries associated with revenue cap and floor arrangements, and (iii) results from the specification of a ‘yardstick’ contract design for storage that maintains cashflow stability but aligns operational incentives.

4.2.1. The interactions between storage operations, trading rights and offtake

First, the financing of storage facilities are modelled on the basis of a revenue swap for the full exchange ($v = 1$) of spot cashflows under perfect foresight and perfect availability in return for a fixed quarterly payment. Results for the base case are shown in Table 3. It is observed that the swap enables the project to receive fixed cashflows thereby enabling long-tenor leveraged financing. Moreover, given current and historical levels of volatility observed in the NEM, the fair value (or expectation) associated with floating cashflows exceeds the fixed payment supporting the notion of a risk aversion discount for projects and equity in particular.

As an aside, it is noted that the relative differential between the fixed payment and fair value narrows with higher storage durations. While this suggests the capital and operational costs associated with longer duration storage may not have necessarily enabled better value capture under past price patterns (in part due to the relative proportion of FCAS revenues), we caution extension of this notion beyond the historical period of reference in this study.

Table 3: Base Case outcomes for Revenue Swap

	1 BESS	**2 BESS**	**3 BESS**	**4 BESS**	**5 BESS**	**6 BESS**	**7 PH**	**8 PH**
Fixed payment, annualized $m	22.7	22.8	22.2	21.3	20.7	20.1	19.1	18.6
Fixed payment, as % of c^I	11.4	11.4	11.1	10.6	10.3	10.1	9.5	9.3
Gearing, %	80.3	80.3	80.3	80.3	80.3	80.3	80.3	80.3
Fair value (mean), $m	157.9	126.1	84.3	50.4	39.1	30.3	44.1	26.1
Floating val median, $m	139.2	110.0	71.1	41.4	31.9	24.7	35.7	21.0

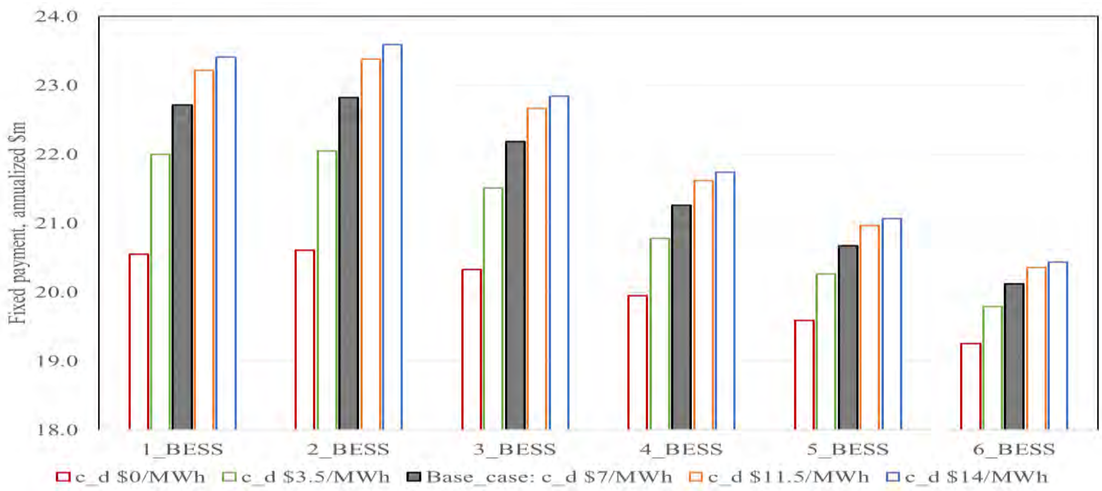
Floating val P25, $m	179.8	147.6	100.9	59.5	46.6	36.7	53.8	32.4
Floating val P75, $m	41.9	33.2	22.6	13.6	10.6	8.3	11.4	6.8
FCAS as % of total revenue	45.7	44.3	43.1	42.1	41.7	41.4	43.4	42.5

It is notable that this contract structure shifts predominantly all financial risks associated with operating the perfectly available asset from seller to the buyer. As such, the asset owner received a fixed annuity but has limited ongoing financial incentives for optimal operation of the storage resource from the perspective of maximising spot market value (we prove this for a simplified case in Appendix B). This represents a fundamental misalignment of interests with regards to short term dispatch and market participation. For central agency contracting, this represents a direct concern in relation to maintaining incentive alignment for dispatch, maintenance and plant availability. Reliability outcomes could also be affected by weak incentives for storage to participate in dispatch, especially under scarcity conditions. Two particular aspects of operational risk, degradation and forecast price error, are considered further.

Figure 4 shows the minimum fixed payments under a range of degradation cost assumptions for a singular BESS of 8 hours duration ranging from $0/MWh to $14/MWh and illustrating the impact of degradation costs on financial value, affecting minimum viable contract prices by 6-14% across durations.[7] Managing degradation thus represents an active source of value for project participants. Thus the allocation of degradation risk represents an important consideration in the project risk allocation, which bear particular noting in the context of a large scale central tender. Under a swap arrangement where spot market revenues are exchanged for a fixed payment, this aspect represents a potential misalignment of risk. Given a fixed-payment, project investors will be averse to cycling of the unit as it adversely affects degradation. If allocated this decision right will seek to limit cycling even where profitable opportunities arise in the spot market. It is common from a project perspective for such risks to be reallocated to battery OEMs through warranties with consequent restrictions on operational cycling. Management of central BESS procurement must thus consider how such risk allocation affects the operational incentives of project owners under fixed for floating type arrangements.

Figure 4: Minimum viable contractual fixed payment for 8-hr BESS under a range of degradation costs (from $0/MWh to $14/MWh)

[7] It is noted that while we illustrate the results for a particular storage unit – the patterns remain consistent for all of the storage units in the sample, except where indicated.



The alignment between the allocation of the financial risks associated with price error (incorrect prediction of prices) and the operational decision-making rights associated with price error also requires consideration. Price-taker storage operations use complex predictive algorithms to predict prices and to managing inter-temporal price and dispatch risk in the presence of forecast uncertainty. Through a fixed-for-floating swap arrangement the risks and rewards associated with multi-market, inter-temporal revenue arbitrage are transferred from the storage unit to the counterparty. This is emphasised through examining the variability of cash flows for the storage unit and buy-side counterparty.

