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Electricity Contract Co-Design – Supporting Analysis

August 2026

These slides were used as a basis for discussion around risk allocation and key terms. Please refer to the provided minutes and draft product sheets for latest positions.

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Bulk Energy Contracts – Risk Allocation

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Product Overview - Reference ex-post DWA price swap

A bulk energy contract provides:

- **A buyer** with a fixed volume from renewable resources.
- **A seller** with long-term, contracted revenue at a Fixed Price.

The swap works by fixing the price received per an agreed (fixed) MWh of output from a reference fleet. This reduces the price risk that buyers are exposed to from individual projects, while retaining incentives for the sellers to outperform the reference.

Table: Key Settlement Terms

Key Term	Description
Calculation Period	The Calculation Period will be aligned to the AEMO NEM settlement calendar (options include weekly, fortnightly, monthly or quarterly).
Contract Volume (MWh)	A fixed volume (MWh) of generation within the defined NEM Region.
Fixed Price ($/MWh)	The Fixed Price is the agreed amount ($) to be paid per MWh of reference fleet output that forms the basis of the swap.
Reference Price ($/MWh)	The dispatch weighted-average price ($/MWh) of the fleet within the Reference Index.
Reference Index	TBC.
Settlement Amount ($)	$Settlement\ Amount = Contract\ Volume \times (Reference\ Price - Fixed\ Price)$

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Product Overview – Reference Ex-Post Revenue Swap

A bulk energy contract provides:

- **A buyer** with ex-post market revenue for fixed MW of reference/average wind-farm.
- **A seller** with Fixed Revenue per MW + any net market revenue above reference/average wind-farm of same size.

The swap works by fixing the revenue received per an agreed MW of output from an ex-post index derived from the average wholesale revenue captured by the projects within the regional index. This reduces the volume and price risk that buyers and sellers are exposed to from individual projects, while retaining incentives for the sellers to outperform the reference.

Table: Key Settlement Terms

Key Term	Description
Calculation Period	The Calculation Period will be aligned to the AEMO NEM settlement calendar (options include weekly, fortnightly, monthly or quarterly).
Contract Capacity (MW)	A fixed capacity (MW) of generation within the specified region
Fixed Revenue ($/MW)	The Fixed Revenue is the agreed amount ($) to be paid per MW of Reference Index capacity that forms the basis of the swap for the Calculation Period.
Reference Revenue ($/MW)	The relevant revenue ($) per MW calculated according to the Reference Index.
Reference Index	TBC
Settlement Amount ($)	$Settlement\ Amount = Contract\ Units \times (Reference\ Revenue - Fixed\ Revenue)$

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Product Overview – Regional Reference PPA

A bulk energy contract provides:
- **A buyer** with exposure to the index performance of a whole fleet of renewable resources.
- **A seller** with long-term, contracted revenue at a Fixed Price for the reference volume.

The swap works by fixing the price received per MWh of output from the reference index within the relevant region. This reduces the price risk that buyers are exposed to from individual projects, while retaining incentives for the sellers to outperform the reference.

Table: Key Settlement Terms

Key Term	Description
Calculation Period	The Calculation Period will be aligned to the AEMO NEM settlement calendar (options include weekly, fortnightly, monthly or quarterly).
Contract Capacity (MW)	A fixed capacity (MW) of wind/solar generation within the specified region
Fixed Price ($/MWh)	The Fixed Price is the agreed amount ($) to be paid per MWh of reference fleet output that forms the basis of the swap.
Floating Price ($/MWh)	The Spot Price (in $/MWh) set by AEMO for a Trading Interval at the Regional Reference Node.
Reference Production Index	$Reference\ Production\ Index = \frac{Reference\ Power\ Output}{Reference\ Capacity}$, where: • Reference Power Output is the total generation output (MW) of the Reference Fleet in a Trading Interval. • Reference Capacity is the total capacity (MW) of generators within the Reference Fleet.
Notional Quantity (MWh)	The quantity of electricity (MWh) that applies for a Trading Interval. $Notional\ Quantity = Contract\ Capacity \times 1/12 \times Reference\ Index$
Settlement Amount ($)	$Settlement\ Amount = \sum_1^n Notional\ Quantity \times (Floating\ Price - Fixed\ Price)$, where n is the number of Trading Intervals in the Calculation Period .

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Buyer and Seller Perspectives

Seller

- **Volume:** Challenging to defend a fixed volume obligation due to inherent risks of VRE.
- **Price:** Values price certainty and views uncertain and low spot prices as a risk.
- **Shape:** Values revenue certainty by aligning generation with periods of high prices. Views matching a fixed load shape as a risk.

Bulk Energy Service Agreement

The bulk energy service agreement needs to balance buyer and seller needs for certainty and price, delivered from an inherently variable resource.

Buyer

- **Volume:** Values certainty over volume and views under-delivery as a risk.
- **Price:** Values lower cost to obtain required volume and views uncertain costs as a risk.
- **Shape:** Values alignment between generation purchased and load. Prefers to mitigate against higher price periods.

Settlement Risk Allocation – Volume Risk

These slides were used as a basis for discussion around risk allocation and key terms. Please refer to the provided minutes and draft product sheets for latest positions.

Who bears the risk of total volumetric VRE output differing from expectations?

Contract Structure	Seller risks	Buyer risks
0 – Run-of-plant PPA	• The seller does not have a fixed volume obligation under the contract, but project revenue is dependent on volume settled under PPA.	• Whilst the buyer only pays for volumes generated by the seller, the buyer does not have certainty over volumes to be delivered (and is hence exposed to idiosyncratic and systematic risks).
1 – Reference ex-post DWAP swap	• The seller holds the risk of delivering a fixed Contract Volume (idiosyncratic and systematic risk).	• The buyer receives a fixed Contract Volume, irrespective of seller output.
2 – Reference ex-post revenue swap	• The seller does not have a fixed volume obligation, but is required to pay the ex-post revenue of the fleet. If it doesn't produce, then it won't have revenue to make payments under the contract (retains idiosyncratic risk and some systematic risk)	• Buyer does not receive a hedge for a specific volume, rather receives the net revenue of the fleet. Systematic volume risks will impact revenue of reference index
3 – Regional Reference PPA	• The seller does not have a fixed volume obligation, but holds the risk of performing in line with the reference index (retains idiosyncratic risk).	• Buyer receives a hedge for the Reference Volume of the fleet, but is still exposed to underperformance (systematic risk).

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Risk Allocation – Price Risk

Who bears the risk of spot prices differing from forecast?

Contract Structure	Risk to Seller	Value to Buyer
0 – Run-of-plant PPA	• Seller receives the Fixed Price for volume generated. • Where prices are above forecast, the seller loses upside potential.	• Where prices are below forecast, the buyer pays above market value for volume.
1 – Reference ex-post DWAP swap	• The seller is exposed to differences between the Reference Price (DWAP) and project DWAP (idiosyncratic risk).	• The buyer is exposed to the difference between the Fixed Price and the reference DWAP.
2 – Reference ex-post revenue swap	• Seller is exposed to differences between the Reference Revenue and project revenue (idiosyncratic risk), which price is one component of (noting volume is also a factor).	• The buyer is exposed to the difference between the Fixed Revenue and the Reference Revenue (systematic risk).
3 – Regional Reference PPA	• Seller is exposed to differences between the Reference Price (DWAP) and project DWAP (idiosyncratic risk).	• The buyer is exposed to differences between the Floating Price and Fixed Price.

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Risk Allocation – Shape Risk

Who bears the risk of VRE output aligning with valuable periods?

Contract Structure	Risk to Seller	Value to Buyer
0 – Run-of-plant PPA	• The seller has no obligations to match output to a shape.	• Buyer holds the risk of the seller's shape matching their desired profile.
1 – Reference ex-post DWAP swap	• Seller is exposed to differences between the Reference Price (DWAP) and project DWAP (idiosyncratic risk).	• Buyer is exposed to the difference between the Spot Price and the reference DWAP (systematic risk).
2 – Reference ex-post revenue swap	• Seller is exposed to differences between the Reference Revenue and project revenue (idiosyncratic risk) and hence shape risk.	• Buyer is exposed to the difference between the Fixed Revenue and the Reference Revenue (systematic risk).
3 – Regional Reference PPA	• Seller is exposed to differences between the Reference Price (DWAP) and project DWAP (idiosyncratic risk).	• Buyer holds the risk of the Reference Profile matching their desired profile.

Settlement Risk Allocation – Summary

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Contract Structure	Risk to seller			Value to buyer		
	Volume	Price	Shape	Volume	Price	Shape
0 – Run-of-plant PPA						
1 – Reference ex-post DWAP swap						
2 – Reference ex-post revenue swap						
3 – Regional Reference PPA						

Shaping Contract Overview and Analysis

These slides were used as a basis for discussion around risk allocation and key terms. Please refer to the provided minutes and draft product sheets for latest positions.

1. Product Overview - Shaping

The spread swap product provides:

- **A buyer** with reduced exposure to wholesale price volatility in exchange for a fixed premium. They are essentially hedging against the high/low in wholesale market (similar to a virtual toll, however with nominations set by a third party).
- **A seller** with stable cash-flows from premiums which should improve bankability.
- The **seller is not required to physically defend the agreed discharge/charge blocks**, although this may be mandated by lenders.
- The **seller should consider MLF, Curtailment and Round-Trip Efficiency** losses in setting its premium (seller retains MLF, curtailment & RTE risks).

Table: Key Settlement Terms

Key Term	Description
Floating Price (FP)	The Spot Price (in $/MWh) set by AEMO for a Trading Interval at the Regional Reference Node.
Fixed Spread ($/MWh)	The agreed difference ($/MWh) between the average Floating Price during defined nomination blocks that forms the basis of the swap.
Calculation Period	The Calculation Period will be aligned to the AEMO NEM settlement calendar (options include weekly, fortnightly, monthly or quarterly).
Contract Capacity (MW)	The contracted unit in MW per Contract Hour in the Calculation Period (flat shape).
Contract Hours	The number of defined hours per day within the Calculation Period.
Settlement Amount ($)	Settlement occurs at the end of the Settlement Period. $Settlement\ Amount = Contract\ Unit \times Contract\ Hours \times \sum_1^n (Realised\ Spread - Fixed\ Spread)$ where n equals the number of days in the Calculation Period.
Realised Spread ($/MWh)	$Realised\ Spread = Discharge\ Price - Charge\ Price$, where: Discharge Price ($/MWh) is the average Floating Price during the defined Discharge Period(s) for a Daily Shaping Period; Charge Price ($/MWh) is the average Floating Price during the defined Charge Period(s) for a Daily Shaping Period.

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Settlement Risk Allocation

Contract Structure	Risk to Seller	Value to Buyer
Volume	• The seller holds the risk of defending the agreed volume of the spread (capacity x hours). • Seller takes curtailment, MLF and RTE risks	• The contract volume is fixed and hence the buyer is not exposed to volume risk.
Price	• The seller receives the Contract Premium for the agreed volume.	• If realised spread falls below premium, then buyer must pay the shortfall.
Shape	• The seller holds the risk of dispatching to align with nomination blocks.	• The buyer is exposed to the price difference between the nominated blocks and the actual realised high/low periods.

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1. Product Overview – Settlement Examples

The below tables shows settlement of the spread product for high (example 1) and low (example 2) realised spreads (RS) for illustrative purposes. The settlement approach is anticipated to be largely independent of how the realised spread is determined.

