Contingent Storage Management:

Understanding the trade-offs from restricting access to contingent hydro storage

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Final Summary Report - V2

20 September 2025

Disclaimer

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1

OBJECTIVE AND SUMMARY

Objective and summary conclusions of the study – part 1

Objectives and summary conclusions – Part 1

- **The objective of this study was to better understand the trade-offs from easing or restricting access to contingent hydro storage.**
  - **Security impacts (Unserved energy risks):**
    - Would we end up with less backup generation overall and so we are more susceptible to consecutive dry years/unplanned outages of other plant?
      - More restrictive access to CS would provide a larger amount of contingent storage reserve to cover multiple contingencies including a large unplanned outage of a thermal plant such as E3P.
      - A possible worst case includes the lowest winter inflows in the last 93 years (1932) combined with a six month outage of the E3P CCGT plant. Simulation suggests that the extra reserve would significantly reduce demand reduction costs in that event by around $440-750m in 2026, however this benefit would need to be balanced against the ongoing annual costs of around $20-40m/y of a more restrictive policy [⏩].
      - The value of this extra reserve is much higher over the next few years. It would be reduced if the 3rd Rankine unit was made available and fully fuelled, and will then decline further as new renewable plant is built and a new entry equilibrium is reached [⏩].
    - What would be the effect on thermal back-up generation capacity and fuel (if hydro generators have unrestricted access to CS)?
      - Unrestricted access to CS is likely to lower gross margins for the key thermal back-up generators by up to *$5-20/kW/y*. This is unlikely to impact E3P viability, or Huntly and the gas peakers in the scenario with 2 Rankine units.
      - However it may be enough to affect the viability of the 3rd Rankine unit, and may result in Huntly and gas peakers reducing stocks to save fuel holding costs. Reductions in stock levels would limit back-up generation in dry years, which might be mitigated by CS if it was available. [⏩]
    - Risk of thermals retiring earlier with unrestricted access to contingent storage
      - As we move towards an economic equilibrium the viability of the 3rd Rankine unit will reduce as gross margins fall below $100/kW/y. By this time the impact of easier access to CS reduces from $15/kW/y to less than $5/kW/y. This reduction will increase the risk of early retirement, but only marginally. [⏩]

Objective and summary conclusions of the study – part 2

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Objectives and summary conclusions – Part 2

- **Cost effects including impacts on prices and price volatility:**
  - What is the impact on total system costs (operational and investment)?
    - Restricting access to contingent storage could increase annual system cost by around $20-40m/yr depending on the degree of restriction and the system state. This annual cost arises from lake levels being held higher resulting in extra hydro spill which needs to be met by additional thermal fuel use. [⏩]
  - Would prices just rise again if thermals backup generation reduces (just get to a new equilibrium) but one that's less secure?
    - Restricting access to CS is likely to result in electricity prices being somewhat lower when lake levels are higher (due to higher risk of spill), but higher when lake levels are falling (due to a increase in the duration and cost of thermal backup). In very extreme rare situations (such as a double contingency) prices might be very much lower as there would be a larger amount of hydro storage available to reduce the risk of prices rising to reflect the increased risks/costs of shortage.
    - On average it is estimated that the impact of lowered prices will exceed the impact of prices rises, and so there should be a net decline of up to $4/MWh .
    - Even if prices don't fall when the risk of spill increases, and if double contingencies are ignored, then the maximum price increase is estimated to be $8-1/MWh. [⏩]
  - Would prices be more volatile as more renewables and potentially less thermal generation (if they do retire) means we can go from high storage to low storage pretty quickly if we low wind and solar months.
    - Unrestricted access to CS is likely to reduce the volatility in prices (i.e. make the price duration curve less steep) over normal weather year volatility.
    - However the reduction in the size of the CS reserve in double contingencies could significantly increase prices in these rare events. The worst of the worst downside price could be much larger [⏩]

- **Impact on new Investment:**
  - What would be the impact on new generation investment – would this get delayed?
    - Unrestricted access to CS can impact either the level of thermal fuel used (eg more coal or gas per year) or the level of new investment (ie bring forward extra renewables).
    - While we are in an economic disequilibrium, new investment in renewables is limited by supply constraints so fuel is impacted.
    - Once we get to an equilibrium then both will be impacted.
    - But the cost impact will be similar as the marginal costs of additional fuel will be equal to the marginal costs of new renewable supply. The quantities involved are very small (<30MW) and so the impact of any delay would be immaterial.

What have I done ..

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- **The aim is to model the "bookend" cases for restrictions on use of contingent storage ranging from very restricted to fully unrestricted.**
- **This is to be used to explore the issues associated with restricted access to contingent storage, including an intermediate case.**
- **I am using the same model from the NZ Battery modelling work, updated for new data.**
    - This simulates weekly over approx. 93 weather years, including demand uncertainty, plant and transmission outages etc.
    - Each week is modelled as 36 blocks (1 chronological workday by hour and 1 weekend day by 2 hr) or 168 hourly blocks.
    - All the main hydro reservoirs (with simplified energy-based inflows, generation, constraints etc).
    - Heuristic offer curves (as function of week in year and level) for major reservoirs, tuned to reflect reservoir limits and trade-off between spill and costs of fuel/demand response and shortage and frequency of using contingent storage.
    - Thermal offer structures derived from estimated fuel opportunity costs, with adjustments to capture minimum running, plant inflexibility and energy restrictions.
- **I have updated the model to use Transpower assumptions on demand, plant investment, fuel constraints, fuel costs, new entry costs etc.**
    - These generally reflect the latest Security of Supply Assessment (SOSA) assumptions.
- **I have carried out a back-cast for the 2024 year to check model performance versus reality.**
    - This showed a close match to lake levels over the critical winter period, and quite good matching to physical output for key categories of generation. Prices showed a reasonable match over the year but did not match the seasonal pattern as the very large variation of gas prices within the year was not modelled.
- **I have run 93 * 4 * 4 * 4 simulations**
  - **I ran the model by week/hour for 93 weather years for future systems in 2026, 2028, 2030 and 2035.**
  - **In each case I ran 4 scenarios : 2 and 3 Huntly Rankine units with and without coal constraints.**
  - **For each of these I simulated 4 policies for contingent storage use : Unrestricted, modUse, midUse, lowUse, Restricted.**
    - I have not explored the impact of normalization of the historical inflow data to reflect more recent patterns or adjustment for climate change in the future .
- **These provide quantitative bounds on the impact of alternative CS restriction scenarios.**
  - **The quantitative metrics include- impact on system cost (carbon, fuel, demand response, shortage risk and cost), price levels and volatility, the % of weeks in the contingent zone.**

Limitations

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- **This quantitative assessment is subject to a few limitations:**
  - **In most of these simulations the estimated cost savings are of the order $20-45m/y or 5-7% of total system fuel costs which is close to the margin of error.**
  - **This is error is partly mitigated by using a consistent approach to the modelling of “with” and “without” cases (e.g., through consistent weather assumptions).**
    - All modelling of market behaviour involves assumptions (heuristics) on how participants respond to changing and uncertain information.
    - This is inherently difficult.
      - Some modelers take an optimizing approach – which is based on a perfect coordination and cost minimization methodology.
        - While this has the advantage of being somewhat repeatable and consistent, it is unlikely to represent actual outcomes from imperfect competition between companies with a range of different constraints and objective which reflect risk management policies and the recognition of factors beyond simple short run costs
      - My modelling adopts a heuristic rather than “optimizing” approach to modelling the offering behavior and hence scheduling of controlled releases from hydro storage.
        - This approach is broadly cost minimizing but also reflects a degree of risk aversion. It is tuned through simulation and to achieve a wide use of the storage range with a reasonable trade off between the risks and costs of spill and shortage. This approach simulates the impact of restrictive access to contingent storage by lifting the hydro offer guidelines to bring forward thermal backup generation earlier and hence reduce the weeks in contingent storage towards zero.
        - In the longer term my modelling focuses on a workably competitive market with relatively free entry and a parties achieving an adequate but not excessive commercial return.
  - **We’ve used back-casting as a way of calibrating/testing the modelling approach to actual market outcomes.**

2

THE CONTEXT OF THE STUDY – MARKET CHANGES

System development over time: the transition towards a new entry equilibrium by 2035