Figure 5 considers the cashflow risk profile for a BESS unit of 8 hours duration under a merchant and fully contracted basis, and for a buy-side counterparty with no retail obligations (akin to a central agency or government). The boxplot distribution of pre-financing cashflows (CFADS) under price forecast uncertainty (as represented by the standard deviation of the price forecast error, ranging from $0/MWh to $50/MWh) is shown in the top panel with the coefficient of variation (CV) shown in the bottom panel. For an 8-hr BESS storage unit we assume a fixed quarterly annuity of $5.3 million (minimum payment under $7/MWh degradation: Base Case), a level that enables finance-ability of the asset.

Figure 5: Boxplot of distribution of cashflows for 8-hr BESS under price error uncertainty

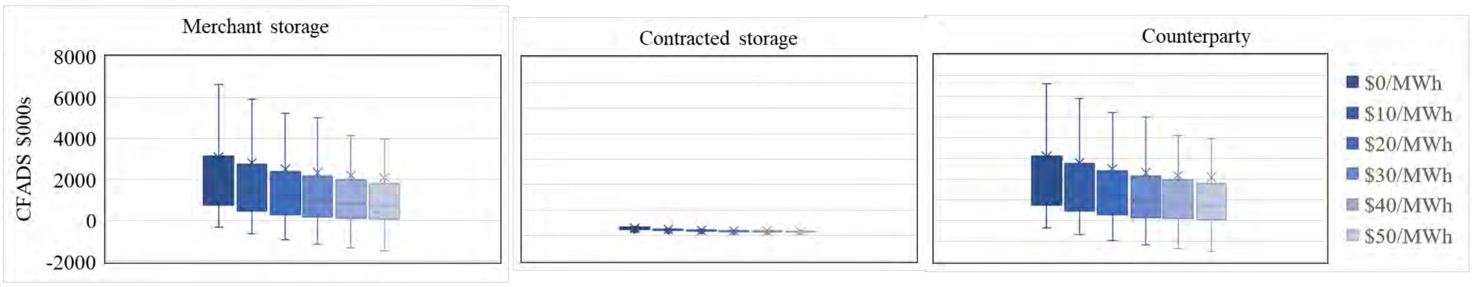
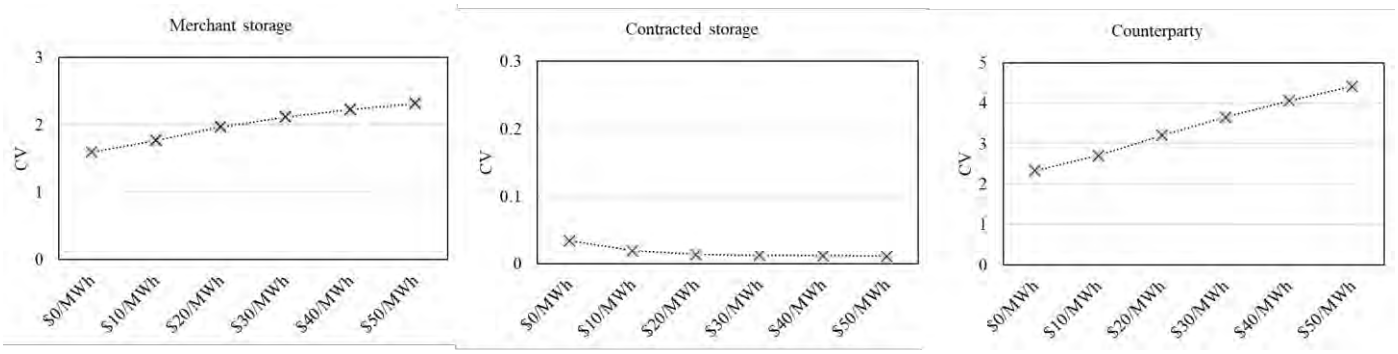


Figure 6: Coefficient of variation (CV) of cashflows for 8-hr BESS under price error uncertainty



It is observed that merchant storage exhibits variation in cashflows from higher price error, particularly relating to downside returns. As standard deviation in price error increases from $0/MWh to $50/MWh, median cashflows for merchant storage declines by 60% ($1.1mn). By contrast, median cashflows for contracted storage reduce by 10% respectively. Bottom quartile cashflows decline by 89% ($0.7mn) for merchant and 8% ($0.1mn) for contracted. This also corresponds with the coefficient of variation for merchant storage increasing with higher price error, while the transfer of operational risk results in a minimal coefficient of variation for contracted storage. The key insight is that as forecast errors increases, under a fully contracted swap the storage owner is essentially protected from price error risk, with such risk shifting to the buy-side counterparty. By contrast a merchant unit remains fully exposed to such risks.

This suggests that under this contract design of full contracting, the transfer of operating risk should attach to the counterparty of the contract, for example via the assignment of trading rights. While it is asserted in centralised storage models that the allocation of operational decision rights can be enabled through the exchange of cashflows, the results above establish the reverse – that the exchange of cashflows must be accompanied by the allocation of operational decision rights. Central agencies may be motivated to pursue to assets under episodes of power system duress. Not possessing the capability to deliver, a fully contracted asset opportunity will motivate the supply-side but the key insight is to ensure operational control is maintained. This then leads to the question of how operational control might be administered

It is common in many project structures for operational bidding decisions to be guided or delegated to automated bidding software yet importantly the allocation of decision rights relating to the selection, renewal and performance management of such software should ideally attach to the counterparty. For commercial counterparties of storage with scalable trading and operational capabilities this is viable, enabled by partitioning of physical storage at the asset level. In the absence of existing electricity market exposures and direct pecuniary incentives, central government agencies as buy-side counterparties will need to specifically consider operational co-ordination, potential delegations or some other objective function. One potential avenue lies in the treatment of such units as centralised assets and integrated within dispatch by the market operator (Jiang and Sioshansi, 2023). Though certain adjustments may need to be made to dispatch from the current single-period real-time dispatch in order to optimise inter-temporal operation and ensure constraint compliance with system integrity and control schemes. This can also have the benefit of prioritising security of supply over profit maximisation, which matters to governments.