Table: Settlement Example Parameters

Parameter	Example 1	Example 2
Contract unit (MW) – **CU**	100	100
Contract hours (hours) – **CH**	4	4
Contract volume *CU*CH* – **CV** (MWh)	400	400
High average ($/MWh)	222	**158**
Low average ($/MWh)	48	48
Realised spread ($/MWh) – **RS**	174	**110**
Contract premium ($/MWh) – **CP**	120	120
Actual sent out energy (MWh) - **SOE**	400	400

Table: Settlement Example Calculations

		Formula	Example Calculation 1	Example Calculation 2
Seller (project)				
Merchant	Seller gets	*SOE x RS*	400 * 174 = **$69,600**	400 * **110** = **$44,000**
Contract	Seller pays	*CV x (CP-RS)*	400 * (120-174) = **-$21,600**	400 * (**120-110**) = **$4,000**
Net position		*Merchant + Contract*	$69,600 - $21,600 = **$48,000**	$44,000 + $4,000 = **$48,000**
Buyer (ESEMA)				
Contract	Net position	*- CV x (CP – RS)*	- 400 * (120-174) = **$21,600**	- 400 * (**120-110**) = **- $4,000**

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1. Product Overview - Spread Options

The WG considered five options for defining the realised spread. The table below describes each of these options in detail.

Table: Spread Options

Spread Options	Description
1. Fixed contiguous 4-hr block spread	• Spread measured as the difference between the average of the Floating Price between 10:00 – 14:00 (low period) and 16:00 – 20:00 (high period).
2. Pre-dispatch contiguous 4-hr block spread*	• **Spread measured between the lowest and highest average 4-hr contiguous blocks within a 24-hour period.** • **Block timing is set for the day based on AEMO pre-dispatch prices.** • **Actual spread is determined ex-post based on the ex-ante blocks.**
3. Pre-dispatch non-contiguous 4-hr block spread	• Same as Option 2, but the 4-hr charge/discharge period can be made up of any combination of 1-hr blocks. • BESS must fully discharge before charging
4. Residual demand contiguous 4-hr block spread*	• **Same as Option 2, but block timings are set using the residual demand profile (regional operational load after variable renewables).**
5. Residual demand non-contiguous 4-hr block spread	• Same as Option 3, but block timings are set using the residual demand profile (regional operational load after variable renewables).

* ASL's analysis has indicated the contiguous block options appear preferable to non-contiguous, based on achieving similar outcomes for significantly reduced operational complexity.

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Analysis Overview

ASL has undertaken analysis to support the Electricity Contract Co-Design Working Group's consideration of Shaping and Firming Products for the Electricity Services Entry Mechanism. This analysis considered both historical data and [redacted]

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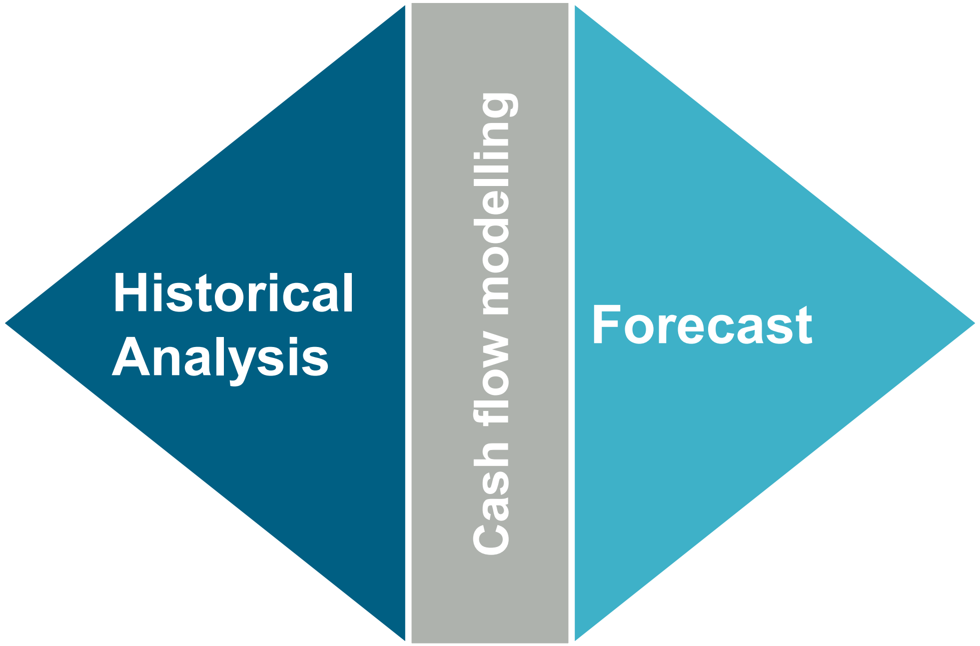
1. Review historical data to identify trends that may impact product design.
2. Use historical data to estimate potential cash-flow impact of key bankability risks.



4. Test impact of design features / project considerations on estimated contract premiums.

3. Estimate required contract premiums for market entry.

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Analysis Overview

Shaping Product

1.

Summarise the proposed product and settlement mechanics

2.

Analyse historical data and theoretical achieved spreads

3.

Estimate premium required for a new entrant battery

4.

Assess identified bankability risks

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1. Product Overview - Spread Options cont.*

- The four charts below demonstrate the spread options in an example day. For the purposes of this analysis, it is assumed that the block timings are set at 4pm the day prior and the BESS is fully charged. Setting the blocks at 4pm allows for the BESS to capture the upcoming evening and/or morning peak.
- For the selected day, the blocks defined by spread Option 5 (Residual demand non-contiguous 4-hr block spread) were the same as Option 4 and are not shown for brevity.
- For this example day, the fixed contiguous option outperforms the dynamic pre-dispatch options as more closely aligns with operation with perfect foresight.

Figure: Option 1 - Fixed contiguous 4-hr block spread (Example)

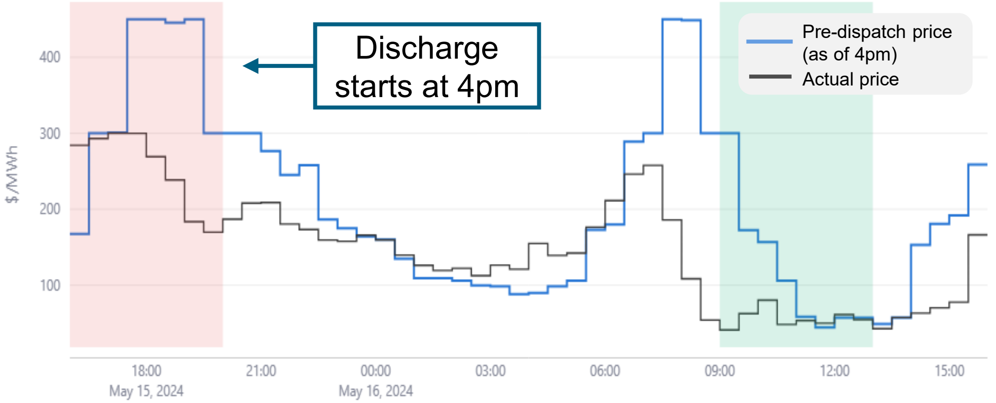


Figure: Option 2 - Pre-dispatch contiguous block spread (Example)

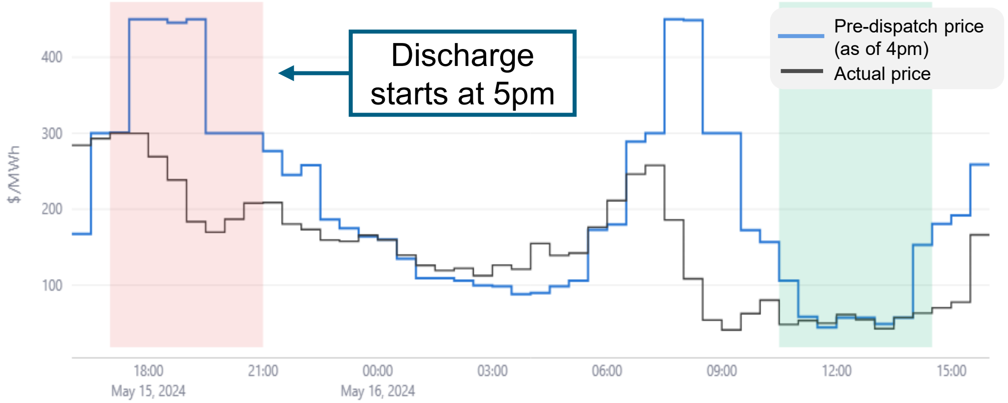


Figure: Option 3 - Pre-dispatch non-contiguous block spread (Example)

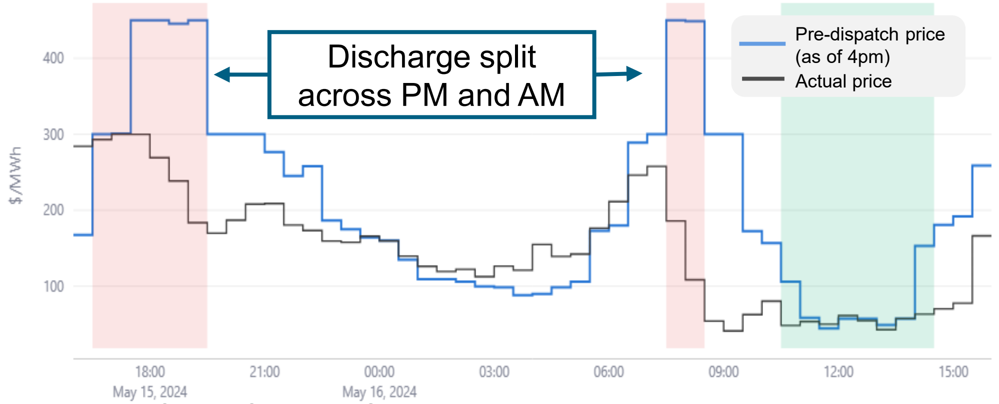
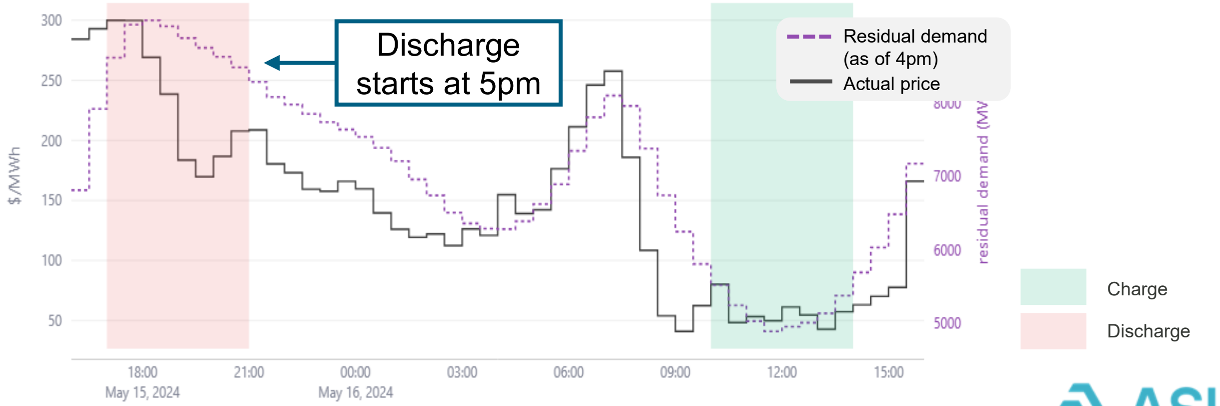


Figure: Option 4/5 – Residual demand contiguous block spread (Example)



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2. Historical Analysis – Spread Options

- As shown below for NSW and SA, **realised spreads have significantly increased over time.** Average spreads between 2022 and 2026 are approximately 2 to 3 times higher than spreads between 2016 to 2021. 2026 spreads decreased from 2025. Similar trends were observed for other NEM states but are not shown for brevity.
- Spreads in SA are generally higher than those in NSW, which could be indicative of the higher penetration of renewables in SA than NSW.
- Realised spreads using the **static block method appear to be lower than either pre-dispatch** method. However, contiguous and non-contiguous spreads are similar.
- Noting the complexity in non-contiguous spreads and similar historical achieved spreads, the **contiguous pre-dispatch and residual demand options appears to best strike the balance between achieved spread and product simplicity.**

Figure: 10-Year Historical Achieved Spreads (NSW)