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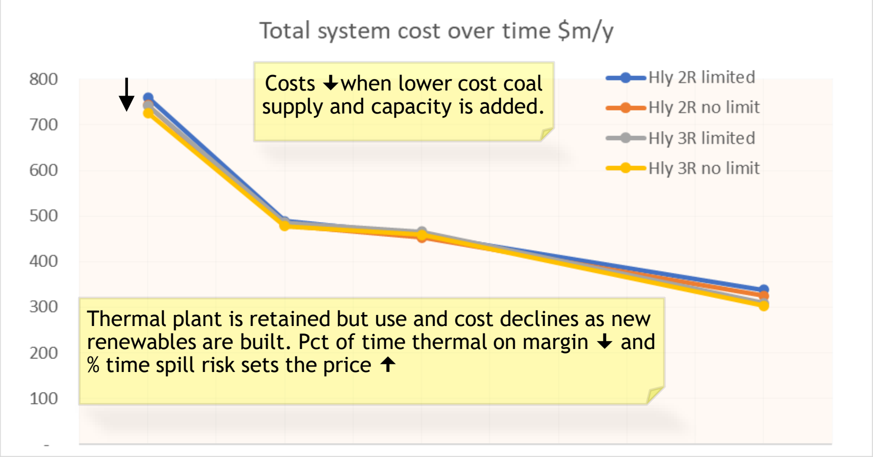
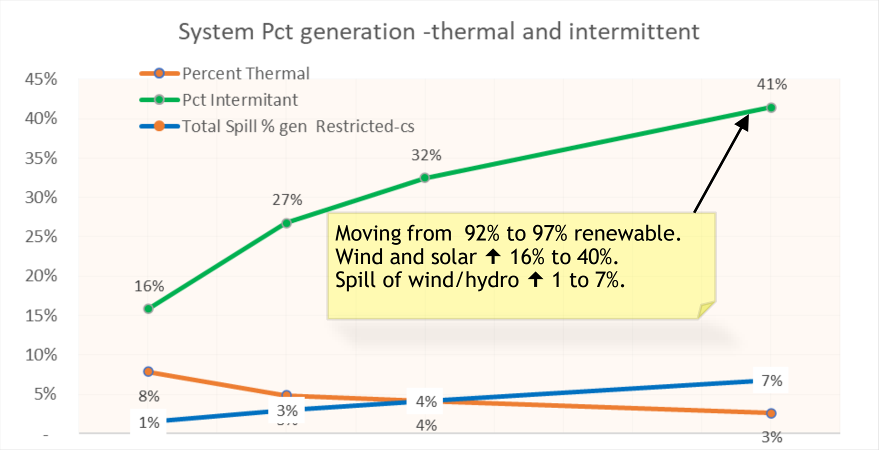
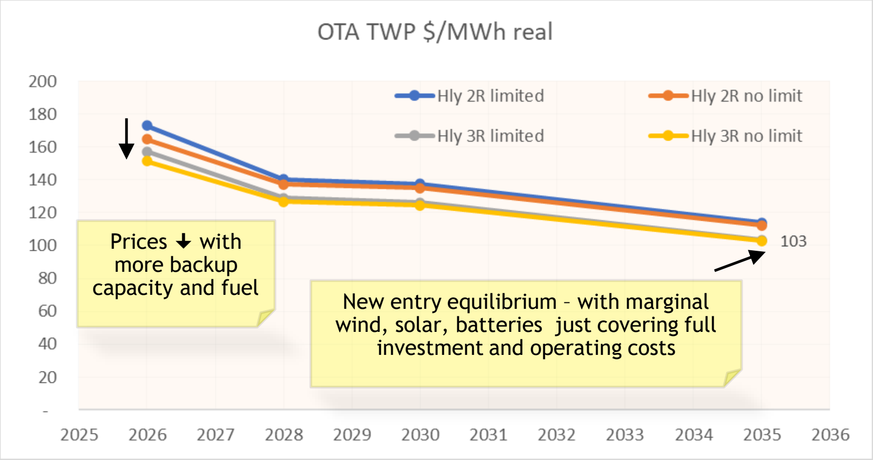
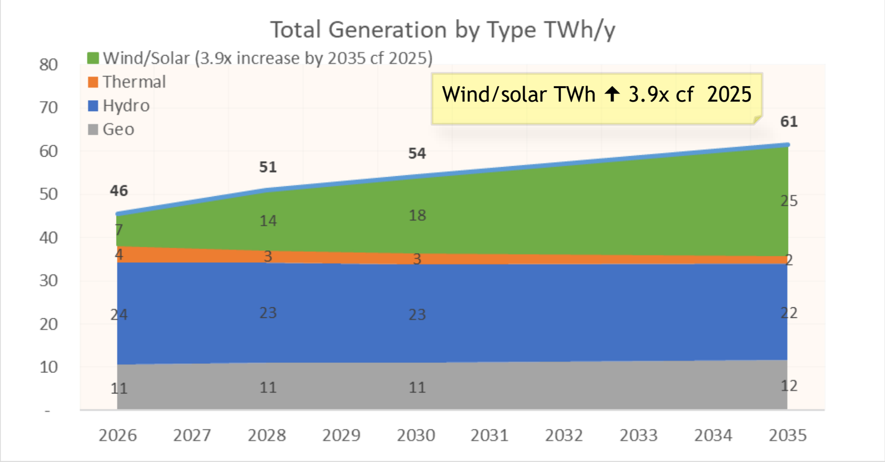
I have modelled the system as we go from the current situation with an "economic" shortage of renewable supply through to a new entry equilibrium by 2035. I have also looked at the impact of 4 scenarios with combinations of coal stock supply and capacity. As the system moves to an equilibrium the percentage of time that thermal costs are marginal declines and total spill increases









Thermal & Demand Assumptions (to 2035)

- **Baseline**
  - TCC closes; all other thermal retained to 2035
  - Demand = TP Medium (including 10 TWh/yr major loads
- **Gas Plants**
  - E3P: Full winter run; final tranche requires Methanex curtailment + higher gas prices
  - Other gas peakers: Up to 15 weeks winter capacity; beyond early tranches = Methanex curtailment + higher gas costs
- **Coal Scenarios**
  - Limited HLY-2R: 2 Rankines, 800 GWh (400 kt) cap over winter
  - Unlimited HLY: Coal stocks replenished in dry years
  - Limited HLY-3R: 3 Rankines, 1200 GWh (≈10 weeks full winter run)
- **By 2035**
  - Compared to 2025 +20 TWh/yr new wind & solar required for economic balance

We are going from an "economic" surplus to a new entry equilibrium by 2036

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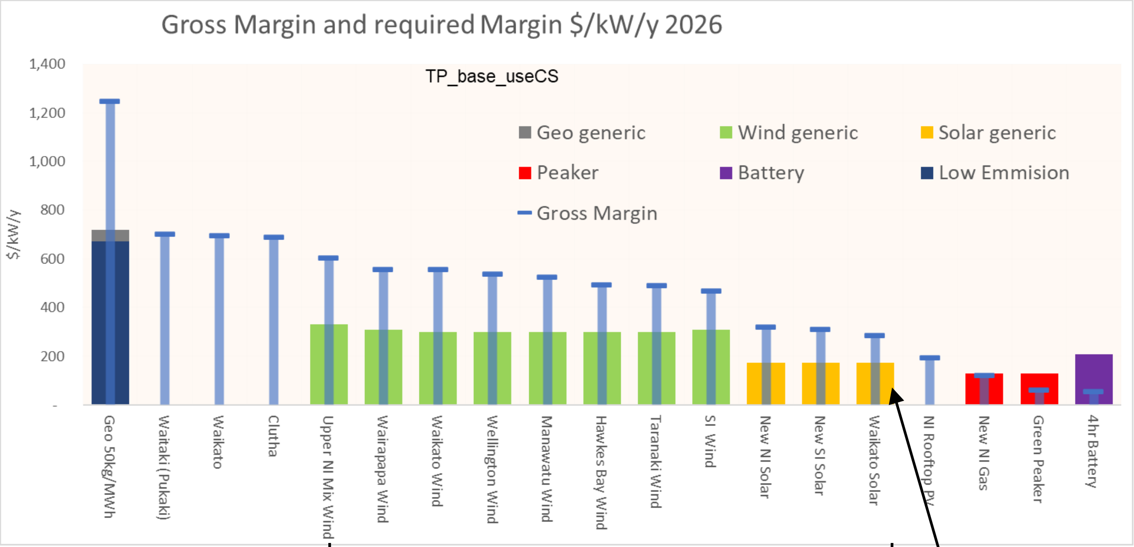
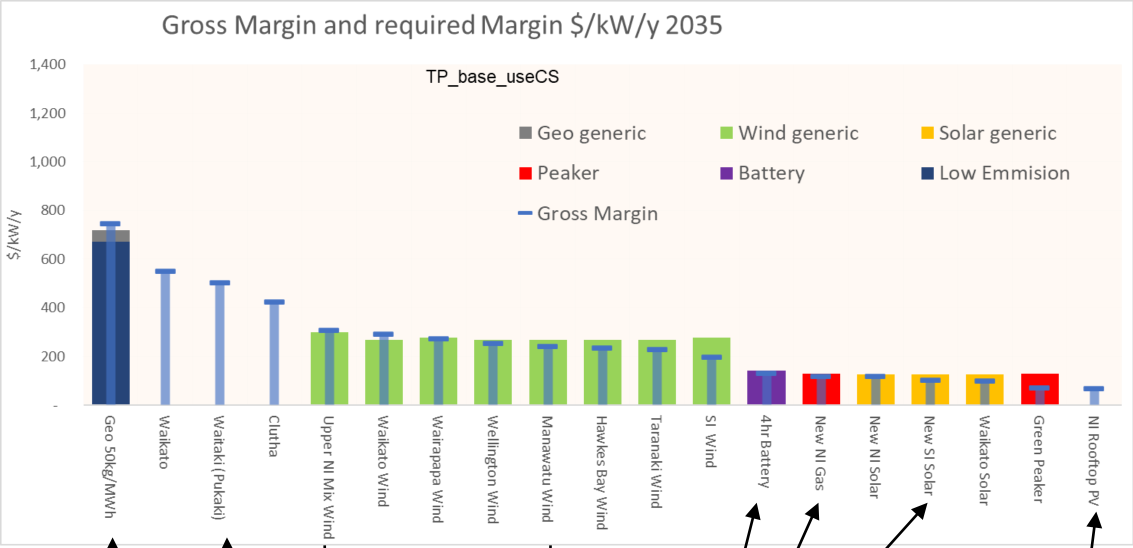
In 2026 expected average prices are above that required for new entry. New supply would normally correct for this, but this is limited by the pipeline of projects available at this time.

By 2035 a new entry equilibrium is achieved, indicated by market gross margins being close to or equal to the required operating and capital costs for marginal technologies.



Annual margin required to cover the fixed capital and operating costs for each generic technology and region is shown by the coloured bars

The gross margin earned from the spot market in 2026 is significantly above the annual revenue required to cover the cost of capital.



Geothermal supply is limited

There is no significant scope to expand existing hydro

Annual margin required to cover the fixed capital and operating costs for each generic technology is roughly equal to annual spot market gross margins for marginal plant.