Partial contracting invariably improves incentive alignment and compatibility, given the unit owner retains meaningful 'skin in the game' via a minimum percentage of exposure to the market (which should not preclude any form of subsequent hedging in an orderly market). Figure 7 and Figure 8 lay out the boxplot distribution of cashflows and the CV under partial contracting (with volumetric exposures υ ranging from 0.0 to 1.0). This ensures that storage owners bear the risk associated with price error, with exposure to cashflow variability at higher price error. The corollary of this is that even minimal levels of un-contracted capacity expose the storage unit to risk exposure in cashflow variation even under perfect foresight (i.e. standard error of price forecast at $0/MWh) and thus participants will likely reflect such risk into contract valuations and auction bidding.

Figure 7: Boxplot of distribution of cashflows for 8-hr BESS under price error uncertainty – partial contracting (with volumetric exposure υ ranging from 0.0 to 1.0)

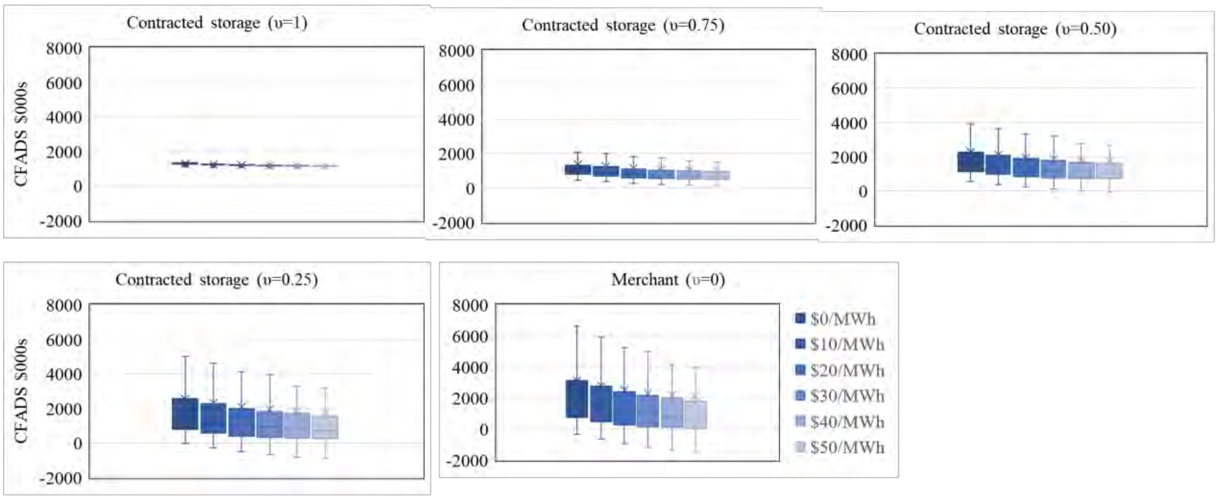
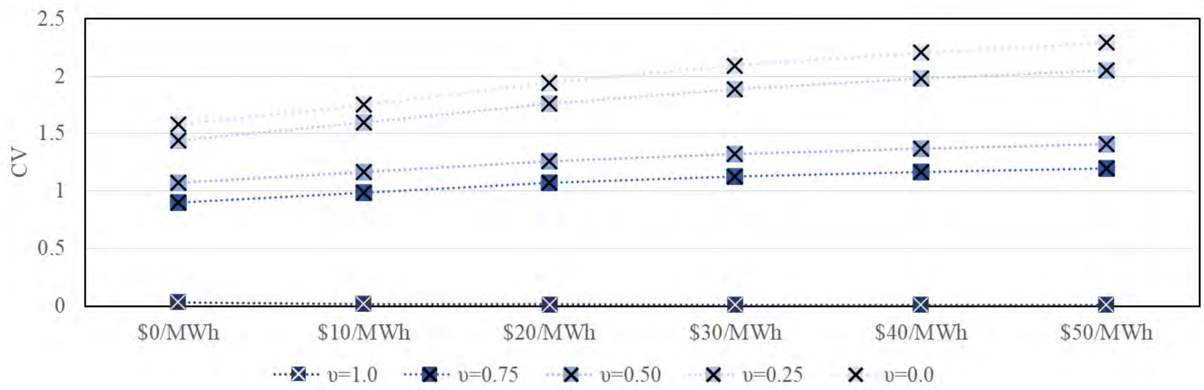


Figure 8: Coefficient of variation (CV) of cashflows for 8-hr BESS under price error uncertainty – partial contracting (with volumetric exposure υ ranging from 0.0 to 1.0)



4.2.2. Contract form asymmetry and incentive compatibility

Given the cashflow volatility associated with storage operations, we consider in this section alternative forms of forward contracts that seek to limit cashflow variability. Specifically, we consider caps, floors and availability contracts.

Floors and availability contracts can be viewed from the perspective of mitigating downside risk. While a floor seeks to ensure a minimum net revenue level, availability contracts provide a source of fixed (or less volatile) revenue that is incremental to project spot exposures. Figure 9 provides the return and financing profile of a 10-hr BESS unit contracted via i). a revenue floor and ii). an availability contract, respectively. It displays annualized minimum, mean, P90 and P10 equity returns and the financial gearing ratio (the ratio of debt over total capital). While both support debt financing and boost equity returns, availability contracts supports higher gearing because the revenue source is incremental. It is also observed that equity returns are maximised through leveraging the project based on the revenue support provided by the hedge – with higher thresholds supporting a non-linear increase in equity returns.