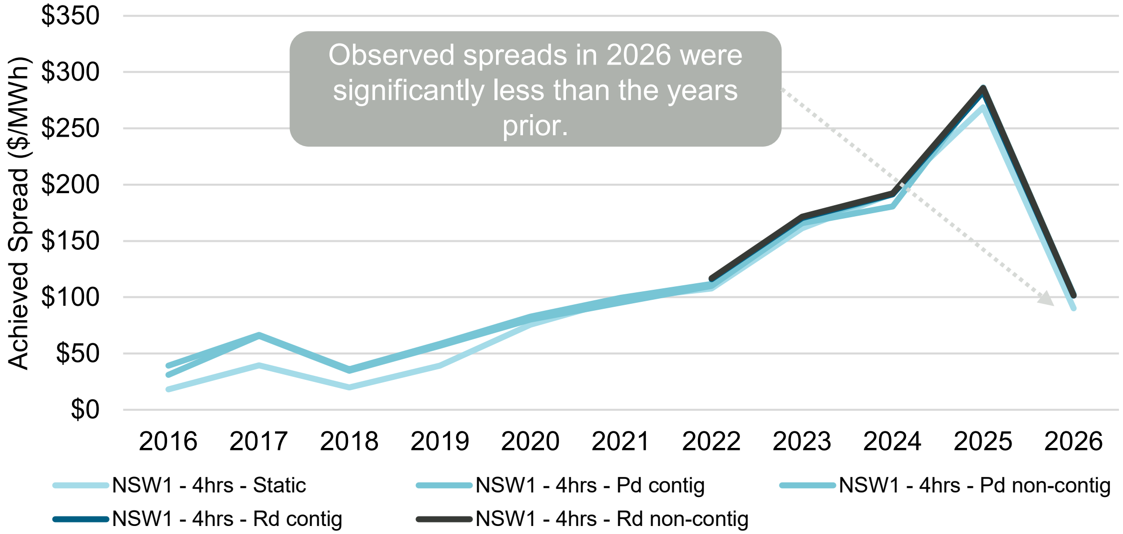

Figure: 10-Year Historical Achieved Spreads (SA)

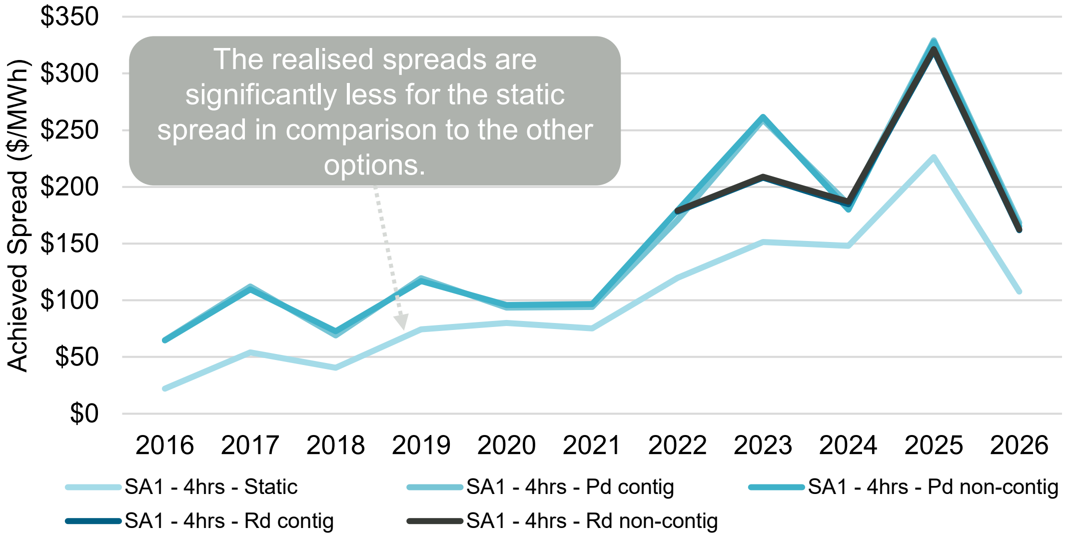

Table: Contrasting average spreads in 2016 – 2021 against 2022 – 2026

Period	NSW1 - 4hrs - Static	NSW1 - 4hrs - Pd contig	NSW1 - 4hrs - Pd non-contig	NSW1 - 4hrs - Rd contig	NSW1 - 4hrs - Rd non-contig	SA1 - 4hrs - Static	SA1 - 4hrs - Pd contig	SA1 - 4hrs - Pd non-contig	SA1 - 4hrs - Rd contig	SA1 - 4hrs - Rd non-contig
2016 to 2021	$48	$61	$64	N/A	N/A	$58	$92	$93	N/A	N/A
2022 to 2026	$164	$169	$171	$172	$174	$151	$222	$223	$211	$212

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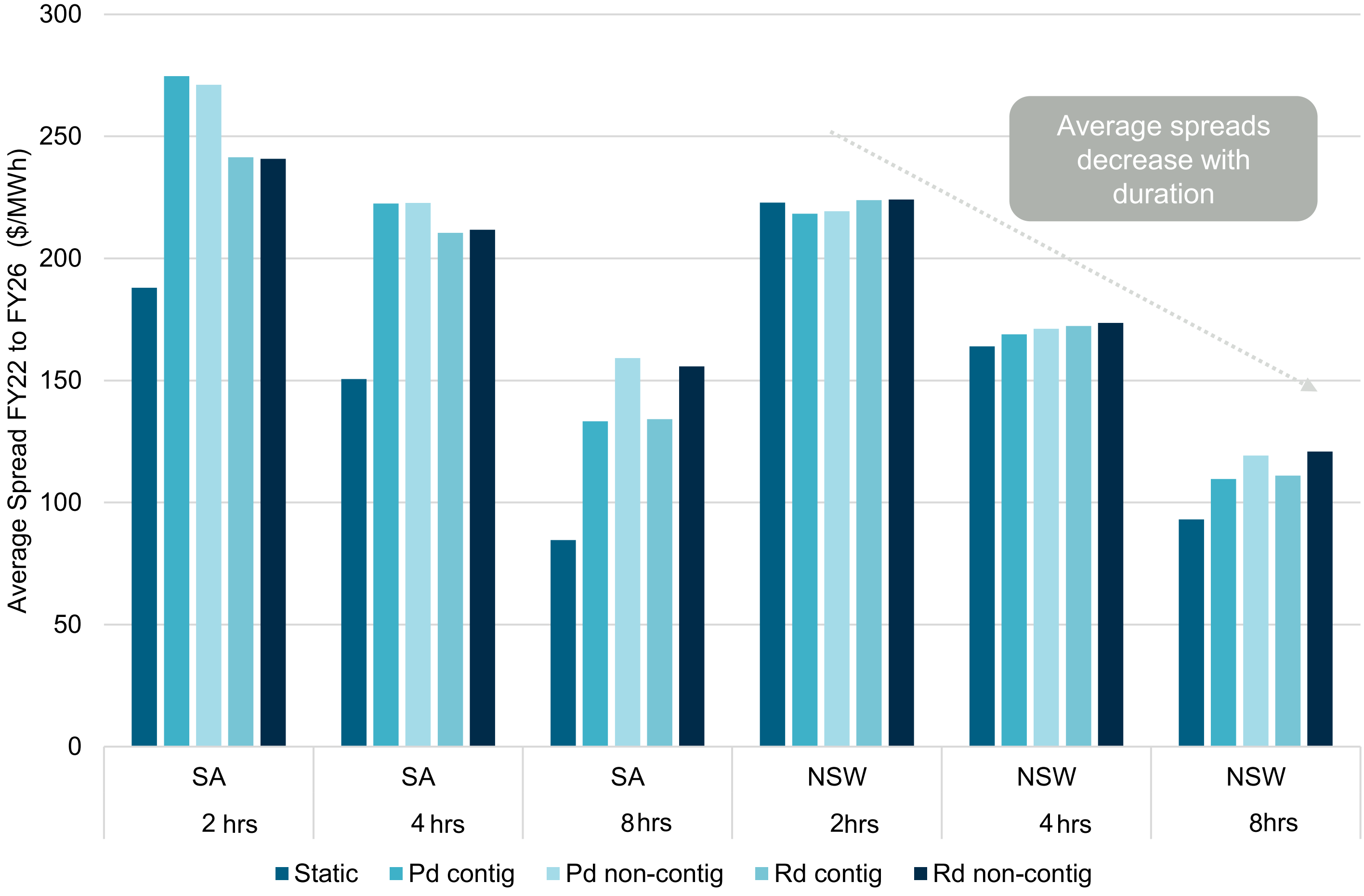
2. Historical Analysis – Spreads by Duration

- ASL has assessed the impact of duration for each of the spread options across 2,4 and 8 hrs over a five-year horizon for NSW and SA.
- As shown in the chart on the right, achieved spreads generally decrease with duration.
- In general, the static spread would have achieved a lower spread over the last five years than the other options, which is more evident in SA than NSW.
- The remaining spread options achieved relatively similar results and appear workable.

Figure: 5-Year Historical Achieved Spread by Duration (SA vs NSW)



3. Premium Estimate - Overview

ASL has undertaken analysis to **estimate required contract premiums for the purpose of contrasting against historical and forecast achieved spreads**. The below figures demonstrate the approach taken to build a high-level financial model that solves for required contract premiums. The model is derived from generic cost and financing assumptions and is a simplified view of how an actual project may use this product within their revenue stack.

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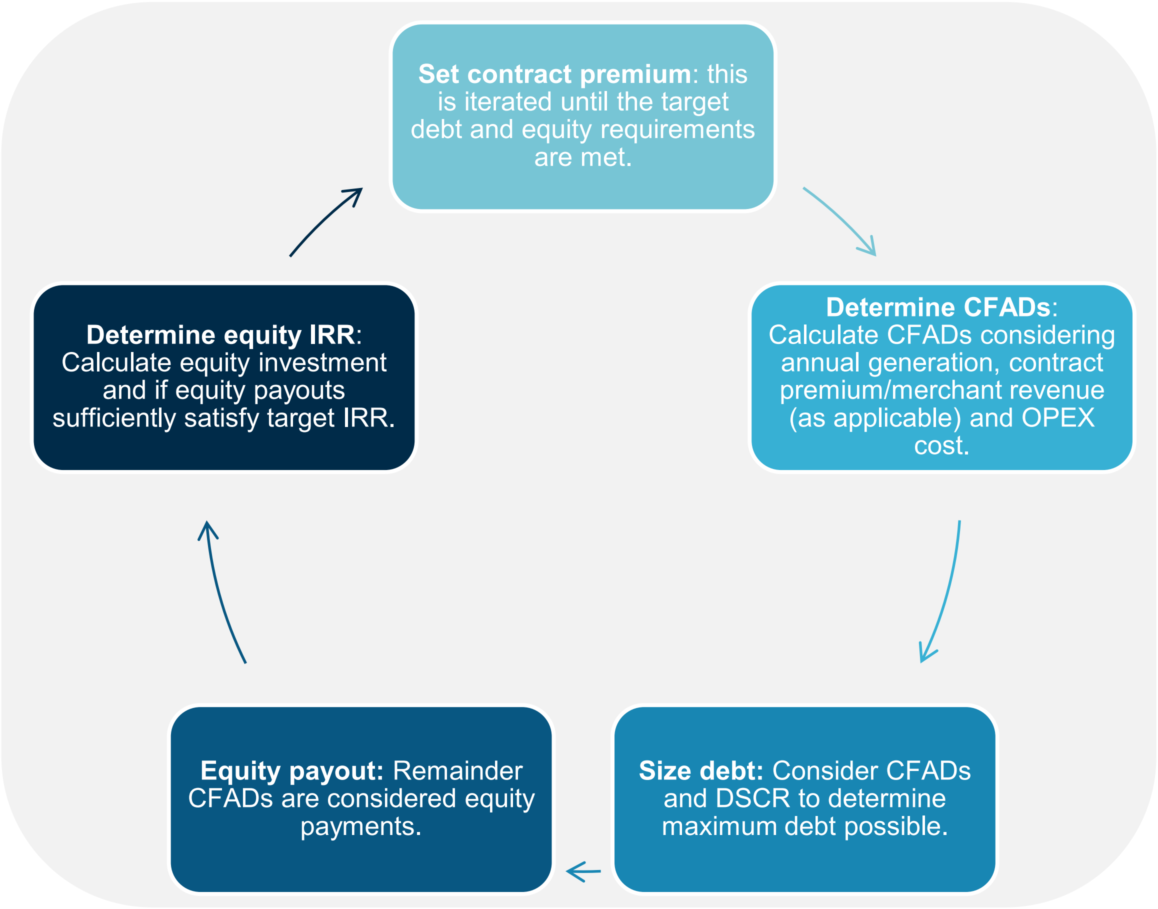
Figure: High-level modelling approach



3. Premium Estimate – Key Assumptions

Some of the key assumptions used to estimate the contract premiums are summarised below. Three scenarios were modelled based on a variety of possible contracted and merchant revenue scenarios to test the impact of different approaches.