Rooftop is regarded as exogenous

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KEY INSIGHTS

Explaining the trajectory chart used in the analysis

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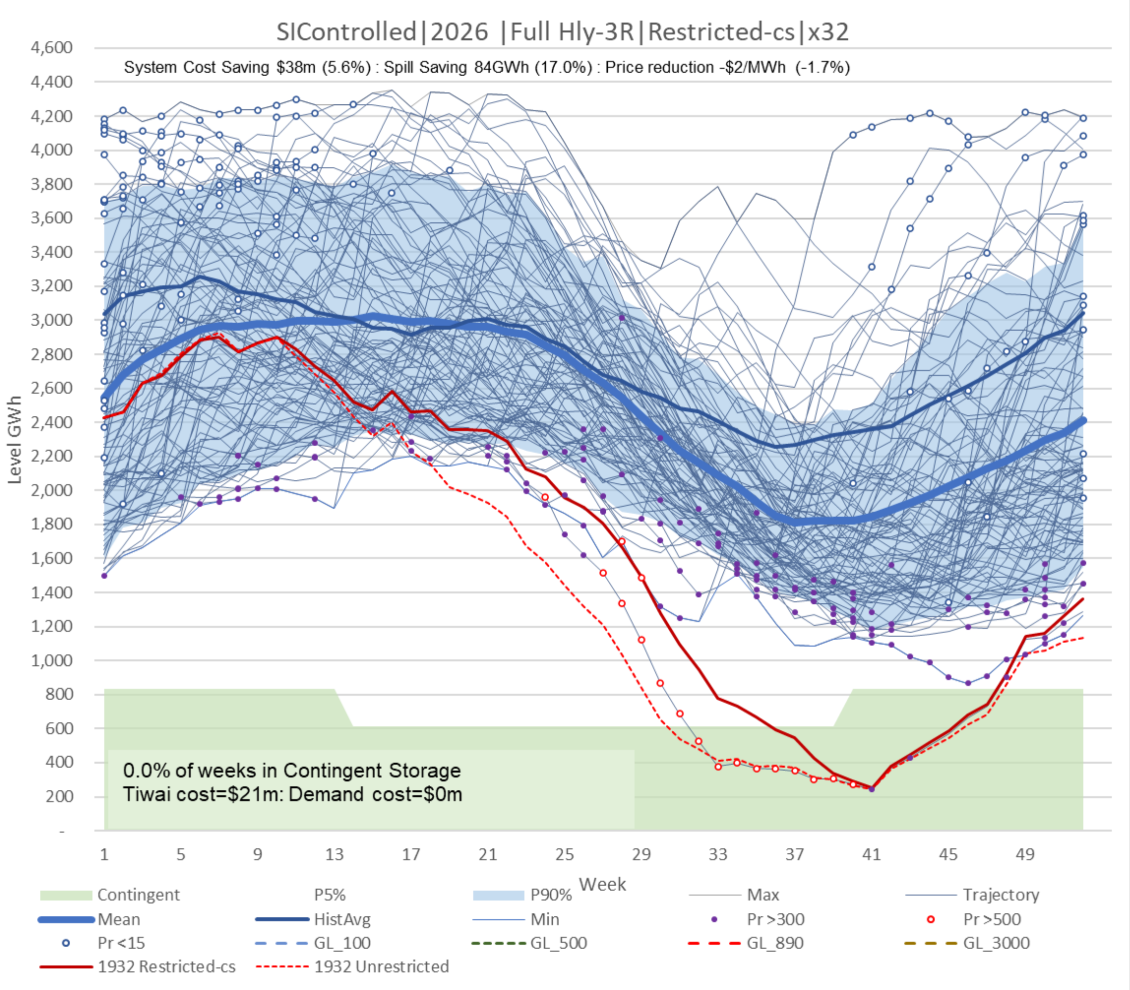
This is a sample for a 2026 year with 3 Rankine units



Storage Simulation Charts - Interpretation

- **Setup**
  - Title = storage aggregation|year|scenario|cs-Restriction Scenario
  - 93 weather years, sequential simulation (keeps multi-year correlations)
  - Averaged start/end levels ≈ equal → no adjustment for hydro value
- **Visual Elements**
  - Light blue lines = individual storage trajectories
  - Blue shaded = 5–90 percentile range
  - Thick blue line = average storage
  - Thin dark blue line = historical average
  - Green shaded = contingent storage zone
- **Price Signals**
  - Purple dots: > $300/MWh
  - Red dots: > $500/MWh
  - Blue dots: < $15/MWh
  - Dashed lines: operating guidelines (trigger thermal + demand response)
- **Stress Test Case**
  - Red line: 1932 low inflows + 28-week E3P outage – Restricted CS
  - Dotted red line: Alternative Unrestricted CS
  - Note - stress year excluded from averages
- **Notes (per simulated year)**
  - Operating cost
  - Spill
  - Average price
  - Demand reduction cost
  - Weeks in contingent zone

The impact of restricted and unrestricted use of CS is assessed by weekly simulation over 93 weather years based on demand and historical rain, wind, solar variations, and a "stress test"

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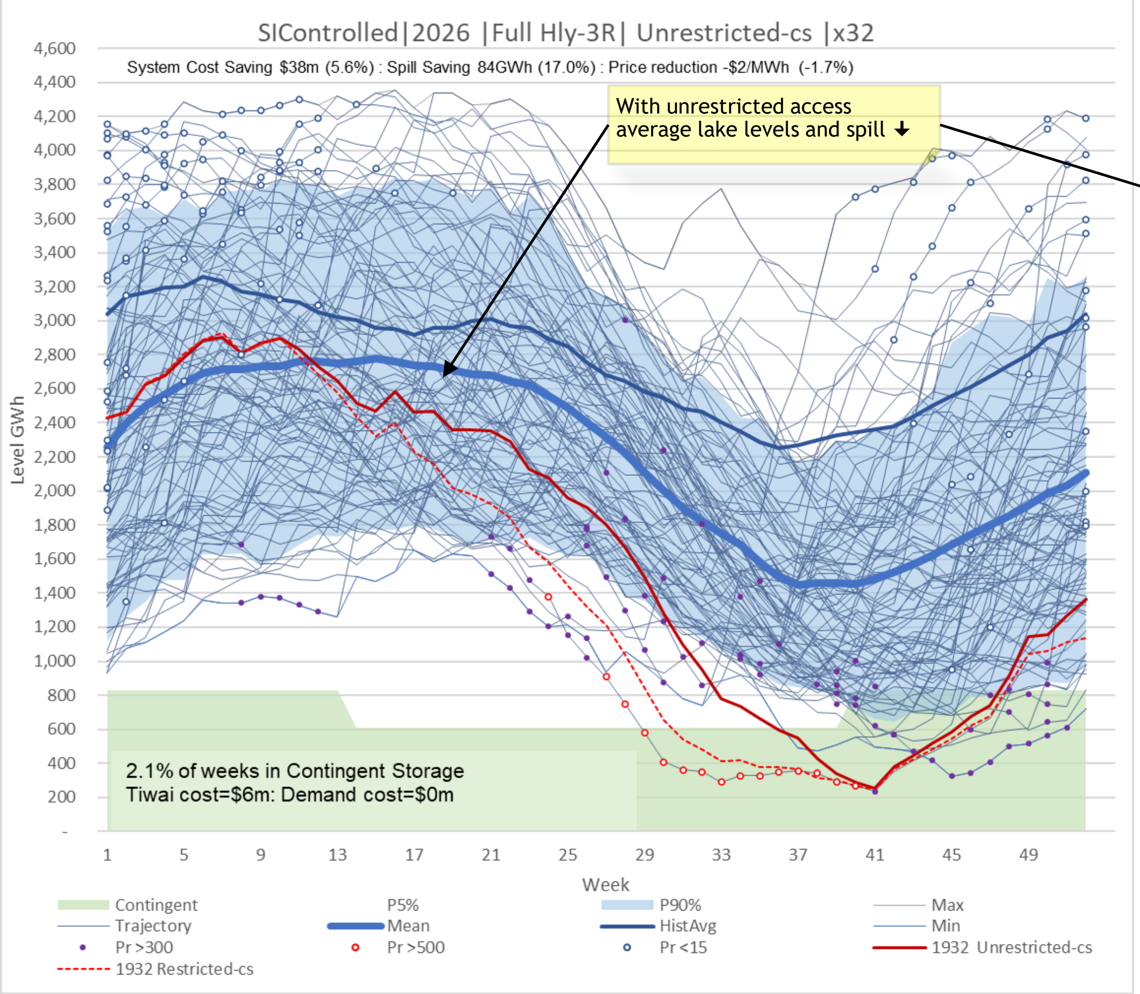
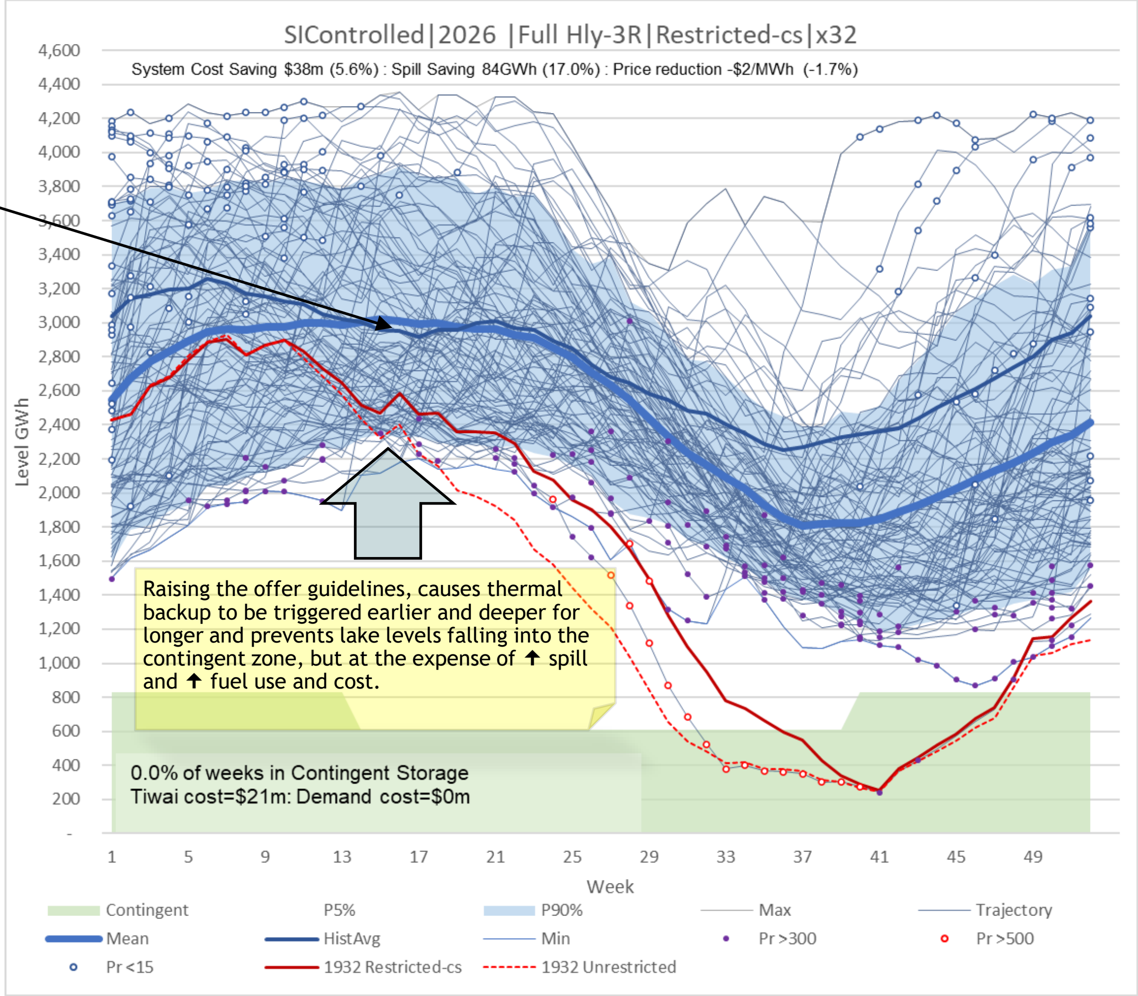
Unrestricted use of contingent storage (CS). The chart shows SI storage by week in year. Note the impact of capacity lost when CS falls below 250GWh is accounted for with a high offer of $3000/MWh.