Figure 9: Revenue floor and availability contracts 10-hr BESS – equity returns and gearing

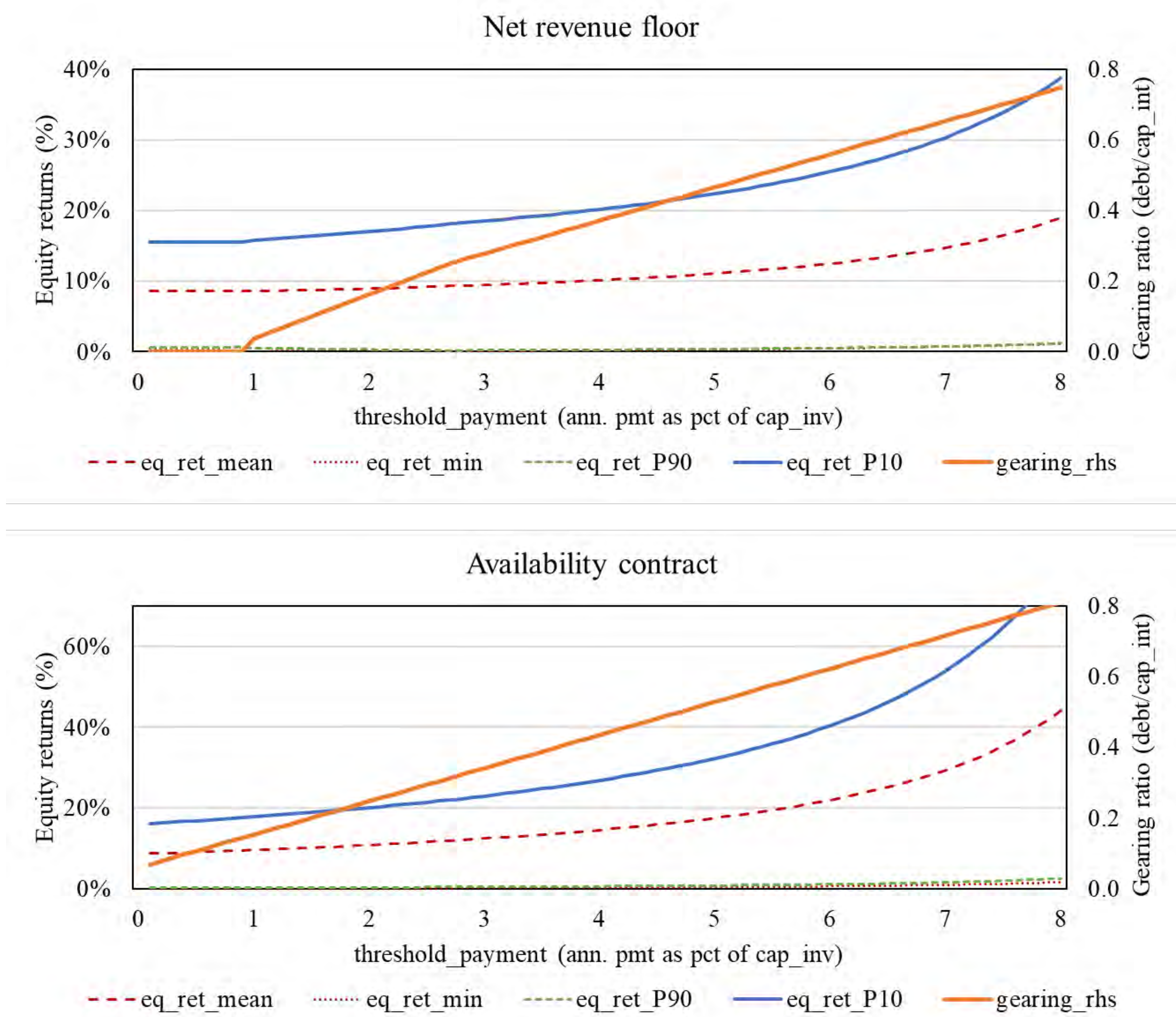
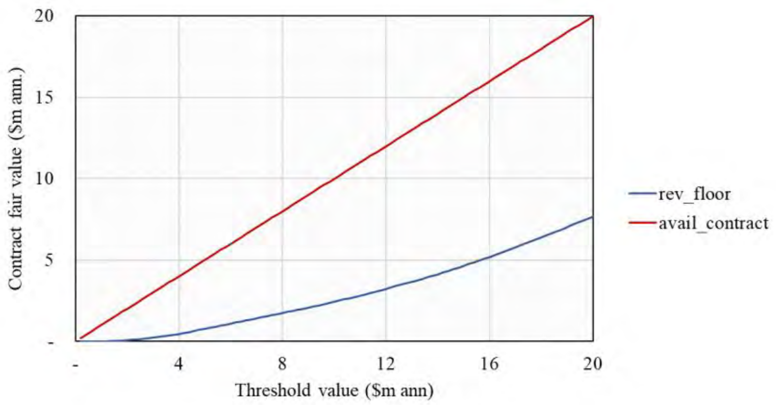


Figure 10 provides the fair value of the contract as viewed from the perspective of the buy-side counterparty for revenue floor and availability contracts – illustrating that while the fair value of availability contracts is linear in the threshold (as an increment to revenues), the option-like nature of floors imply a less than 1:1 relationship between threshold and value. This underscores the complexity of floor valuations given threshold level, storage technical characteristics and threshold[8]. The key implication here being that for assessing financial value in auction award decisions it is not sufficient to rank parties in different locations and of different durations by floor thresholds bid due to the inherent inconsistency in financial exposure.

More fundamentally, and together with the asymmetrical relationship observed between equity returns and thresholds in Figure 9, this also risks the privatization of gains and socialization of losses, a principle that central counterparties acting as quasi-agents for consumers should be acutely aware of, and indeed wary of. It is important to note that a floor also socialises poor dispatch arbitrage – the revenue floor operates regardless of whether the low revenue is due to the lack of market arbitrage opportunities or poor operational performance of the storage unit.