Table: Key modelling assumptions

Quantity	Value	Source
All in Debt Interest Rate	6.55 to 7.65 %	SME Assumption
Equity IRR - Contracted	10 %	SME Assumption
Equity IRR – Merchant	15 %	SME Assumption
Contracted DSCR	1.25	SME Assumption
Merchant DSCR	2.0	SME Assumption
Notional Debt Tenor	18 years	SME Assumption
BESS Capacity	100 MW	SME Assumption
BESS Storage Duration	2 to 8 hours	SME Assumption
Project Life	25 years	SME Assumption
CAPEX*	915 to 2081 $/kW	AEMO ISP IASR 2026
Fixed O&M**	13.54 to 37.98 $/kW/year	AEMO ISP IASR 2026

*CAPEX is comprised of build cost, locational factor, auxiliary load and connection costs. This will vary depending on location and BESS storage duration. The above range is for a BESS in either central SA or central NSW with a storage duration of either 2, 4 or 8 hours.
**Fixed O&M dependant on BESS storage duration. The above range is for a BESS with a storage duration of either 2, 4 or 8 hours.

Other model simplifications:

- Near perfect foresight into market prices and operational philosophy to defend the contract spread has been assumed (e.g. no co-optimisation against ancillary services or other markets).
- MLF and Congestion has not been modelled.

Table: Modelling scenarios

Scenario	Years 1 to 4	Years 5 to 19	Years 20+
1	100% contracted	100% contracted	100% merchant
2	70% contracted, 30% merchant	70% contracted, 30% merchant	100% merchant
3	100% merchant	100% contracted	100% merchant

3. Premium Estimate - Findings

- The model estimates that a 4hr BESS may require a contract premium of ~ $95-135/MWh. A 2 hrs BESS is estimated to require a significantly higher premium of ~ $180/MWh, with 8hr BESS estimated to require a premium of ~ $100/MWh.

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Figure: Estimated Contract Premium by Scenario

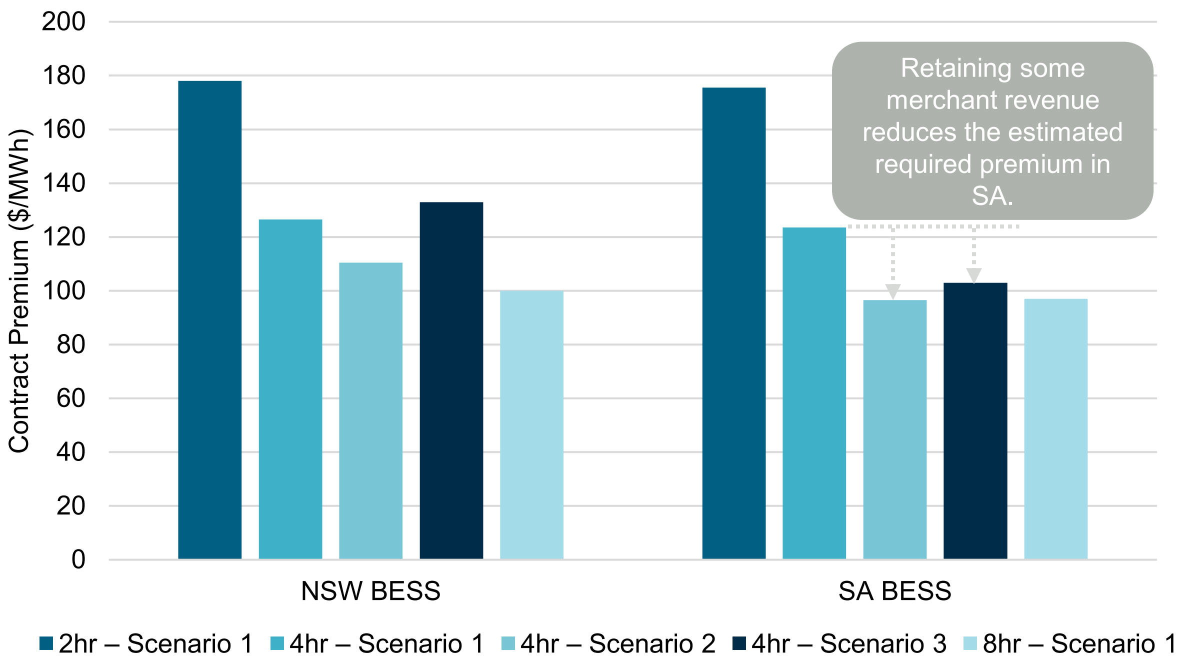

Table: Modelling scenarios

Scenario	Years 1 to 4	Years 5 to 19	Years 20+
1	100% contracted	100% contracted	100% merchant
2	70% contracted, 30% merchant	70% contracted, 30% merchant	100% merchant
3	100% merchant	100% contracted	100% merchant

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3. Premium Estimate - Findings

- The historical achieved spreads in SA are significantly higher than the estimated premiums for the last four years, indicating that the product may be of value both to the seller and the buyer. The graph does show, however, that there may be a gap between the estimated required premium and achieved spreads in lower volatility years.

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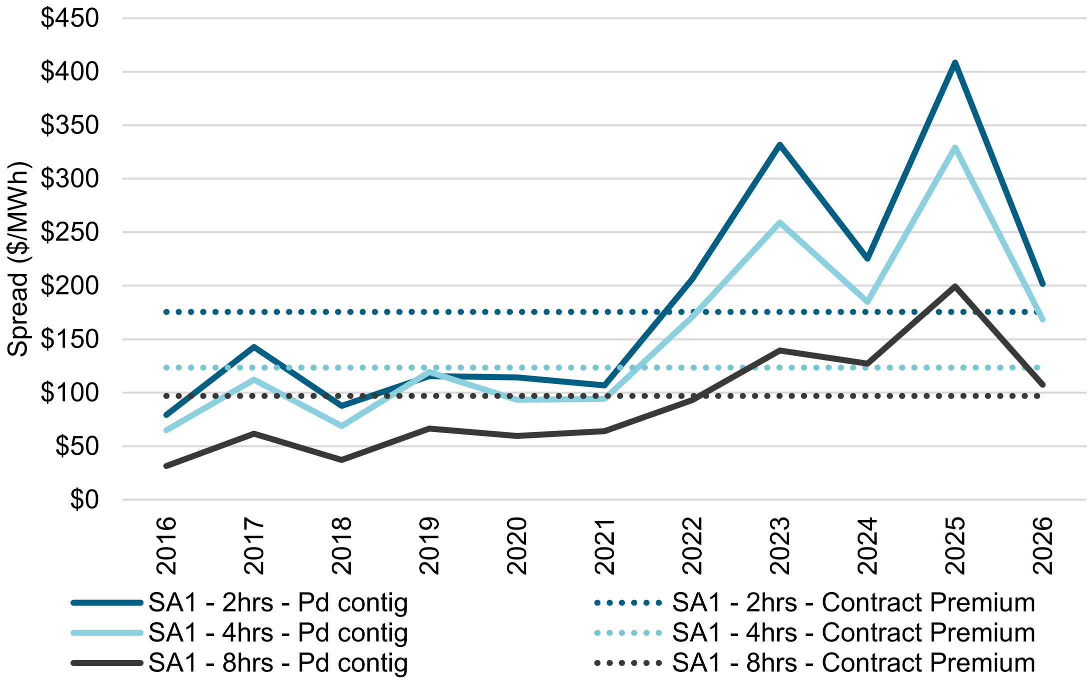
Figure: Estimated Contract Premiums vs Historical Achieved Spreads



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4. Risk Analysis - Overview

To support the Working Group in quantifying the impact of various downside/risks scenarios, ASL has analysed historical data to help quantify the net cash-flow impact of several identified risks as summarised below. The analysis assumes that 100% of the project capacity is contracted.

Table: Identified risks for analysis

Scenario	What are we testing	Approach per historical financial year
1. Short term outage for 1 week	• An isolated short-term (1 week) outage of 100% of the project capacity that coincides with a high price event.	• Identify highest average 1 week spread (worst case for defending shape and settling contract). • Determine contract settlement amounts during this week. • Quantify projects cashflow in this week and over the quarter.
2. Minor plant outage – 10% reduction in capacity for sustained 6-month period	• Plant has a failure/fault that results in a reduction in capacity for 6 months.	• Identify highest rolling 6-month price spread. • Derate plant by 10% and determine project cashflows over this time (project settles contract at 100% capacity, but only gets 90% of the wholesale revenue).
3. Major plant outage – 50% reduction in capacity for sustained 6-month period	• As above for a 50% de-rating, reflecting a major failure / outage.	• As above, increase derating to 50%.

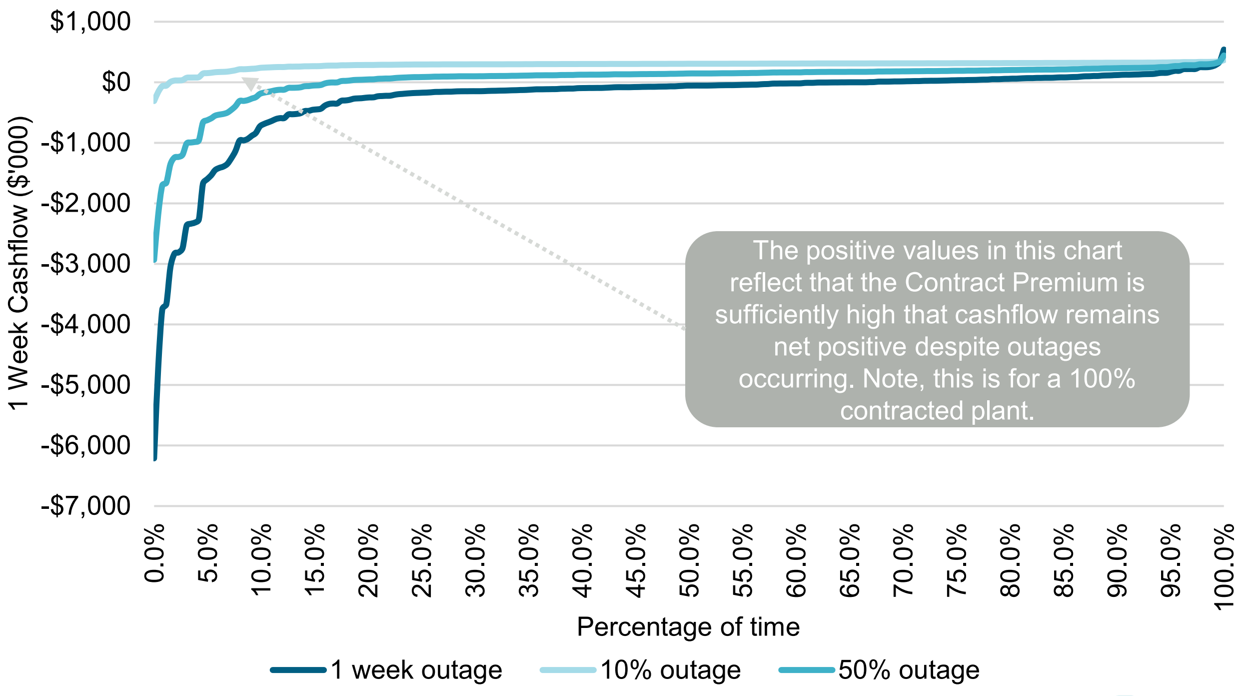
4. Risk Analysis - Findings

- The following analysis has been conducted on a contract unit of 100 MW and contract hours of 4 hours in SA.
- **The left table shows the worst 1-week net cashflow** experienced under each outage scenario. This **represents the worst-case scenario** in any given week (7-day rolling period) the seller would be liable for (positive values means a net-positive cashflow).
- Historical analysis shows a 1-week net cashflow impact of up to -$6.2m in the short-term outage scenario.
- **The right chart shows the frequency of cashflows** assuming a short-term or 10% or 50% outage occurs in every week. This **analysis demonstrates that 1-week outage could have a range of impacts**, with cashflows worse than -$1m/week being very rare.