Restricted use of CS - lakes are held higher by raising thermal offer guidelines to bring on thermal plant earlier to minimise risk/use of CS. This results in higher risk of spill and increases fuel costs.



Averaged system costs increase as use of contingent storage is restricted, primarily due to higher spill costs dominating shortage costs

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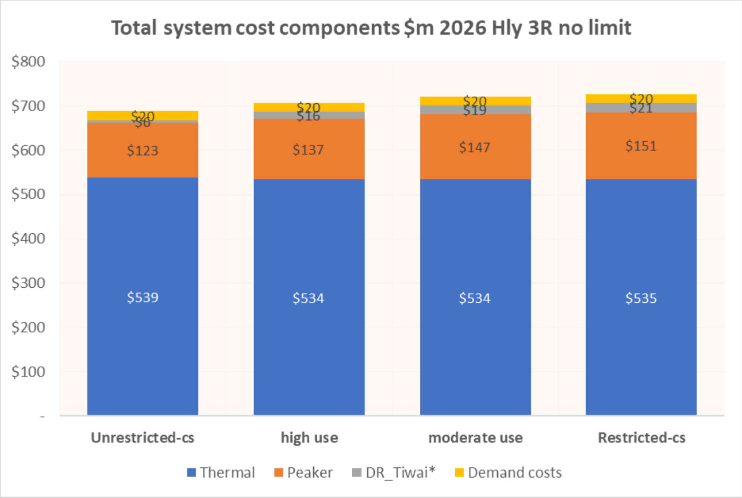
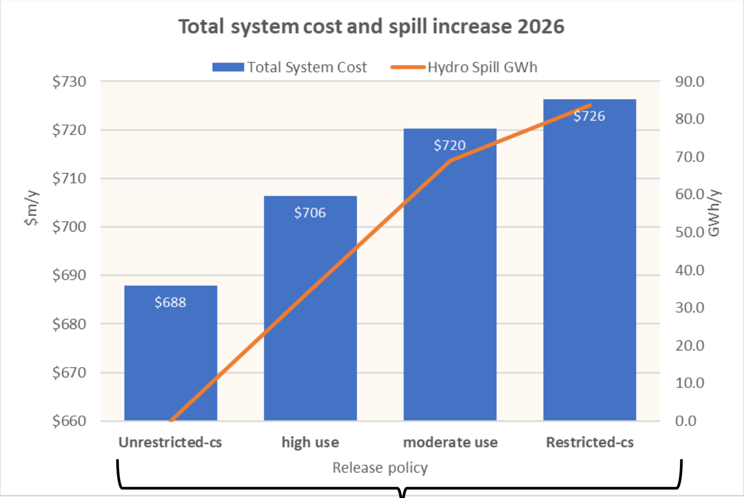
Insights

- **System Cost Impacts of Contingent Storage (CS) Restrictions**
  - Charts show shift from unrestricted use → restricted use of CS.
  - Initially assume market operators are certain they have unrestricted access to CS
  - Simulate the impact of possible restrictions on use of CS, by raising hydro offer guidelines (triggering thermal generation) until the simulated weeks in contingent storage is ≅zero.
  - This approximates the "bookend" case where market operators ignore CS almost entirely.
- **Cost Drivers**
  - unrestricted CS → savings mainly from ↓ peaker fuel + ↓ Tiwai demand
  - Minimal effect from demand response or shortage
  - Costs hinge on **fuel prices & spill**
- **Implications**
  - Costs fall steeply as % weeks in CS increases
  - Moderate restrictions (≤0.5% weeks in CS) = <½ cost of extreme "bookend"
- **Economic Logic**
  - Trigger thermal backup when shortage risk > spill/fuel cost
  - Secure system maintained as shortage costs dominate at lower thresholds
  - Raising thresholds → less CS, but more spill & higher peaker use

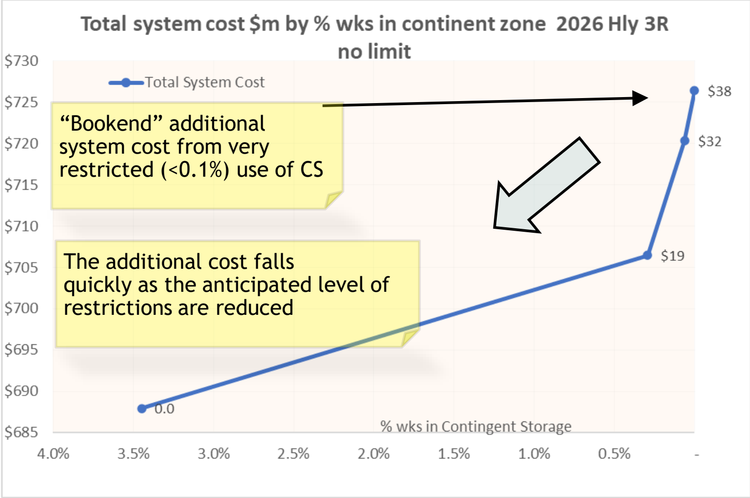
Components of system cost as function of restrictions

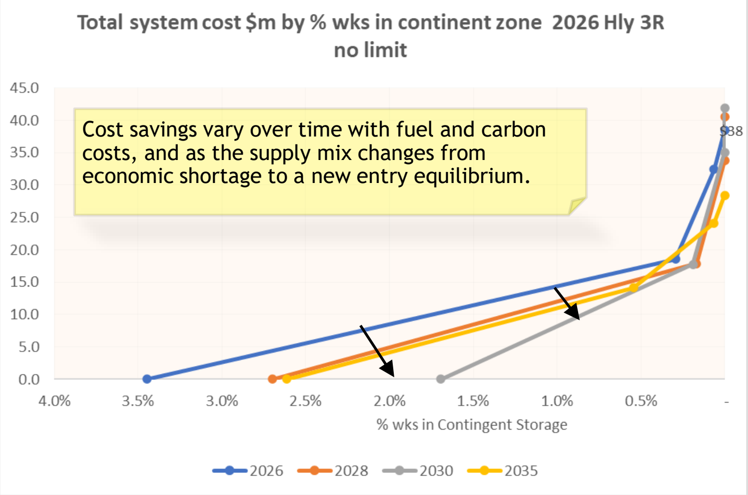




Unrestricted-cs → Restricted-cs

System cost versus use of contingent storage





Unrestricted-cs → Restricted-cs

Note : I have modelled the conservatism by raising the critical thermal guidelines to be higher earlier in the year - this is a proxy for the actual policy.