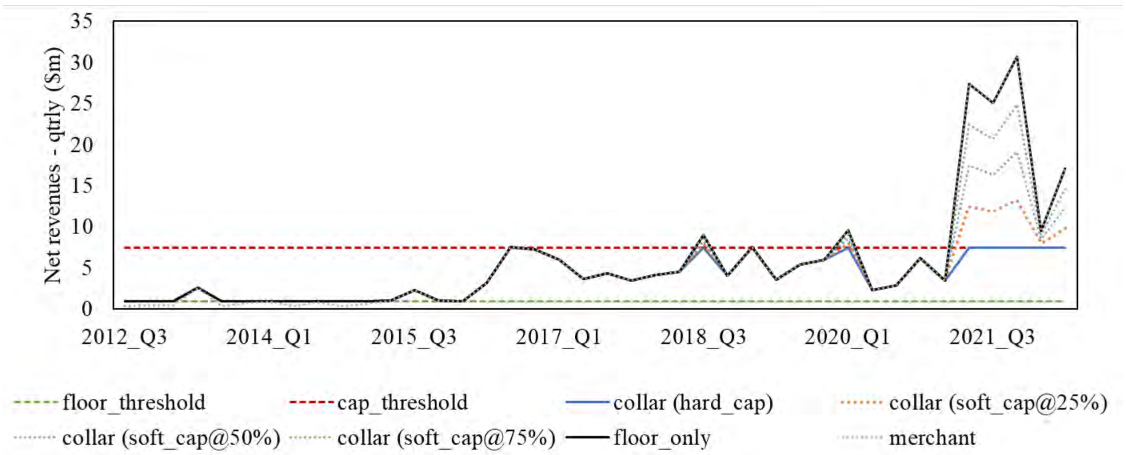
[8] We also illustrate the fair value for a swap of a set threshold and different durations, as well as fair values for a revenue collar in Appendix C.

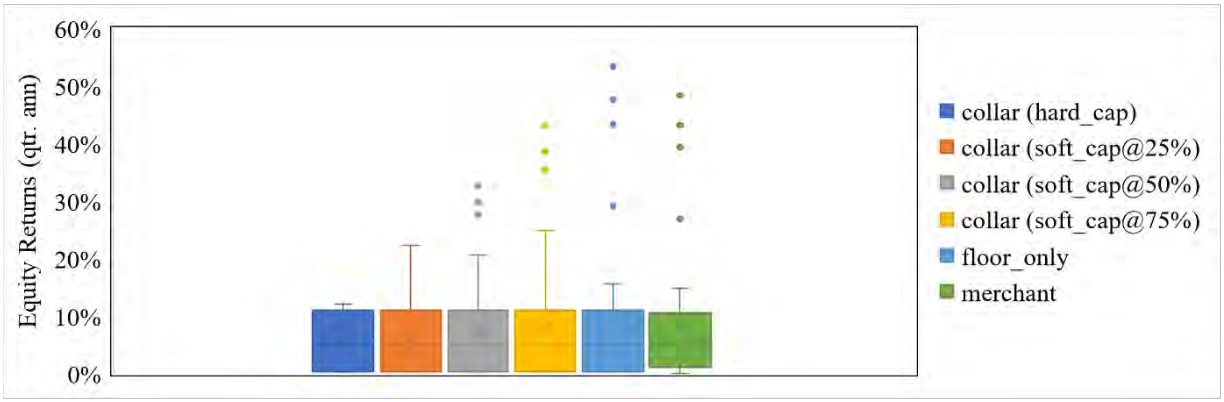
Figure 10: Counterparty fair value for 10-hr BESS for range of threshold values



The natural response in tender structuring is to look to cap revenues for projects to provide minimum guaranteed levels of cashflows that facilitate commercial levels of project finance – resulting in a collaring of revenue between these thresholds. A revenue collar approach has been assessed below– which adds a revenue cap to the floor. This can be in the form of a "hard cap" on revenue, or a revenue-sharing arrangement ("soft cap") beyond the exceedance of a specific threshold. Correspondingly, we term a floor with a hard cap as a "hard collar" and a floor with a soft cap as a "soft collar". We apply a revenue collar to a 10-hour BESS with floor returns scenario equity returns given Figure 11 below illustrates the operation of a revenue collar using quarterly floor threshold of $1m and cap threshold of $7.5 m (corresponding to an annualized cash-on-cash return of 15%). We assess project financials for a range of contract forms comprising collars with a hard cap, collars with a soft cap revenue share ranging from 25% to 75%, floor-only and merchant structures. Figure 11 – top panel shows the quarterly net revenues of the project under each structure illustrating when the threshold is reached and how revenues are shared post the exceedance of the threshold. The bottom panel provides a box plot of equity returns illustrating how cap arrangements bound equity returns.

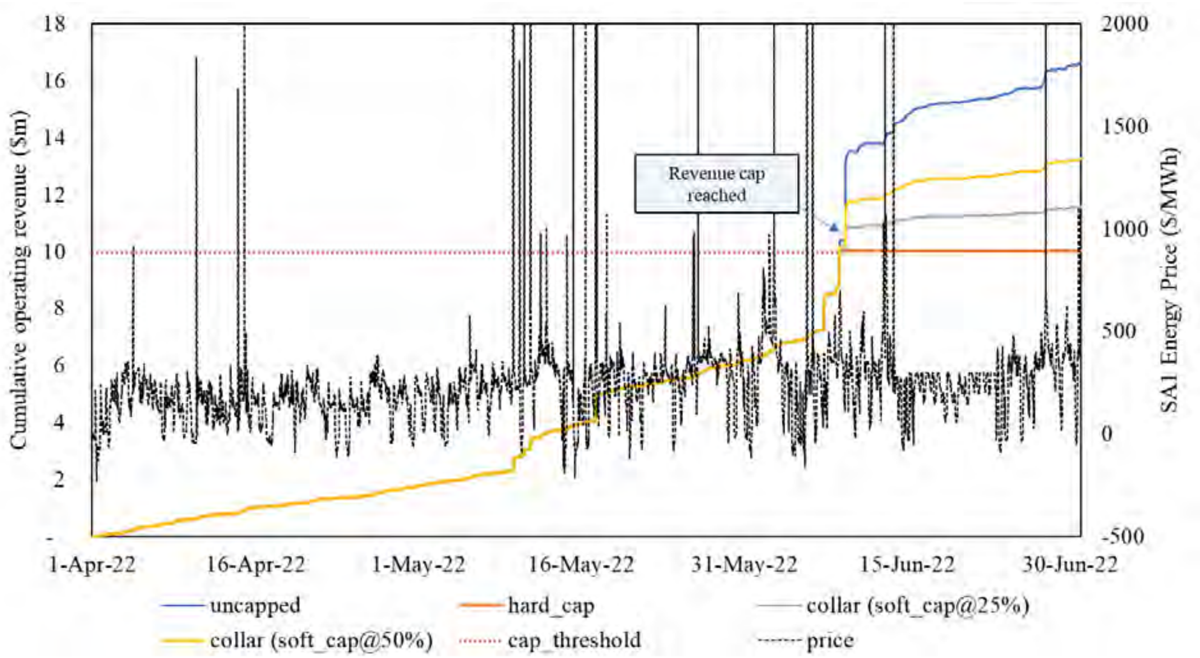
Figure 11: Revenue collar – 10 hour BESS – quarterly net revenues (top panel) and equity returns (bottom panel)