Table: Worst 1 Week Cashflow (100MW, 4hr BESS (SA))

	Worst 1 Week Cashflow		
FY	Short term outage – 1 week outage	Minor plant outage – 10% reduction	Major plant outage – 50% reduction
2016	-$ 0.38m	$ 0.27m	-$ 0.02m
2017	-$ 4.35m	-$ 0.12m	-$ 2.00m
2018	-$ 2.28m	$ 0.08m	-$ 0.97m
2019	-$ 5.54m	-$ 0.24m	-$ 2.60m
2020	-$ 1.77m	$ 0.13m	-$ 0.71m
2021	-$ 1.80m	$ 0.13m	-$ 0.73m
2022	-$ 2.32m	$ 0.08m	-$ 0.99m
2023	-$ 2.83m	$ 0.03m	-$ 1.24m
2024	-$ 3.06m	$ 0.01m	-$ 1.36m
2025	-$ 6.21m	-$ 0.31m	-$ 2.93m
2026	-$ 4.73m	-$ 0.16m	-$ 2.19m

Figure: Cashflow Frequency 2022 to 2026



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4. Risk Analysis – Findings

- Both charts demonstrate cashflow impacts of scenarios 1 and 3 in further detail.
- In **the left chart, the short-term outage occurs in the week with the highest spread in 2025**. The significant spot exposure during this week results in a negative cumulative cashflow for the quarter and an inability to meet quarterly debt payments.
- In the **right chart, the seller is assumed to have a 50% outage across Q1 and Q2**. The project cash-flow is significantly lower in Q1 than Q2 due to spot price exposure during this quarter. In both quarters, the project is unable to generate sufficient revenue to meet its quarterly debt payment.

Figure: Cashflow Q1 2025 (Short term 1 week outage)

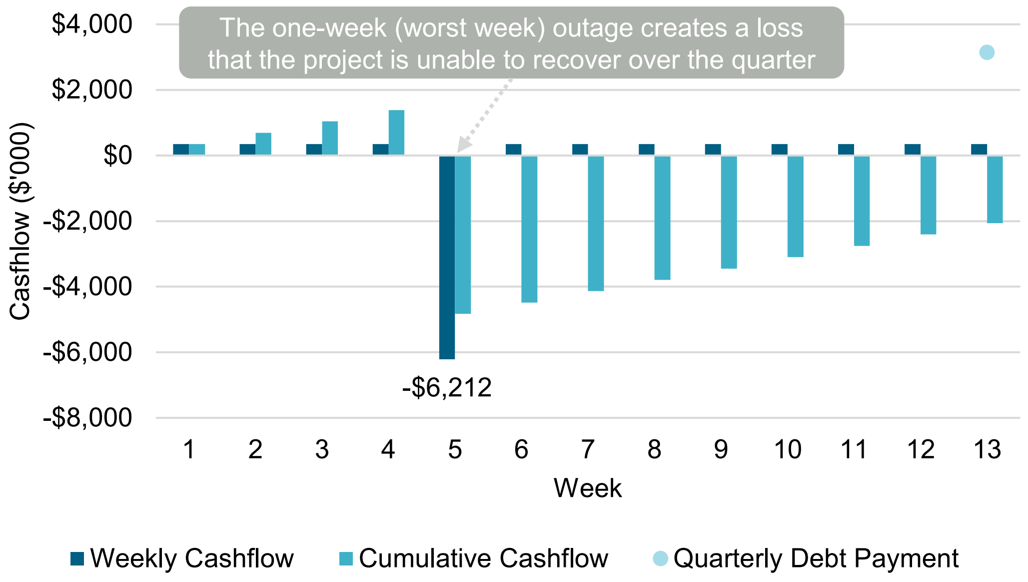
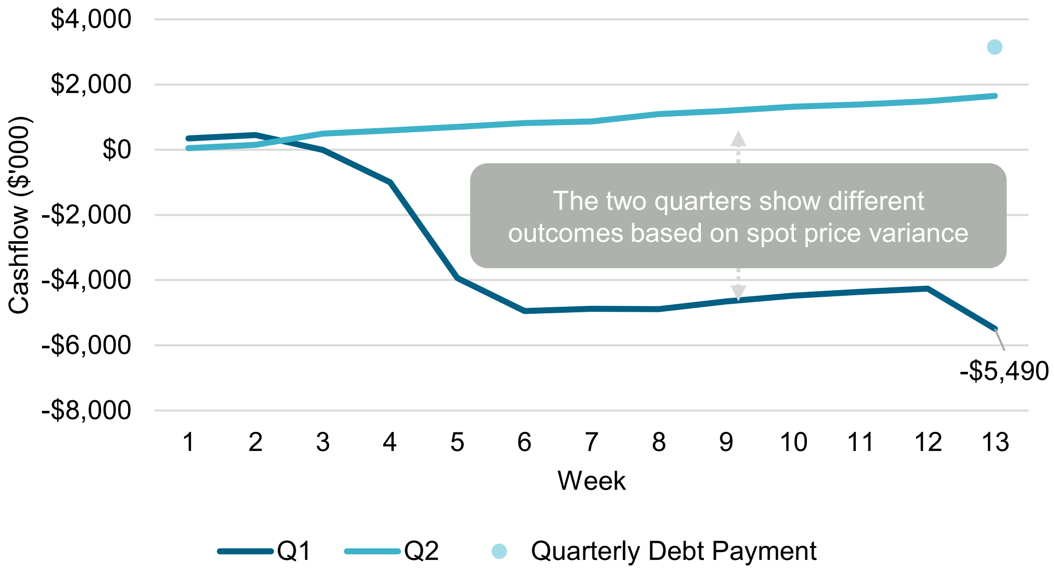


Figure: Cumulative Cashflow vs Debt Payment (Q1 and Q2, 2025 - 6 month 50% outage)



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4. Risk Analysis – DSCR impact

- The chart (right) shows the impact of the three identified risks on the quarterly DSCR of the project, in a scenario where the identified risks occurs each quarter.
- The timing of the outage can alter the impacts on DSCR significantly, and DSCR is relatively sensitive to these risks.
- Mitigations that could be implemented to reduce this sensitivity include:
    - Implementing a cash reserve (which may increase the premium).
    - Decrease contracted % to decrease contract exposure during outages (which may impact the premium).
- The estimated modest impact of implementing a cash reserve equal to 5% or 10% of CAPEX on estimated premiums is shown in the table (right).

Figure: Quarterly DSCR Under Risk Scenarios

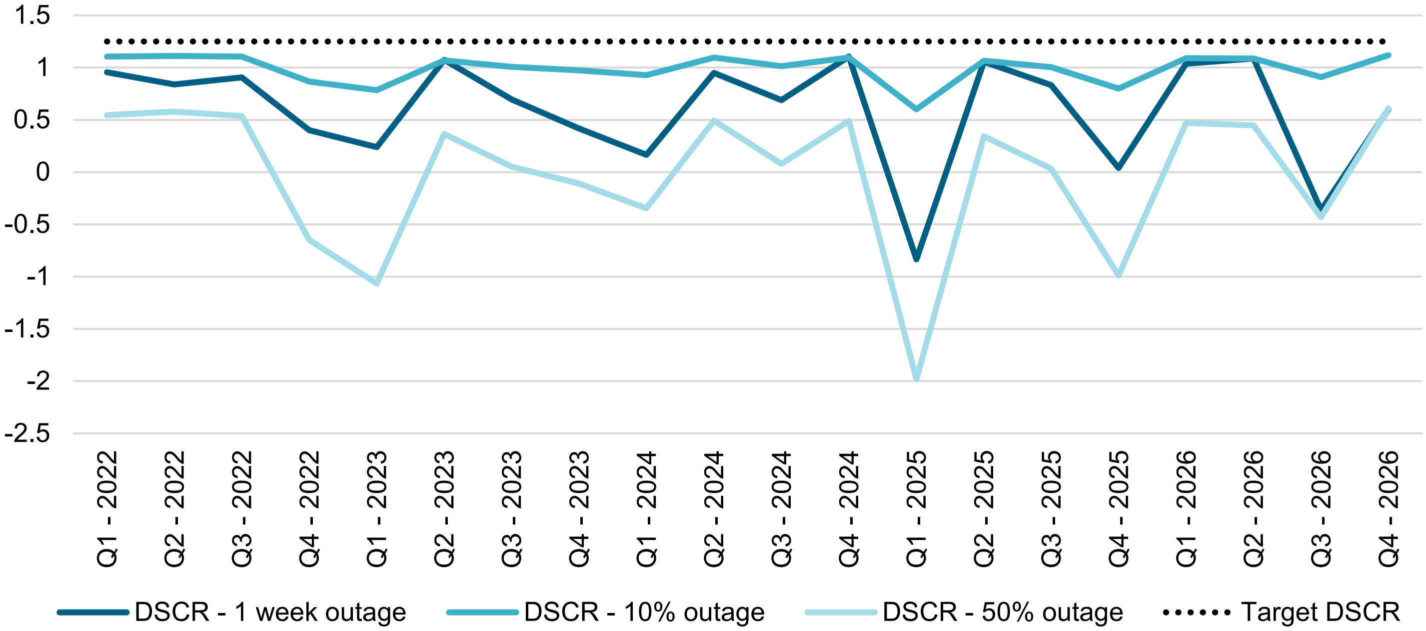

Table: Impact of cash reserve (100MW, 4hr BESS (SA))

Proposed cash reserve	Increase to estimated premium (100% contracted)	Estimated premium (70% contracted)
5% of CAPEX (~$6m)	$128.5/MWh ($5/MWh increase)	$103.5/MWh ($7/MWh increase)
10% of CAPEX (~$12m)	$133/MWh ($9.5/MWh increase)	$110.5/MWh ($14/MWh increase)

ing Analysis
Product Overview
Historical Analysis
Premium Estimates
Risk Analysis

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Summary of Key Findings

ASL's historical and forward-looking analysis into the shaping product found the following:

Historical Analysis

- Historical data showed that **daily spreads have generally increased over time**, across all identified nomination options. However, there was a sharp reduction in 2026.
- **Static time blocks would have achieved lower spreads than dynamically set pre-dispatch and residual demand block spreads** over the last five years.
- Over the same period, the **contiguous blocks would have achieved a marginally lower spread than non-contiguous blocks, but are significantly easier to define and operationalise**. For this reason, the pre-dispatch or residual demand contiguous block spreads appear favourable.

Premium Estimates

- **A contract premium[1] of around $95-135/MWh may be required for a new-entrant 4hr BESS**.
- This required contract premium is **lower than the 4hr realised spreads (~ $210-220/MWh in SA and ~$170/MWh in NSW) over the last 5 years, indicating contracts should have been valuable for buyers over this period**.

Information or conclusions relating to confidential forward price curves have been redacted for publishing

Risk Analysis

- Analysis determined the potential order of magnitude cash-flow impacts of short-term outages, sustained minor outages and a sustained major outage.
- The results show that **a sustained major plant outage or a complete short-term outage coinciding with high price events could present a significant risk under a shaping contract.**
- The WG should consider how the project seller could mitigate, including:
  - Retaining a cash reserve.
  - Buying back the position from the market.
  - Business continuity (or similar) insurance.