1932 worst case stress case - 2026 versus 2035 with 3rd Rankine

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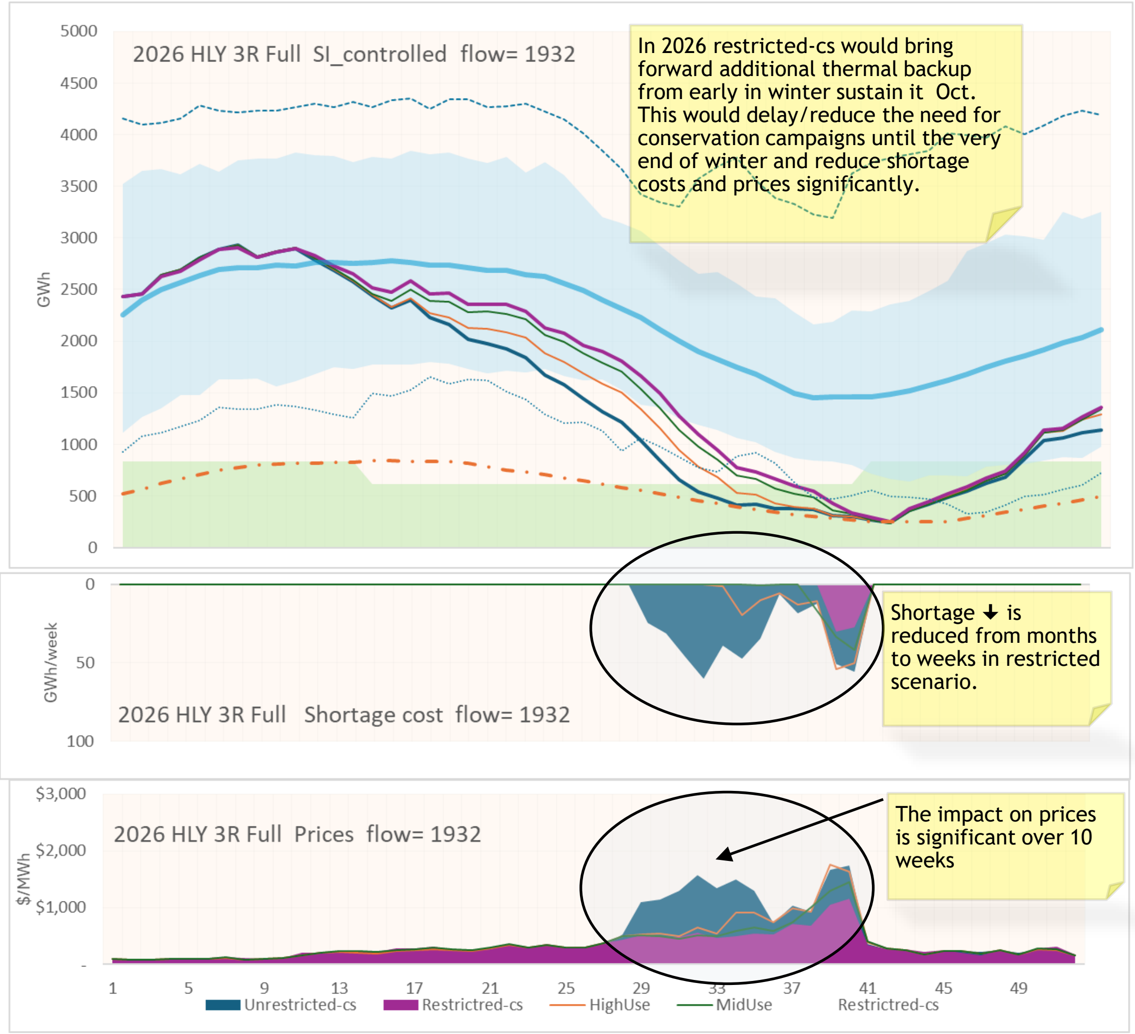
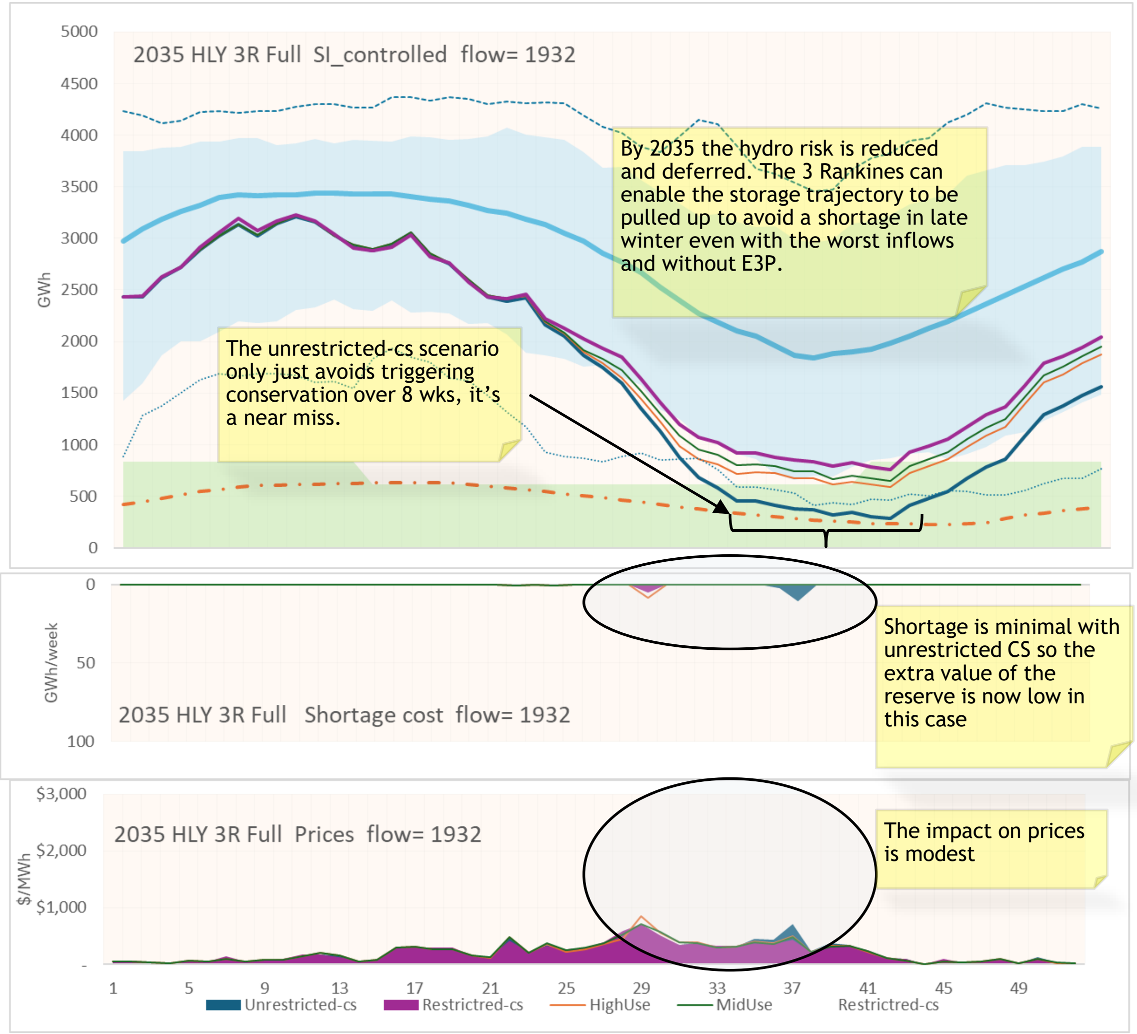
2026 with 3rd Rankine - Shortage costs are reduced. The value of the extra reserve provided by conservative CS policy is significant, but not as high as in the 2 Rankine case..



In 2035 the 3rd Rankine enables "shortage" to be avoided even with unconstrained use of CS. The calculated value of the reserve is low since there is nothing to saved. In reality the risks of "shortage" will be reduced, but are not measurable within the margin of error..



The value of the extra reserve provided by a restrictive CS policy falls off substantially we go to an economic equilibrium in 2035, provided that 2 or 3 Rankines are retained ..

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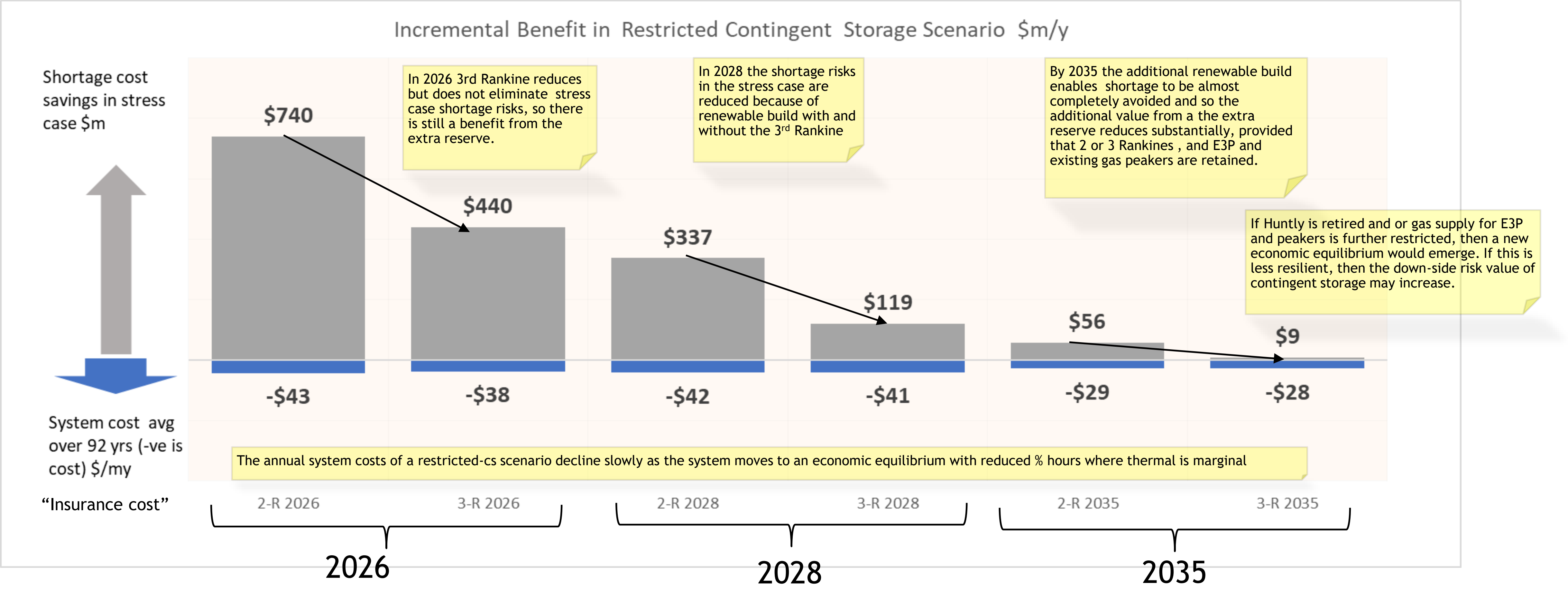
In 2026 the system is in economic disequilibrium. There is a substantial benefit from a conservative policy in reducing tail risk shortage costs with 2 Rankines. Adding another Rankine reduces the tail-risk benefits, and reduces the cost of CS policy conservatism slightly. Risk aversion will determine if the benefits in stress cases offsets the ongoing annual "insurance" cost of higher spill and system cost.

By 2035 the system reaches equilibrium and so the costs of conservatism are reduced to around $30m per year. The value from reducing tail-risk shortages is significantly reduced, as the system can handle these provided that new renewable investment occurs and existing coal and gas backup plant is retained.



A restrictive-cs scenario may increase price volatility modestly but there are offsetting impacts so averaged prices might fall slightly or increase depending on offer behaviour

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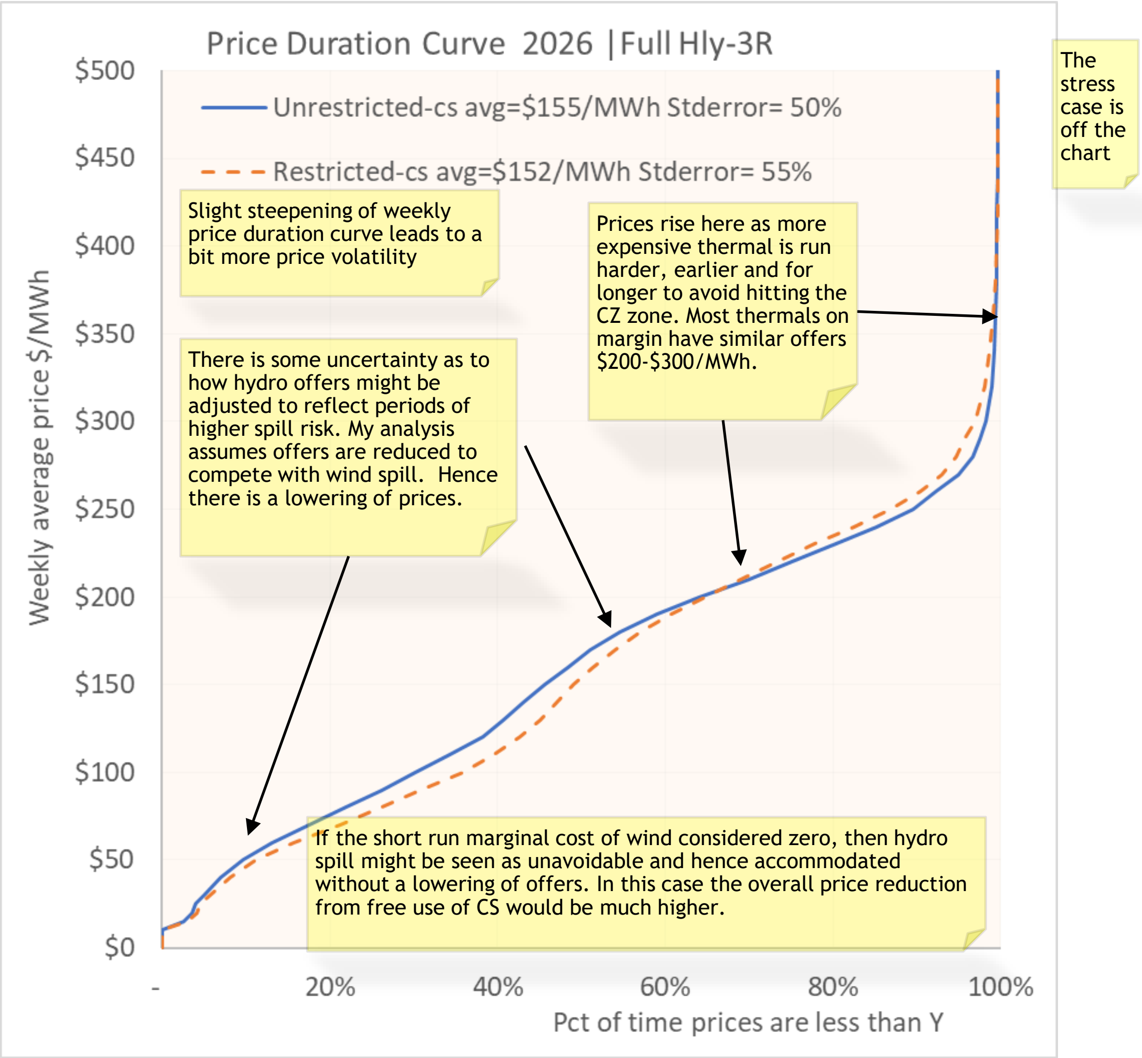
Insights regarding average price levels