A revenue cap, depending on its structure, can have adverse impacts on dispatch incentives on exceedance of the specified cap threshold. Most notably, Figure 12 provides a hypothetical example of such a situation under the modelled timeline, illustrating cumulative revenues of a 10-hr BESS project during Q2 2022 under a variety of cap/collar structures (including a hard cap, soft cap under a range of revenue shares, and an uncapped structure). Note that under a hard-cap arrangement once the threshold is reached, the unit's operating revenue is capped and it does not accumulate further revenues from spot market operation. Under a partial cap arrangement the project continues to accumulate net revenue though the share is dependent upon the soft cap arrangement. Comparing the hard cap against the soft cap and uncapped arrangement, the project under the former receives no more benefit from optimal operation in the market but incurs the costs of cycling and degradation. This suggests that in such a situation the unit would have minimal incentive to continue to make itself available in the market for the remainder of the period. This is despite the occurrence of continued scarcity and extremely high market price signals. This would be significant concern for centrally contracted arrangements, and may manifest via split operator incentives of maximising market earnings (revenue) and attempts to minimise costs (e.g. minimising battery cycling on high value days rather than using 2 cycles during such days). This illustrates that while a hard cap arrangement may have intuitive appeal in minimizing windfall profits for market participants, it adversely affects incentives for the resource to continue to participate optimally in the market unless contractual side-constraint arrangements are carefully structured and documented.

Figure 12: Effect of revenue caps on dispatch incentives (10 hr BESS) – Cumulative operating revenues during 2Q 2021 under a range of collar / cap structures (hard cap, soft cap, uncapped



4.2.3. Developing yardsticks for storage dispatch

The examples above illustrate that certain contract forms, while well-intentioned and simple, can lead to challenges in maintaining incentive alignment with socially optimal and welfare maximising dispatch. In particular the hedge offered by particular contract forms can mute incentives to participate in the market.

Motivated by the work of Newbery (2022) in developing yardstick contracts for renewables, we propose a yardstick contract for storage based on the contractual form set out in Section 2. Rather than the floating component of the derivative contract referencing actual revenues we specify a net revenue yardstick based on ex-post simulations of optimal dispatch given price signals. This creates the incentive to maximise profits while preserving revenue stability for the project level if it behaves optimally.[9]

Figure 13 provides a boxplot of the distribution of cashflows under a merchant project structure, under a yardstick contract structure and a standard revenue swap structure for a range of price error scenarios, while Figure 14 provides the CV for the same. It is observed that while the swap preserves a low CV under all price error scenarios thereby muting incentives for optimal dispatch, the stability of cashflows for a yardstick contract scales on how well the unit follows dispatch incentives. A project that is able to better predict prices and follow price signals will benefit from stable cashflows and a low CV, while worsening price error will flow through in cashflow variation. This aligns incentives with spot market signals. While it is understood that storage may not realistically expect to be able meet idealized outcomes, and thus parties may reflect that in its contract bid – the operational incentives remain for the unit to attempt to do so to the best of its capability, as the settlement is against such behaviour.

Figure 13: Boxplot of distribution of cashflows for 8-hr BESS under price error uncertainty – under merchant, yardstick and swap arrangements

[9] Spread contracts as discussed in Renewable Energy Hub (2020) appear to have a similar motivation with the derivative index defined as a spread between a set of maximum and minimum energy prices across a period (typically an operating day). The difference being that the defence of the energy spread is considered the relevant yardstick, and that ancillary service revenues are not considered.

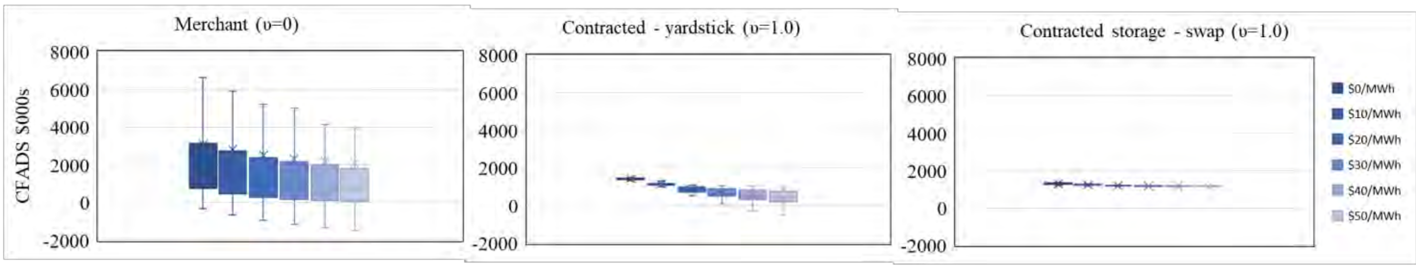
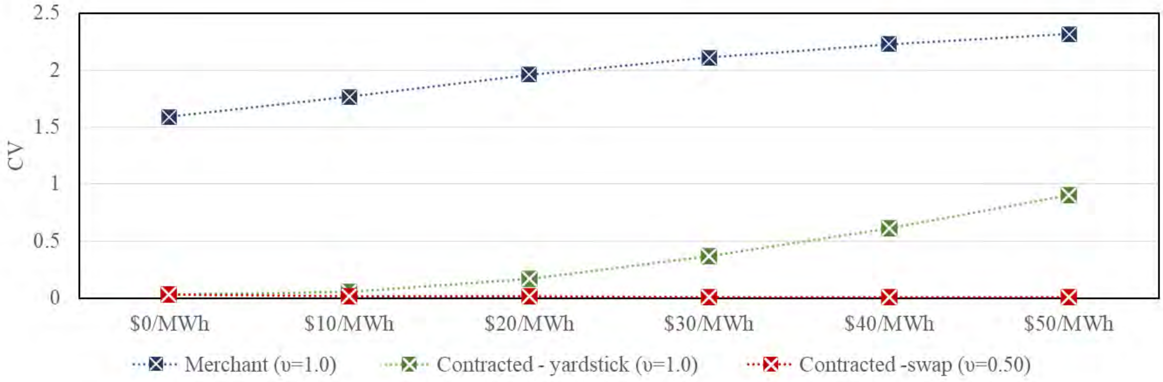