[1] The required contract premium is representative of the cost of new entrant generation.

Firming

These slides were used as a basis for discussion around risk allocation and key terms. Please refer to the provided minutes and draft product sheets for latest positions.

1. Product Overview – Cap Contract

A cap contracts provides:

- **A buyer** with reduced exposure to volatility in exchange for a fixed contract price.
- **A seller** with stable cash-flows from the contract price, in return for capping wholesale costs for the buyer at the strike price (e.g. $600/MWh).
- The **seller is not required to physically defend the cap**, although it's likely this would be mandated by lenders.
- The **seller should consider MLF losses and curtailment** in setting their contract price (seller retains MLF).

Table: Key Settlement Terms

Key Term	Description
Floating Price (FP)	The Spot Price (in $/MWh) set by AEMO for a Trading Interval at the Regional Reference Node.
Strike Price ($/MWh)	The Floating Price ($/MWh) above which cap repayments occur. (e.g. $600/MWh)
Contract Price ($/MW)	The agreed price ($/MW) for the cap contract paid by the buyer.
Contract Capacity (MW)	The contracted capacity per Contract Hours in the Settlement Period (flat shape).
Calculation Period	The Calculation Period will be aligned to the AEMO NEM settlement calendar (options include weekly, fortnightly, monthly or quarterly).
Notional Quantity (MWh)	The quantity of electricity (MWh) that applies for the Calculation Period. $Notional\ Quantity = Contract\ Capacity \times Calculation\ Period$
Contract Premium ($)	$Contract\ Premium = Notional\ Quantity \times Contract\ Price$
Cap Repayment Amount ($)	$Cap\ Repayment\ Amount = Notional\ Quantity \times \frac{(A-(Strike\ Price \times B))}{C}$, where: • A = the sum of all Floating Prices for the Region in the Calculation Period greater than the Strike Price ($/MWh). • B = the total number of trading intervals in the Calculation Period where the Floating Price for the Region was greater than the Strike Price. • C = the total number of trading intervals for the Region in the Calculation Period

These slides were used as a basis for discussion around risk allocation and key terms. Please refer to the provided minutes and draft product sheets for latest positions.

Settlement Risk Allocation - Firming

Contract Structure	Risk to Seller	Value to Buyer
Volume	• The seller holds the risk of defending the agreed volume of the cap (capacity x hours).	• The contract volume is fixed and hence the buyer is not exposed to volume risk.
Price	• The seller receives a fixed premium, regardless of wholesale prices. • The seller is exposed to prices below the cap.	• The buyer pays a fixed Contract Premium and hence is not exposed to price risk for the agreed volume above the cap. • The buyer is also exposed to prices below the cap.
Shape	• The seller must be able to defend the cap for all high price events above the strike price	• The buyer is protected from all high price events above the strike price

1. Product Overview – Settlement Examples

The below table shows cap contract net revenue for different wholesale market prices, assuming a contract price of $30/MWh, a contract unit of 1MW and a gas turbine short-run marginal cost (SRMC) of $220/MWh.

A gas turbine would typically run in two scenarios:

- **Merchant:** where the floating price (FP) is greater than SRMC but less than the strike price and it is exposed to the floating price.
- **Cap Defending:** where the floating price is greater than the strike price and the project is defending against cap exposure.

In the simplified example below, the same contract price is used for $300 and $600 caps. In practice, a higher strike price means the product may be less valuable to the buyer as a result would likely attract a lower contract price.

Table: Settlement Examples

	Wholesale Revenue			$300 Cap			$600 Cap		
	FP ($/MWh)	**Generation Volume (MWh)**	**Wholesale Revenue ($)** *(FP*Vol)*	**Contract Revenue ($/MWh)** *(Volume* Contract Price)*	**Cap Repayment Amount** *(-MAX(0,FP-$300))*	**Net Revenue** *(Wholesale Revenue + Contract Price - Cap Contract Payout)*	**Contract Revenue ($/MWh)** *(Volume* Contract Price)*	**Cap Repayment Amount** *(-MAX(0,FP-$300))*	**Net Revenue** *(Wholesale Revenue + Contract Price - Cap Contract Payout)*
Merchant Running	**$150** (FP < SRMC)	0MWh	$0	$30	$0	$30	$30	$0	$30
	$250 (SRMC < FP < Strike)	1MWh	$250	$30	$0	$280	$30	$0	$280
Cap Defending	**$500** (Strike < FP)	1MWh	$500	$30	-$200	$330	$30	$0	$530
	$1000 (Strike < FP)	1MWh	$1000	$30	-$700	$330	$30	-$400	$630

Analysis Overview

Firming Product

1.

Provide an overview of the proposed product and settlement mechanics

2.

Analyse historical data to determine fair value pricing for cap contract prices

3.

Estimate contract prices required for a new entrant gas turbine

4.

Assess identified bankability risks

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2. Historical Analysis – Findings

- ASL has analysed historical data to review trends related to the fair price value of $300 and $600 cap contracts over the last 10 years.
- Fair cap prices were calculated by determining the contract price ($/MWh) which equals the cap repayments over a particular period.
- E.g. in FYE 2017 the fair cap price in SA would have been $31/MWh. Meaning that in 2017 the total payments from the project to the buyer would have been *$31*365(days)*24(hours) = $271,560* per MW contracted.
- The analysis shows the volatility in fair cap prices both annually (upper right) and seasonally (lower right).
- Fair cap prices vary significantly in different states, for instance SA has roughly twice the fair cap price over the last 10 years than VIC.

Figure: Historical Annual Fair Cap Price by FY ($300 Strike)

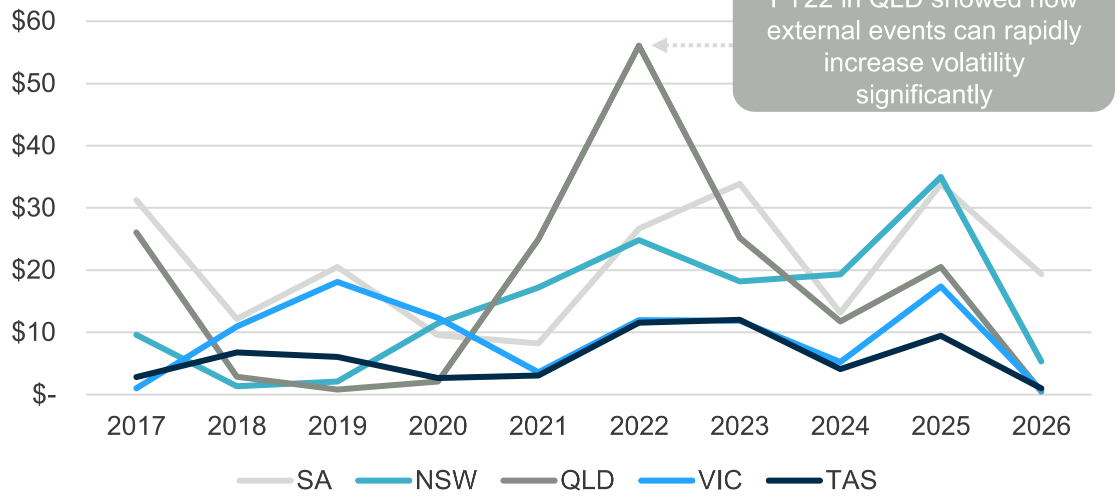

Figure: Historical Quarterly Fair Cap Price by FY ($300 Strike)

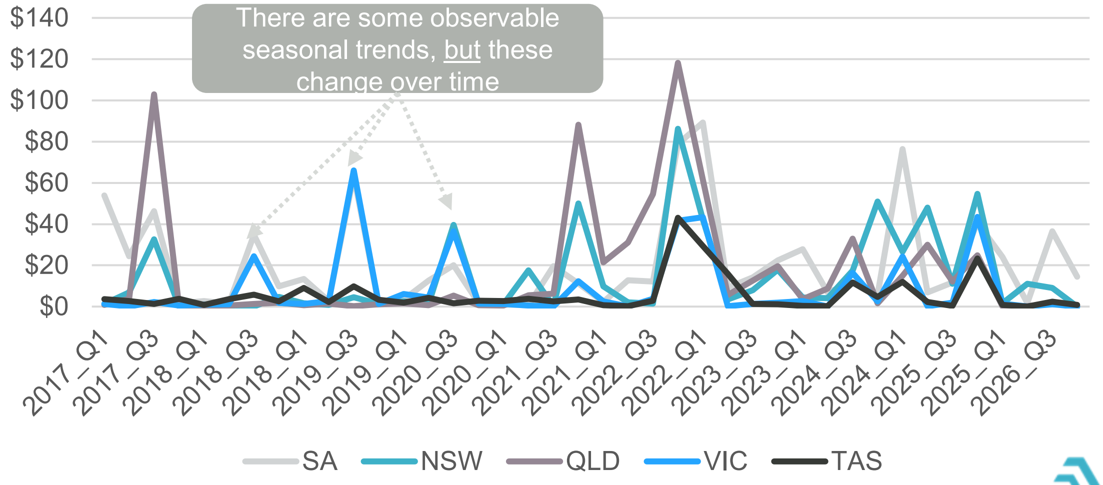

Table: 10-Year Average Fair Value Cap Prices

	SA	NSW	QLD	VIC	TAS
$300 Cap	$ 20.9	$ 14.4	$ 17.1	$ 9.3	$ 6.0
$600 Cap	$ 16.3	$ 10.8	$ 13.3	$ 6.1	$ 3.6

ng Analysis | Product Overview | Historical Analysis | Contract Price Estimates | Risk Analysis

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2. Historical Analysis – Findings

- The fair cap price for a $600 cap over the last 10 years is lower than a $300 cap (as expected), however, the difference varies significantly by year and state. In some years, such as 2025 and 2026, there is minimal difference whereas in 2022 and 2023 it can be more than twice the value.
- The historical analysis (upper, right) does not indicate a close coupling between total volatility and the relationship between $300 and $600 strike prices, reflecting that volatility can be driven by sustained moderate prices (e.g. $350) or extreme short duration events, which each alter the fair value price of $300 and $600 caps differently.
- The 10-year average of value of $600 cap versus the $300 cap (lower, right) demonstrates a convergence of trends across states, with the fair value of $600 caps between 60-80% of $300 caps over this period.