- Spot Price Impacts
  - **Price levels depend on hydro offer behaviour**
  - **Modelling assumes offers are interpolated between thermal guideline levels**
  - **A restricted-cs scenario results in higher thermal guidelines**
- There are Offsetting Effects of Higher Guidelines
  - **↑ Earlier/longer peaker use → more high-price periods**
  - **↓ Higher storage → lower prices when lakes are fuller and spill risk increases**
  - **↓ Larger CS reserve → much lower prices in a stress case with double contingency**
- Net Impact - depends on balance between ↑ and ↓
  - **Because of offer behaviour uncertainty I have calculated high and low estimates**
    - Lower: includes the negative and positive averaged over all 92yr as modelled
    - Upper bound: ignores all the negative impacts
  - **In 2026 - with 3 Rankines in the Restricted-cs scenario - excluding stress case**
    - The low and upper bound estimates are -$3/MWh to +$7/MWh increase relative to Unrestricted-cs.
    - The impact of the stress case in 2026 could be -$140/MWh (whole year). Depending on risk aversion, this adds **-$1 to -3/MWh** to the average.
    - Taking all into account, expected impact could be - or + within a small range
  - **By 2030-35 the system is in equilibrium and the expected price impact of restricted-cs is expected to fall to between -$1 and +1/MWh**
- Price Volatility
  - **Weekly volatility rises modestly (50% → 55% in 2026)**
- Perspective
  - **Price effects are mainly value transfers, not net system costs relevant for national cost benefit analysis.**

The chart shows all the simulated weekly average prices over all the 92 weather yrs excluding the stress case.



Allowing unrestricted use of CS saves system costs, but reduces margins which risks loss of stored fuel or Huntly capacity (3rd Rankine)

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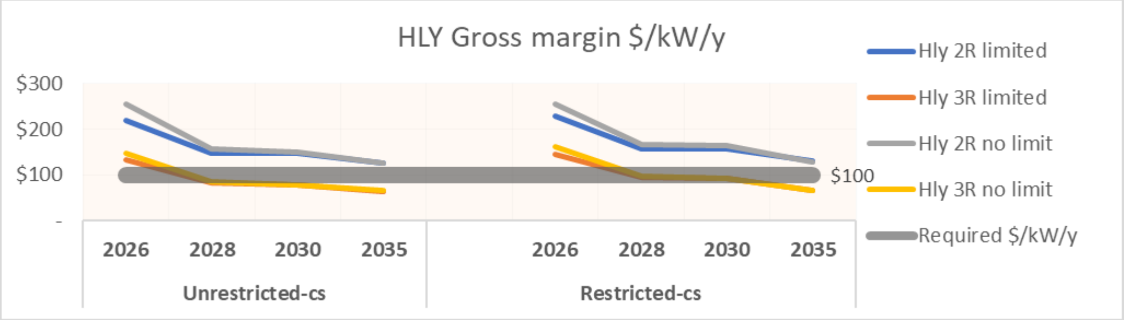
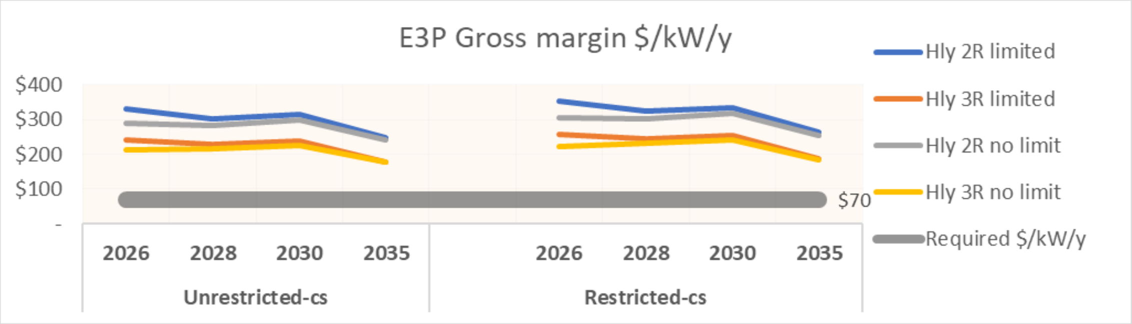
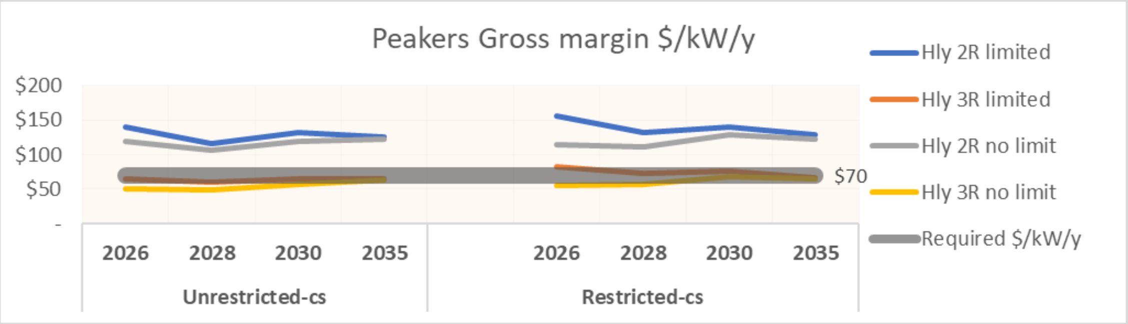
Unrestricted use of CS will reduce gross margins for thermals by around $5 to 20/kW/yr. This may possibly lead to lower stocking levels at the peakers and maybe Huntly.

- **Thermal Plant Gross Margins & Viability**
- **General Effect**
  - Unrestricted CS → lower thermal margins
  - Restricted CS → higher margins (+$5-20/kW/yr)
- **Key Question**
  - **Margins must cover:**
    - Fixed O&M
    - Fuel/stockpile holding
    - Sustaining capex
- **E3P**
  - Margins appear sufficient to stay in service under simulated prices
- **Huntly**
  - **Needs ≈ > $100/kW/yr margin:**
  - $20-40/kW/yr fuel holding
  - $80/kW/yr fixed O&M (Concept 2023)
  - Uncertain viability for 3rd Rankine → withdrawal or smaller stockpile could cut costs
- **Gas Peakers**
  - Fixed O&M ≈ $20/kW/yr + $50/kW/yr gas holding = $70/kW/yr needed
  - Margins fall short in 3-R case with free CS
  - Could avoid gas holding costs via tighter gas supply energy limits
- **System Trade-off**
  - Unrestricted CS saves system costs but risks loss of stored fuel or Huntly capacity

Estimated Gross margins in 2026 to 2035







Note: For this I assume E3P can access around 30% at $10/GJ and the remaining at $20-$17/GJ - other costs are met from gross margin. Huntly pays an average $8.6/GJ for base coal - storage and other operating costs need to be met from gross margin. Gas peakers pay an average $20-$17/GJ and other storage and variable costs are met from the gross margin.

3

ASSUMPTIONS

Assumptions 1

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Base case assumptions - slide 1

- This summarises the base case results for selected target years : 2026, 2028, 2030 and 2035.
  - All prices are NZ constant real dollars in 2024 terms, unless otherwise specified.

- Demand follows Transpower's medium case
  - This including "additional" demand for datacentres and other large loads - reaching 10TWh/yr by 2035
  - The medium case includes an additional 1.8TWh of load in 2026, I assume that this will not be fully realised in the next 6 months - and so I allow for a delay.
- For the base case it is assumed that TCC is retired in 2026, 2 or 3 Huntly Rankine units and E3P run to 2035, existing gas and oil peakers continue to 2035.
- New investment is based on the range of potential investment identified by Transpower for the SOSA.
  - It is assumed that Contact will maintain existing capacity by build new geothermal to replace the aging Wairakei plant as it is retired. An additional 100-200MW is assume to be available by 2035.
  - Solar projects are based on a delayed phase-in from the identified pipeline.
  - Wind projects are developed as quickly as possible given the pipeline
    - Offshore wind is not economic in the time frame ..
  - For 2030 and 2035 it is assumed that wind/solar developments are increased (within the limits of the identified pipeline) to achieve a new entry equilibrium accounting for the significant additional new "step" demands, by 2035.
- Prices:
  - The base gas price (excluding carbon) is assumed to be $17/GJ, with a $5/GJ adder for gas peakers to reflect the cost of low capacity peaker operation, storage and transport.
  - The base coal price is $8.6/GJ, with an additional $2.4/GJ cost for additional transport, handling and coal stockpiling holding costs.
  - New entry capital costs are based on the TPM assumptions.