Figure 14: Coefficient of variation (CV) of cashflows for 8-hr BESS under price error uncertainty – – under merchant, yardstick and swap arrangements



While these results bode positively for further consideration and research into the development of appropriate yardsticks for storage we also note that our case study necessarily incorporates a generalization of contracts. Structuring real-world contracts requires careful consideration to the technical constraints on storage operation, including imposed by as a condition of connection access, OEM warranties, environmental permits, safety requirements and water rights (for pumped hydro). Examples include duty cycle constraints for BESS, and ramping, spill and start-up constraints for pumped hydro. This suggests an applicability to granular and bespoke contracting arrangements though larger scale programs could also be adopted with acceptable generalizations. Moreover as the 'yardstick' reflects an optimal outcome without curtailment or constraints it also requires the storage owner to give close consideration to its location in the network, as well as its impact of security constraints. This further supports the alignment of interests between private and public value. One particularly option could also be to incorporate a yardstick to the floor side of a soft collar arrangement, which preserves the operational incentives on the downside.

5. Policy implications

The results outlined herein have important policy implications for the procurement and risk management as it relates to storage resources in a hybrid electricity market.

5.1. Government initiated tenders for storage

Given the gap in policy action on climate change at the Commonwealth levels in Australia in recent years, sub-national governments have sought to fill the void with direct contracting via large scale auctions for renewables (Nelson, Nolan and Gilmore, 2022). Buoyed by the successful execution of these auctions and combined with impetus for centrally planned resource development at strategic levels, storage procurement strategies are increasingly being incorporated into net zero objectives and forming part of certain sub-national government plans. No doubt parallel conditions exist in other jurisdictions around the world vis-à-vis storage procurement.

While parties may retain a preference for simple contract structures, as operating resources electricity storage assets represent a higher order of complexity given inter-temporal and multi-service dimensions. As such, governments and central agencies need to be acutely aware of the impact of contract form on the incentives of participants across aspects of market operation, risk hedging and investment. In particular, the incentives to participate in real-time dispatch can be directly affected by the structure of the risk hedge, which can be brought to bear in conditions of scarcity where the maximization of resource availability is critical to service load.

A preference for simplicity and broad scale application may lead to structures like 'availability contracts' as part of a storage certificate scheme, though recognizing the inherent subsidisation through revenue additionality. Moreover, as such contracts are an incremental payment and not settled against spot outcomes, it does not provide any guarantee that such procurement will be actually add value to the system, in essence merely requiring obligors to purchase a minimum amount of a defined product – in this case storage. This is further complicated by the inability of clauses requiring minimum availability to appropriately reflect the operational value of storage participation at different times and for different services. Finally in the absence of direct pecuniary interests and a comprehensive risk management program for government agencies (which we return to below) there is limited sharpness in incentives to actually align procurement decisions with consumer outcomes. Tolling and revenue swap type arrangements also provide a simple reallocation of cashflows but the delegation of operational rights must flow to the swap counterparty for similar reasons; this may be more challenging for some central processes.

Alternatively, if central agencies are seeking to providing a risk hedge service to participants driven by the motivation of missing markets, a granular analysis of risk and incentive compatibility is required. Caps and floors provide a viable alternative by collaring of revenue between thresholds – in a way that provides minimum returns but limits windfall gains. However our clear preference is for caps with (i) soft collar arrangements due to operational incentive effects during scarcity and (ii) we also prefer that the floor side of the collar be indexed off a yardstick style arrangement – given it maintains performance incentives. While this may comprise a degree of simplicity in structure the incentive alignment with optimal operational behaviour is important for both short run and long run investment decision making. Further consideration of technical constraints in the yardstick optimization is an important extension to this line of work; as is the modelling of different participant behavioural assumptions (such as price-setting and strategic storage behaviour).

5.2. Quasi-agency and risk frameworks

By providing a risk-trader functionality, governments are seeking to fill 'missing market' gaps due to incompleteness in risk-hedging markets. Yet this comes with the risk of entering into complex and risky derivative arrangements without a direct pecuniary incentive where the brunt of any adverse financial impacts will likely be directly borne by taxpayers. This is especially in light of the dynamic and heavy-tailed nature of energy-only electricity market prices.

Given the programmatic nature of storage and renewable procurement and the complexity of instrument valuation and portfolio exposures, it would behove a central agency to adopt a robust and disciplined risk assessment and portfolio management frameworks (Billimoria and Poudineh, 2019; Billimoria *et al.*, 2022) if hybrid markets are to be a matter of course. There is also the precedent threshold question of whether governments or central agencies are well placed to enter into complex derivative arrangements in the first place.

Furthermore, while recent price trends offer clues, there is also a broader structural question of how price formation may occur in electricity markets dominated by zero short-run marginal cost renewables and storage.