Figure: Historical Fair Cap Price by FY for Difference Strikes (NSW, SA)

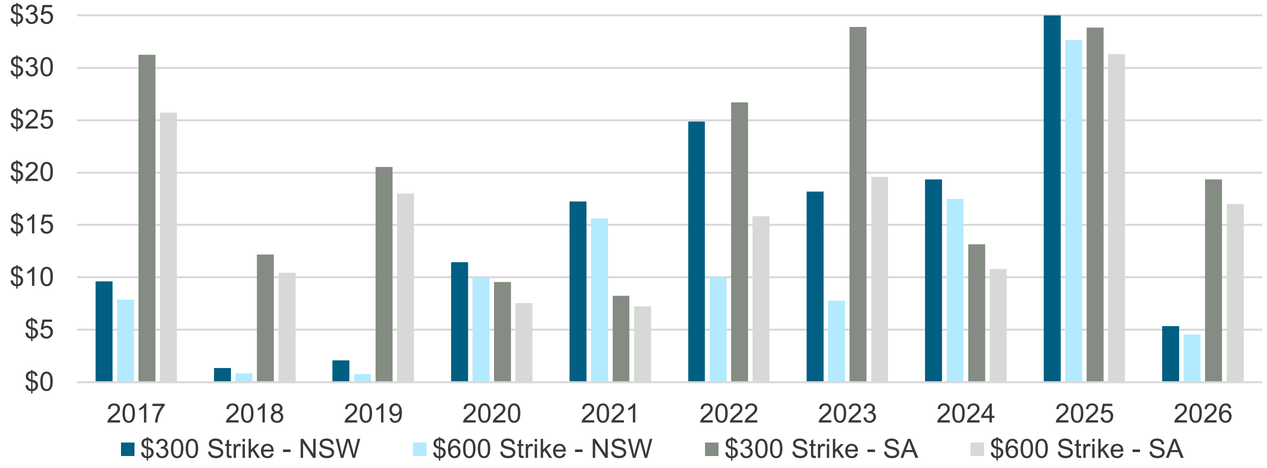

Figure: Percentage Value of $600 cap versus $300 cap, 10 Year Average

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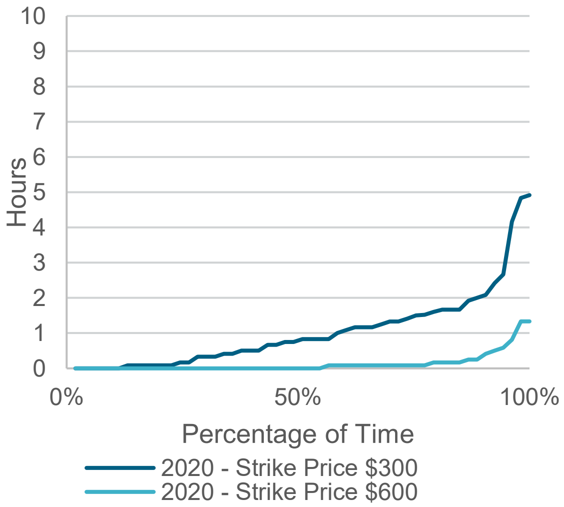
2. Historical Analysis – Findings

- ASL has investigated two historical (calendar) years 2020 (low volatility) and 2022 (high volatility – and the year where AEMO suspended the market temporarily), to assess the theoretical impact on gas turbine utilisation.
- The plots show the distribution of the hours prices were above $300 and $600 in a week to demonstrate theoretical running hours to defend a cap. Note this utilises data from *all* states in one chart.
- 2020 had very low hours of high prices in any given week, with a theoretical maximum of 5 hours of running required to defend the cap a week.
- 2022 had significantly higher frequency of high prices, with a theoretical maximum of over 140 hours of running required to defend the $300 cap in a week.
- The higher the number of hours required in a particular week the greater the risk fuel networks may experience strain and that local storage (if any) may be depleted.

- ASL has calculated the distribution of theoretical cap repayments (by performing a back cast) for a 265MW gas turbine that was fully contracted via cap contracts over the last five years for both $300 and $600 caps for NSW and SA.
- The plot is based on an analysis of the last 5 years of historical prices. It determines the cap repayments that a 100% contracted 265 MW gas turbine would have been liable to pay in each week within the year.
- Cap repayments are greater than $0 significantly more frequently in SA when compared to NSW due to price volatility in the state.
- Additionally, the $600 Cap has historically not required defending for 40% of weeks in SA and 50% of weeks in NSW.
- In comparison to the risk analysis in later pages, the graph below represents the gross cap repayment only and does not consider the contract price and wholesale revenue earned.

Figure: Distribution of cap defending run time hours per week 2020 (L) and 2022 (R)



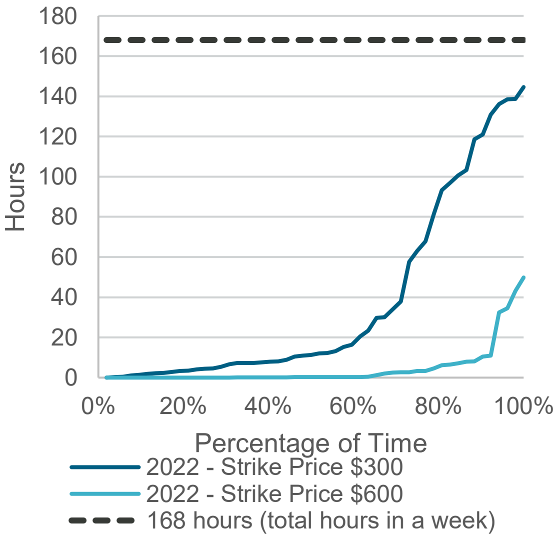
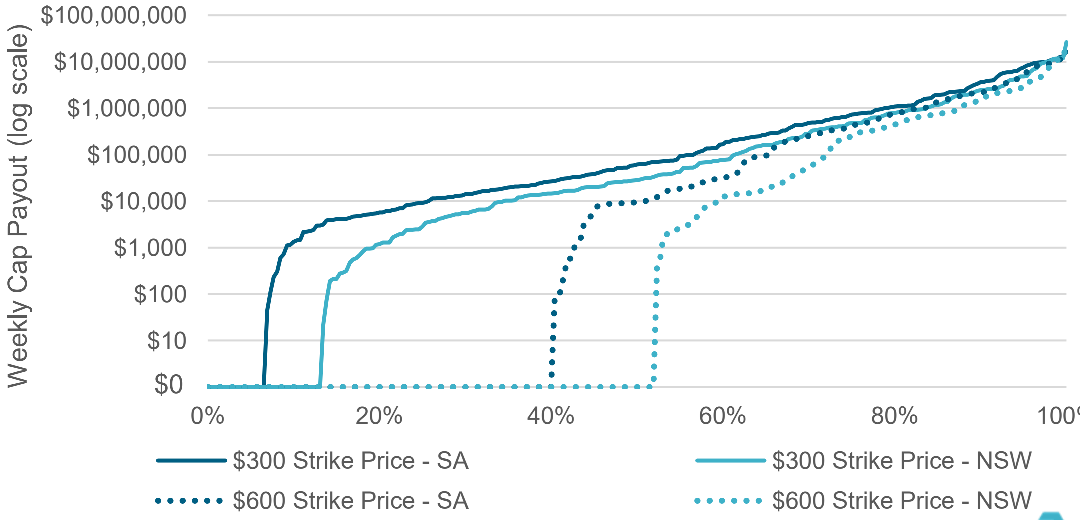


Figure: Weekly theoretical cap repayments distribution (265MW GT)

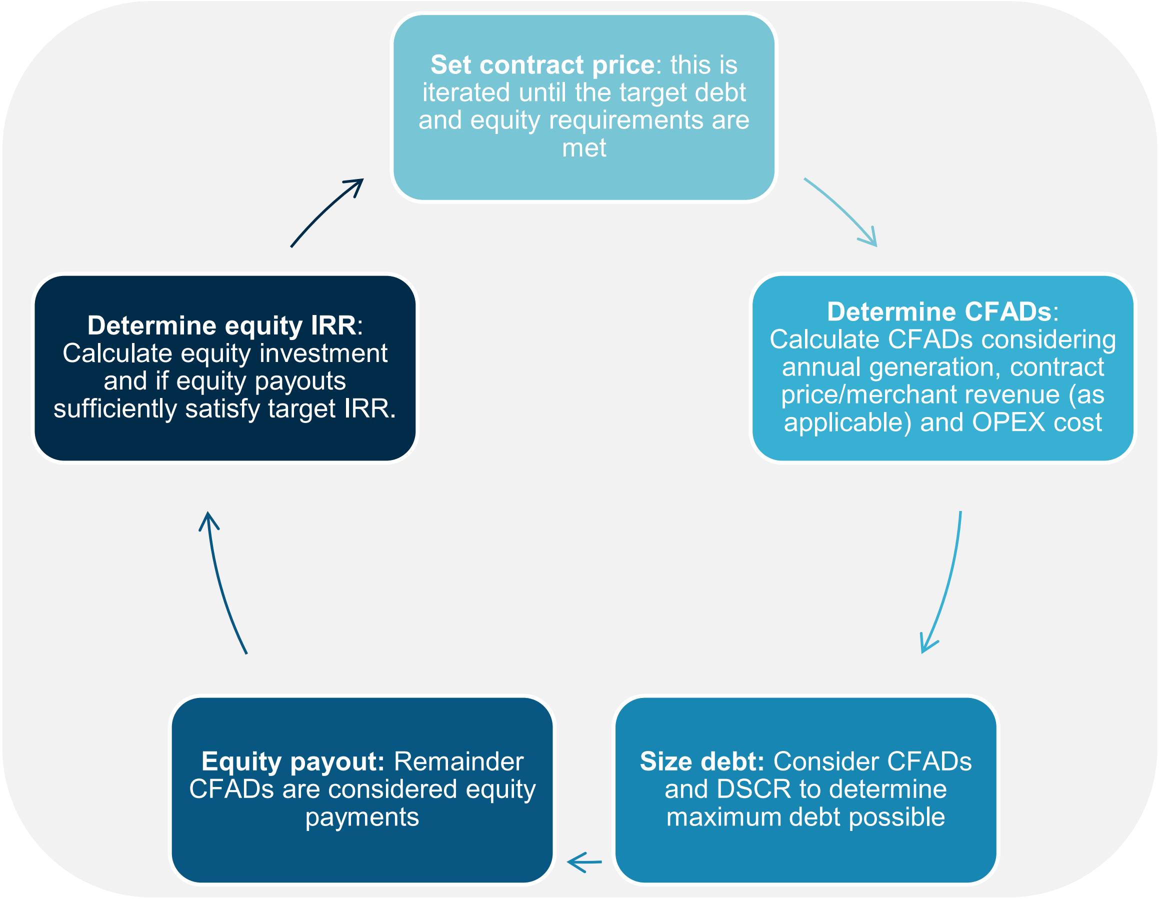


3. Contract Price Estimate - Overview

ASL has undertaken analysis to **estimate required contract prices to contrast against historical values**. The below figures demonstrate the approach taken to build a high-level financial model that solves for required contract prices. The model is derived from generic cost and financing assumptions and is a simplified view of how an actual project may use this product within their revenue stack.

Information or conclusions relating to confidential forward price curves have been redacted for publishing

Figure: High-level modelling approach



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3. Contract Price Estimate - Assumptions

Some of the key assumptions used to estimate the contract prices are summarised below. Four scenarios were modelled based on a variety of possible contracted and merchant revenue scenarios to test the impact of different approaches.

Table: Key modelling assumptions

Quantity	Value	Source
Gas Turbine Size	265 MW	AEMO ISP IASR 2026
Project Life	25 years	AEMO ISP IASR 2026
Debt Interest Rate	6.55 %	SME Assumption
Equity IRR - Contracted	10 %	SME Assumption
Equity IRR – Merchant	15 %	SME Assumption
Heat Rate	10.93 GJ/MWh	AEMO ISP IASR 2026 (SESA OCGT Large)
Fuel Cost	$20/GJ	SME Assumption
Build Cost*	$1,743 $/kW	AEMO ISP IASR 2026, 2025-26 Step Change
Build Cost Capex Multiplier	1.3	SME Assumption
Connection Cost	132 $/kW	AEMO ISP IASR 2026 (SESA OCGT Large)
Variable O&M	$9/MWh	AEMO ISP IASR 2026 (SESA OCGT Large)
Fixed O&M	$15,758/MW/year	AEMO ISP IASR 2026 (SESA OCGT Large)
Contracted DSCR	1.25	SME Assumption
Merchant DSCR	2.0	SME Assumption

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Note: * Build cost estimates for new entrant gas turbines are highly indicative due to limited data on actual build costs within the NEM.

Other Model Assumptions:

- Ramp rate limitations have not been factored in
- Perfect foresight into market prices and operational philosophy to maximise wholesale and contract revenues has been assumed (e.g. no co-optimisation against ancillary services or other markets).
- MLF and Congestion has not been modelled.