Assumptions 2

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Base case assumptions - slide 2

- Fuel constraints are based on Transpower SOSA assumptions:
- The Huntly Rankine units can potentially run on either coal or gas. I model coal use, as gas for other thermal plant is limited.
  - A continuous stocking policy which aims for pre-winter target stockpile of around 10 weeks running (800GWh for 2 Rankine, and 1200GWh for 3 Rankine) and also allows for addition coal shipments as the stockpile empties during evolving dry years as required.
  - A separate sensitivity explores the impact of fuel being limited to the winter target.
- For modelling I assume that there is sufficient gas available to meet the combined winter demand from E3P (up to 24 weeks full running) and the gas peakers (up to 15 weeks full running), if necessary based on gas diverted from Methanex.
  - This assumption is based on Enerlytica's medium gas forecast and relies on Methanex remains in NZ (with a normal demand of around 70TJ/d), and can be reduced to 50TJ/y year at a high cost of > $20-25/GJ and be completely shut down for several months in extreme dry years, if necessary, at a cost > $25-30/GJ.

4

2024 CALIBRATION – BACK-CASTING

Back casting / Calibration Results

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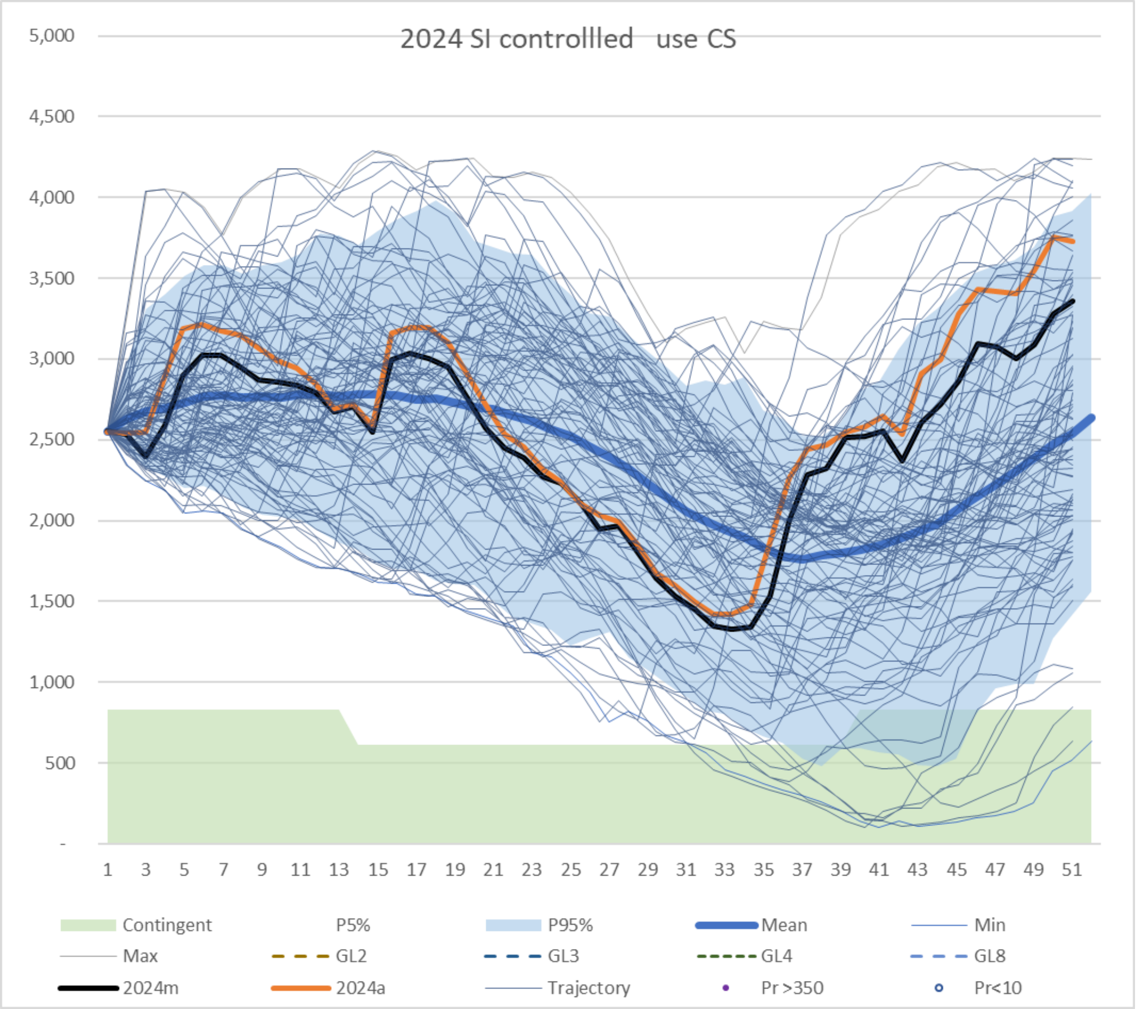
I have carried out a bask-casting exercise to check the performance of the model.

- **2024 Simulation vs Actuals**
- **Setup Adjustments**
  - Initial storage aligned to 1 Jan 2024 actuals
  - Geothermal: new units + Aug/Sept outage included
  - TCC: adjusted availability, withdrawn after Sept 2024
  - Huntly: 2 Rankines assumed fully available (did not include impact of 3rd Rankine for some weeks)
  - Cogeneration: standard average profile (actuals varied)
  - Demand: adjusted to observed 2024 pattern (incl. Tiwai recovery & DR)
  - Gas: assumed flat $25/GJ (actual: ↑ early, ↓ after Aug)
  - Manapouri: allowed storage > 450 GWh due to high inflows
- **Results**
  - Lake levels: good match overall; some mis-allocation by site; late-2024 mismatch from Manapouri inflows & rule approximation; winter minimums well captured
  - Prices: broad level in line; profile mismatch due to flat gas price assumption
  - Generation mix: matches well (esp. non-discretionary geothermal, wind, solar); differences from outages, random demand, hydro rules & thermal offers
- **Takeaway**
  - Simulation captures storage & average price levels reasonably well
  - Profile mismatches highlight sensitivity to gas price path & hydro rules

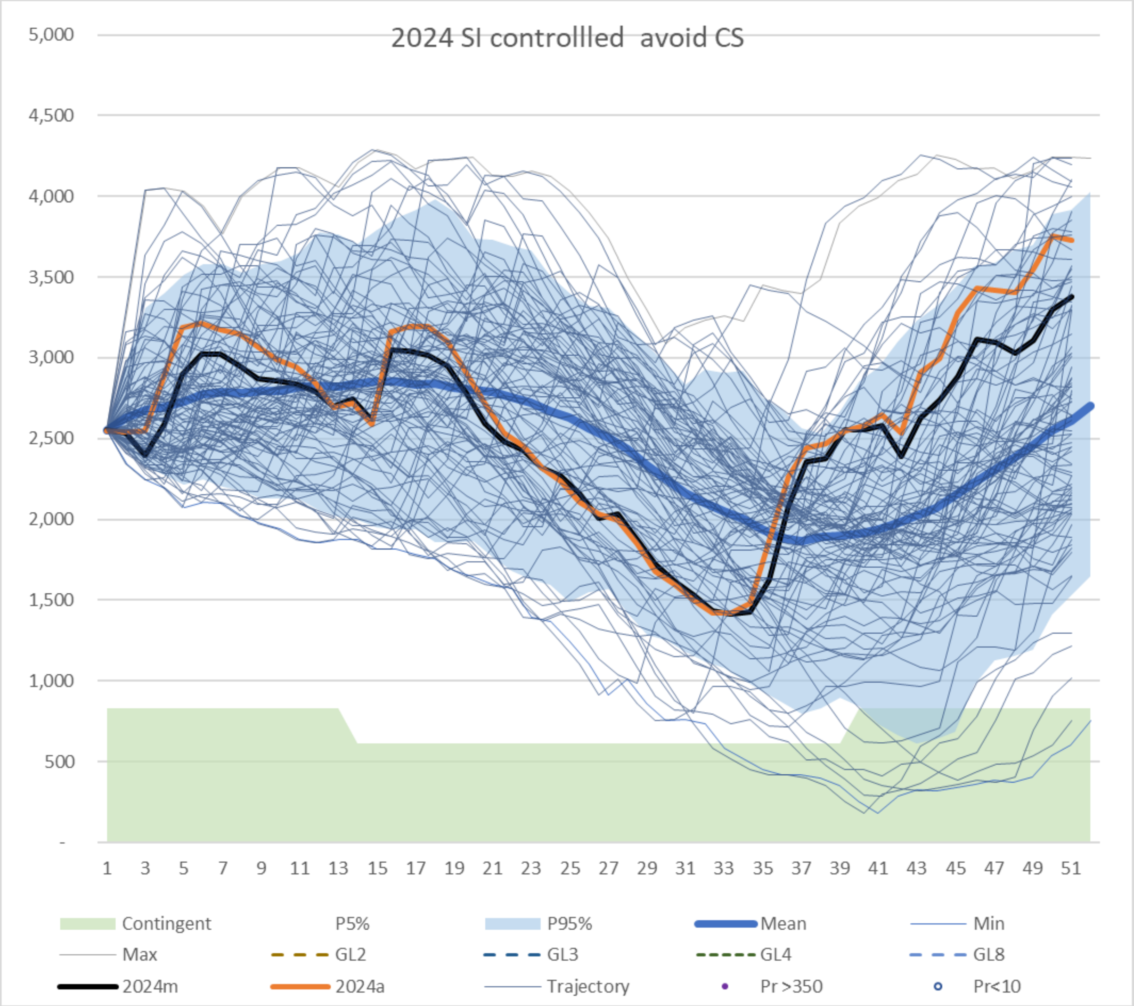
Simulated and Actual SI total controlled hydro levels in 2024

JC2

The modelled SI controlled storage trajectory in 2024 follows the actual reasonably well. The simulated minimum is close. There is a growing divergence towards the end of the year which reflects issues around the approximate approach applied to Manapouri's management during high inflows ..