6. Conclusions

In the context of rapid decarbonization imperatives, the focus of procurement in hybrid electricity markets has broadened beyond renewables to include electricity storage. Our analysis suggests contract design for storage is a complex task, and requires careful and granular analysis of game theoretic motivations and interactions with market scheduling. Auction designers with a preference for simpler structure may be attracted by availability or swap style contracts, though this should recognize issues of inherent subsidisation and lack of contract quality assurance. For central agencies seeking to offer a risk hedging service and improve incentive alignment we propose a revenue collar with a soft cap and a yardstick contract basis on the floor; this mitigates dispatch distortions while maintaining cashflow stability for storage project investors.

Appendix A: Granular FCAS constraints for NEM simulation

The constraint formulation governing the delivery of multiple regulation and contingency services is set out below. Consistent with NEM market design, we define a set of eight frequency control services $r \epsilon FR$ broken into regulation and contingency services. We denote these services based on the service category, between regulation services REG and contingency services C, and direction $+$ for up reserve and for – for down reserve. Contingency markets are further classified by time period – 6 second (6), 60 second (60) and 5 minute (5). For example, 60 second contingency down services are denoted as R^{C60-}, while the set of all contingency services are denoted as R^C. It is assumed that regulation and contingency services are mutually exclusive given that regulation operates across the dispatch period overlapping with all contingency services. Contingency services are not mutually exclusive with each other as they each operate over different timeframes.

$$p_t^D - p_t^C + p_t^{REG+} + p_t^r \leq P^R \quad \forall\, r \,\epsilon\, \{R^{C+}\} \qquad \text{(A.1)}$$

$$P^R + p_t^D - p_t^C \leq p_t^{R-} + p_t^r \qquad \forall\, r \,\epsilon\, \{R^{C-}\} \qquad \text{(A.2)}$$

Appendix B: Contracting incentives for revenue swap under simplified case

For a storage unit fully contracted $(v = 1)$ under a net revenue swap based on actual net revenues (from spot and reserve markets), contracting proceeds are $\Phi_c = \phi - \varphi_T$. Incorporating the impact of contract form on operational incentives, the sum of short run operational surplus and contract difference payment can be stated as below based on (7) and (8):

$$\Pi = \Phi_s + \Phi_c = \phi - \sum_{t\epsilon T} c^d (p_t^D + p_t^C + k^+ p_t^{R+} + k^- p_t^{R-}) \qquad \text{(B.1)}$$

There is some evidence to suggest that to date participants do not consider reserve utilization in reserve offerings (Gilmore, Nolan and Simshauser, 2022). Assuming that $k^+ = k^- = 0$ then Π simplifies to $\Pi = \phi - \sum_{t\epsilon T} c^d (p_t^D + p_t^C)$. Assuming a non-negative c^d, any charge or discharge would reduce total surplus. Therefore we can see that Π is maximised at $p_t^D = p_t^C = p_t^{R+} = p_t^{R-} = 0$. Under such a situation accounting for contractual incentives under a revenue swap the owner of the storage resource is averse to any further dispatch of the asset.

Appendix C: Fair valuation for Floor (under different storage durations) and Revenue collar (across floor and cap thresholds)

Figure C.1 Fair value of Floor (with $1m floor threshold) for BESS of different storage durations

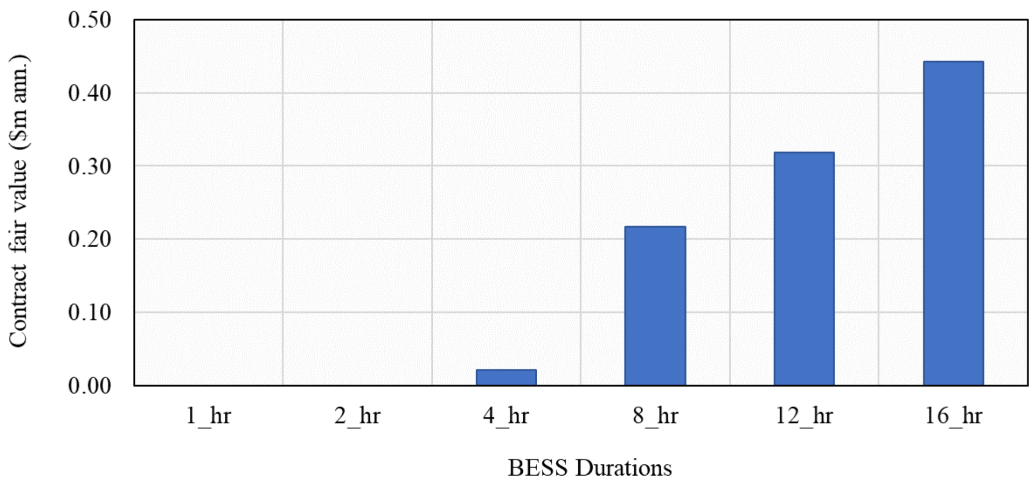
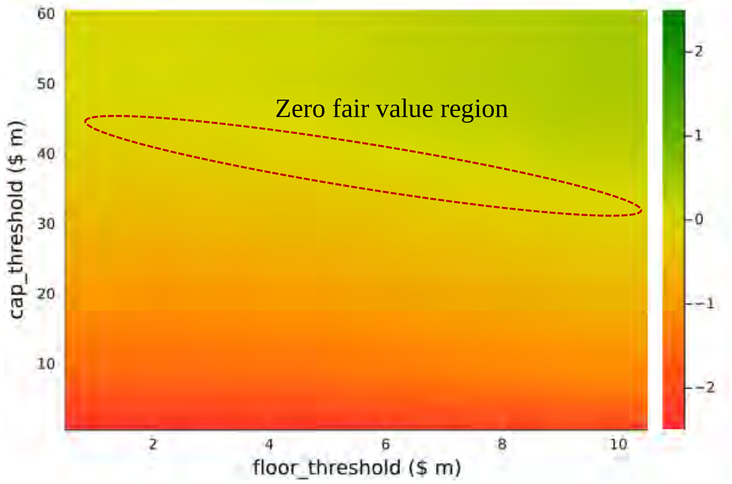


Figure C.2 Fair value of revenue collar for 10-hr BESS given different cap and floor thresholds



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