Table: Modelling scenarios

Scenario	Contracted Percentage	Strike Price
Scenario 1	100%	$300
Scenario 2	100%	$600
Scenario 3	70%	$300
Scenario 4	70%	$600

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3. Contract Price Estimate – Forward Curves

Information or conclusions relating to confidential forward price curves have been redacted for publishing

3. Contract Price Estimate - Results

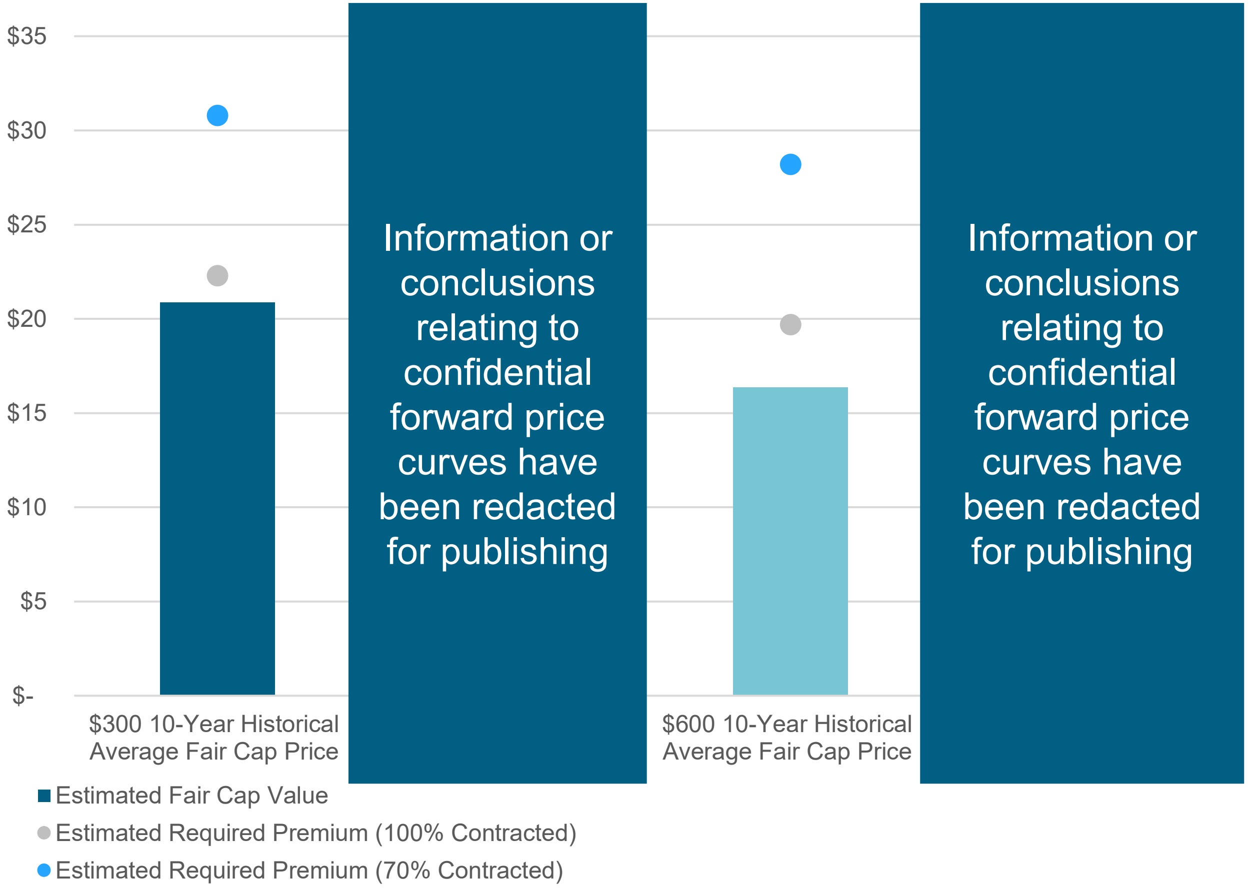
- The estimated contract prices for the four scenarios are shown in the chart to the right.
- $600 Strike Price contract prices are lower across all scenario due to the project capturing greater wholesale revenue.
- The plot shows that in the case where the project is 70% contracted (and therefore 30% merchant) the required contract price is significantly higher for both $300 and $600 caps. This is driven by a combination of factors, including the higher DSCR and equity IRR assumed to be required for merchant revenues.
- The plot also presents the average historical and forecast 10-year fair cap prices. The historical average is not significantly lower than the 100% contracted scenario for either the $300 or $600 caps.

Information or conclusions relating to confidential forward price curves have been redacted for publishing

- When compared to other states, SA has the highest historical fair cap prices.

Information or conclusions relating to confidential forward price curves have been redacted for publishing

Figure: Estimated Required Contract Prices against Historical and Forecast Fair Value Cap Prices (SA)



4. Risk Analysis - Overview

To support the Working Group in quantifying the impact of various downside/risks scenarios, ASL has analysed historical data to help quantify the impact of several identified risks as summarised below. For each of the downside scenarios, ASL has also constructed a 'theoretical worst case' scenario to further provide some quantitative data to support assessment of the bankability risks from cap contracts.

For each of the identified risks, ASL calculated the net revenue as cap contract price (assumed at $30/MWh) minus wholesale revenue and cap payouts.

Table: Identified risks for analysis

Scenario	What are we testing	Approach (historical)	Approach (theoretical)
1. Short term outage for 1 week	• An isolated short-term (1 week) outage of 100% of the project capacity that coincides with an extreme price event	• ASL identified the historical week from last 10 years with the highest cap payout, which was identified as the week beginning 21/01/2019 in Victoria. • Determine contract settlement amounts during this week. • Quantify projects liability in this week.	• ASL developed a theoretical worse week of cap exposure, by considering a series of MPC (market price cap) events that results in administered pricing taking over. An alternate series of MPC events followed by APCs (administered price cap) will form the basis of this theoretical 'worst pricing period'. • Determine contract settlement amounts during this week. • Quantify projects liability in this week. • Assume $30 Cap Contract Price.
2. Minor plant outage – 10% reduction in capacity for sustained 6-month period	• Plant has a failure/fault that results in a reduction in capacity for 6 months	• ASL identified the 6-month period from last 10 years which would have had the highest cap payout. This was identified as the 6-months beginning 31/01/2022 in Queensland. • Derate plant by 10% and determine project cashflows over this time (project settles contract at 100% capacity, but only gets 90% of the wholesale revenue).	• ASL developed a theoretical worst 6 months of cap exposure, by a similar method to the 1-week outage, but for an extended period of time. The result is a series of MPC events followed by APC pricing until the 7-day rolling average is below the cumulative pricing threshold and then MPC events occur until once again APC pricing is implemented. • Derate plant by 10% and determine project cashflows over this time (project settles contract at 100% capacity, but only gets 90% of the wholesale revenue). • Assume $30 Cap Contract Price.
3. Major plant outage – 50% reduction in capacity for sustained 6-month period	• As above for a 50% de-rating, reflecting a major failure / outage.	• As above, increase derating to 50%.	• As above, increase derating to 50%.

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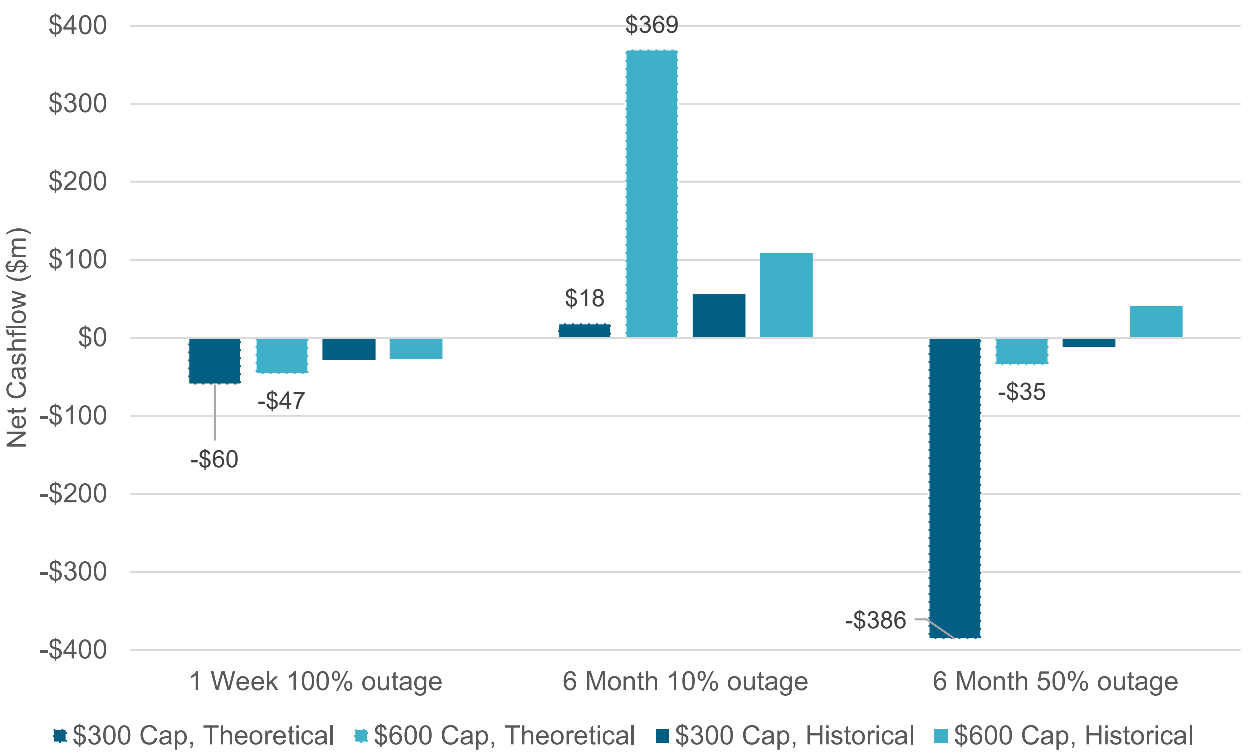
4. Risk Analysis - Results

- For the one-week complete outage of the theoretical 265MW gas turbine, a net cashflow of -$60m was calculated for the theoretical worse case and -$29m using historical data.
- For the 6-month minor plant outage (10% case) the net cashflow during volatile periods is positive, as the wholesale revenue obtained during the high price events offsets the portion of the cap that is not physically defended.
- For the major outage (50%), there is a large negative cashflow in the theoretical case as the contract exposure outweighs the wholesale revenue.
- For both the minor and major outages the theoretical worse case is significantly larger in magnitude than the historical case.
- Across the three scenarios tested, the $600 cap significantly reduces the impact of the events in comparison to the $300 cap.
- Mitigations that could be implemented to reduce this sensitivity include:
    - Implementing a cash reserve.
    - Increased margin within the contract price.
    - Decrease contracted % to decrease contract exposure during outages.
- Implementing a cash reserve of $60m for a 265 MW project (i.e. $226,000 / MW) to cover the modelled one-week outage is estimated to increase required contract prices by approximately 10%.

Figure: Bankability risk analysis results – 265 MW Gas Turbine



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Key Findings: Firming

ASL's historical and forward-looking analysis into the firming product found the following:

Historical Analysis

- **The historical fair value of cap contracts is extremely volatile.**
- Whilst there is some longer-term convergence in fair cap pricing across different states, **there is a divergence of volatility in shorter term horizons**.
- **The 10-year average historical 'fair value' of a $600 cap was found to be 20-40% lower than a $300 cap** (e.g. $16/MWh vs ~$21/MWh in SA) , indicating the value/cost of moderate volatility in the $300-$600 price bands.

Premium Estimates

- **A premium of ~$22-31/MWh for a $300 cap and ~$20-28MWh for a $600 cap** is estimated to be required for a new entrant gas turbine[1].
- The premium for a $600 cap is lower than the $300 cap due to the increased merchant revenue a project could obtain between $300-600.

Information or conclusions relating to confidential forward price curves have been redacted for publishing

Risk Analysis

- Analysis demonstrated the potential order of magnitude cash-flow impacts of short-term outages, sustained minor outages and a sustained major outage, using both 'theoretical' worse outcomes and selected worse historical weeks/six-month periods.
- The analysis showed that $600 strike has lower risk for the seller in comparison to the $300 cap and provides more opportunities to earn merchant revenue and reduce cash-flow impacts during potential FM events.

[1] **Premium estimates for new entrant gas turbines are highly indicative due to limited data on actual build costs within the NEM.**

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