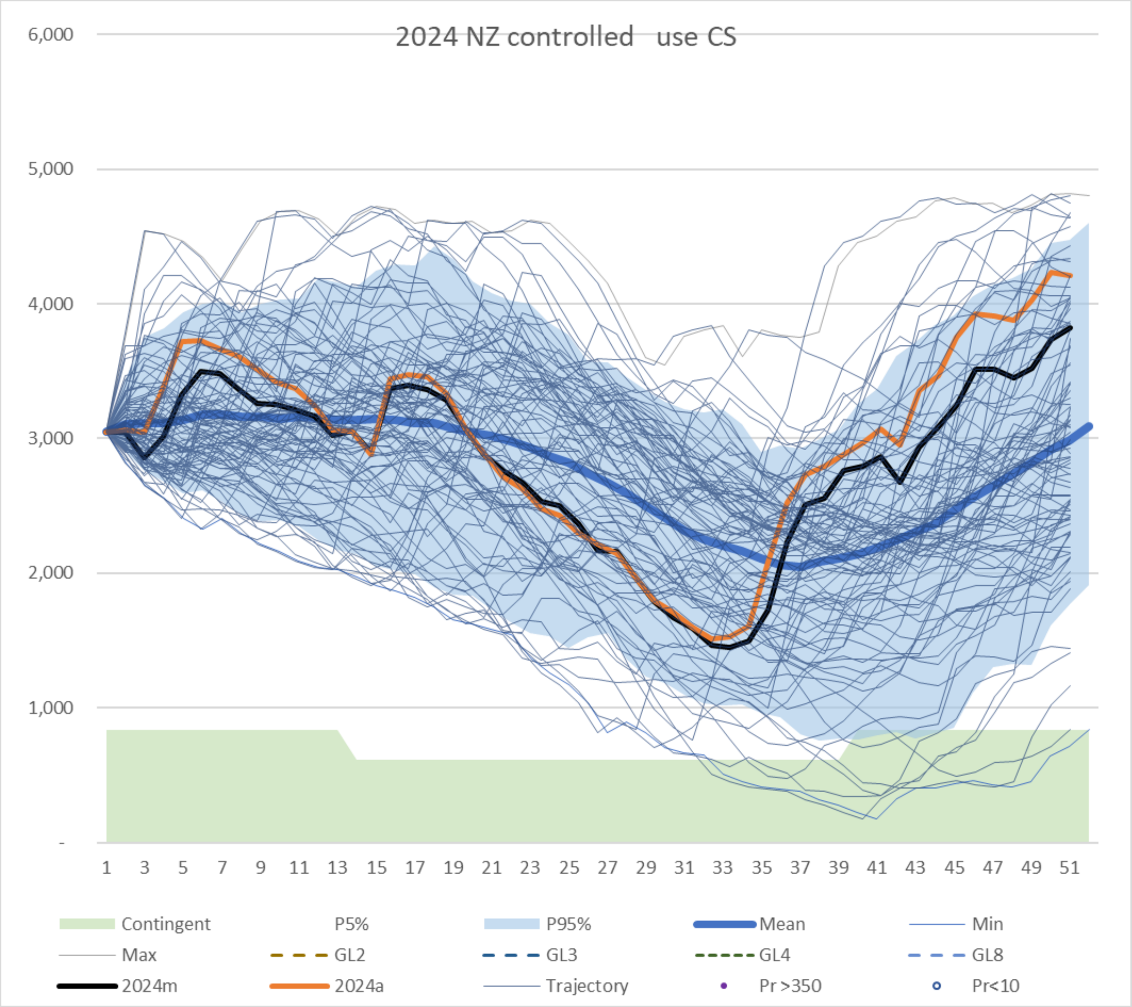
The simulation with operating guidelines that avoided Contingent storage also match reasonably well .. but the



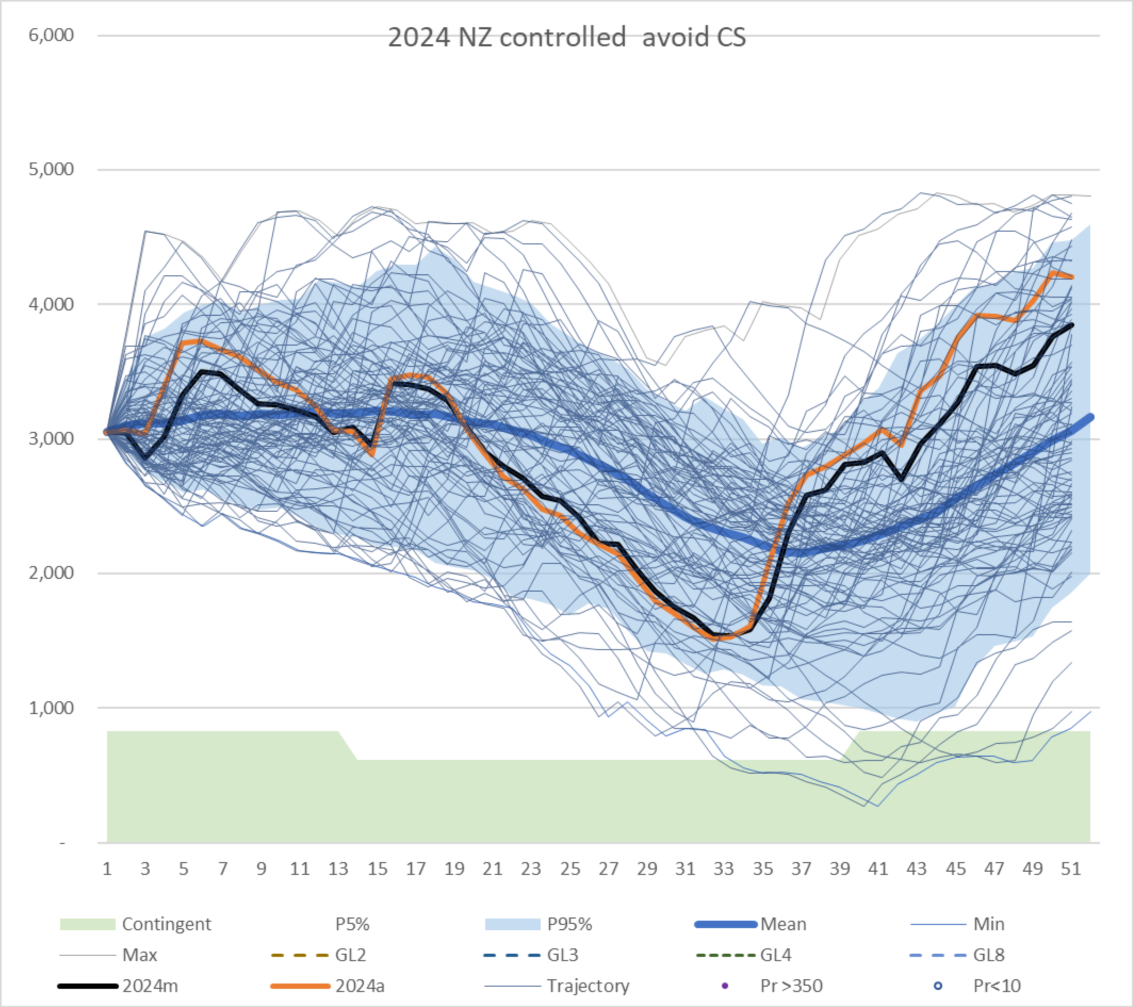
NZ Storage tracks well also ..

JC²

With free use of Contingent Storage

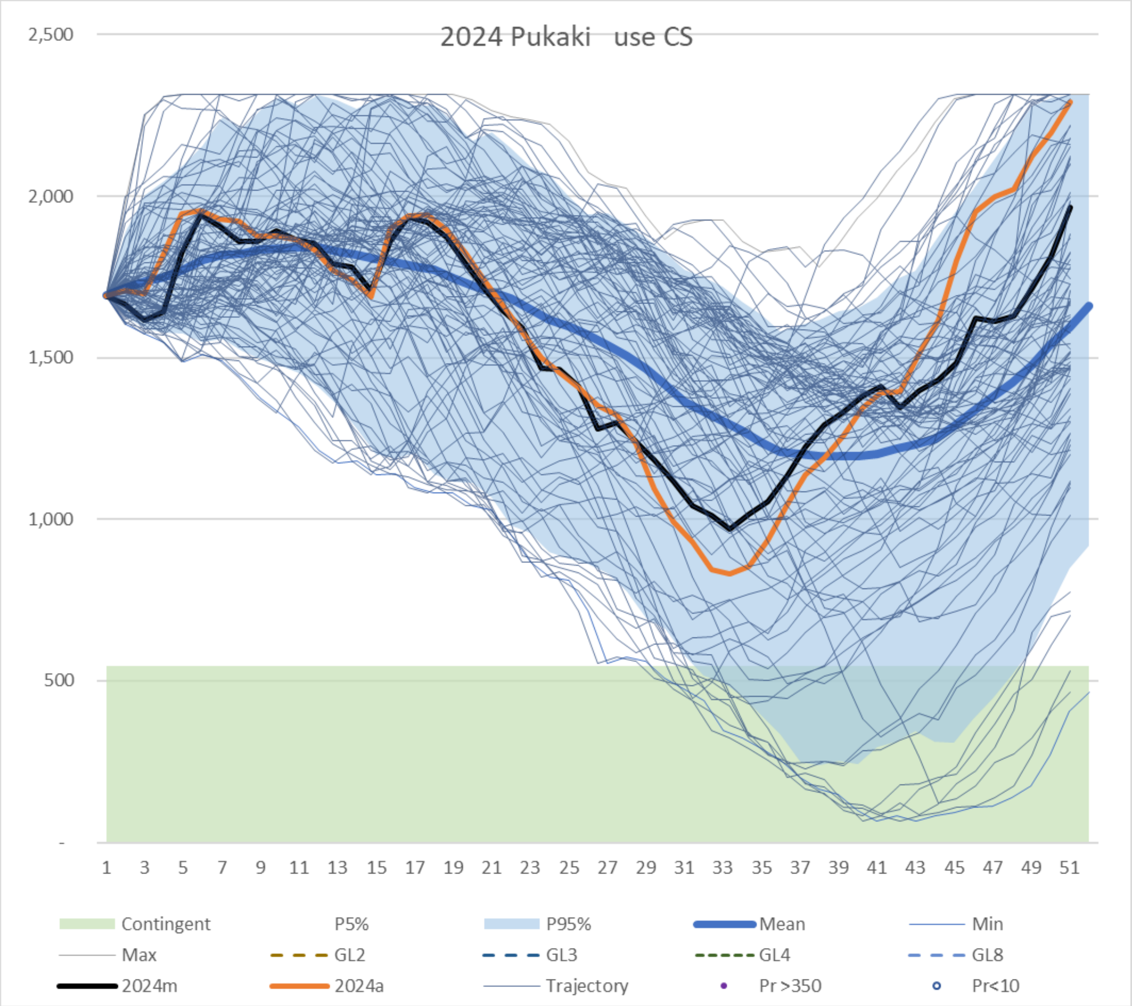


With restricted use of Contingent storage

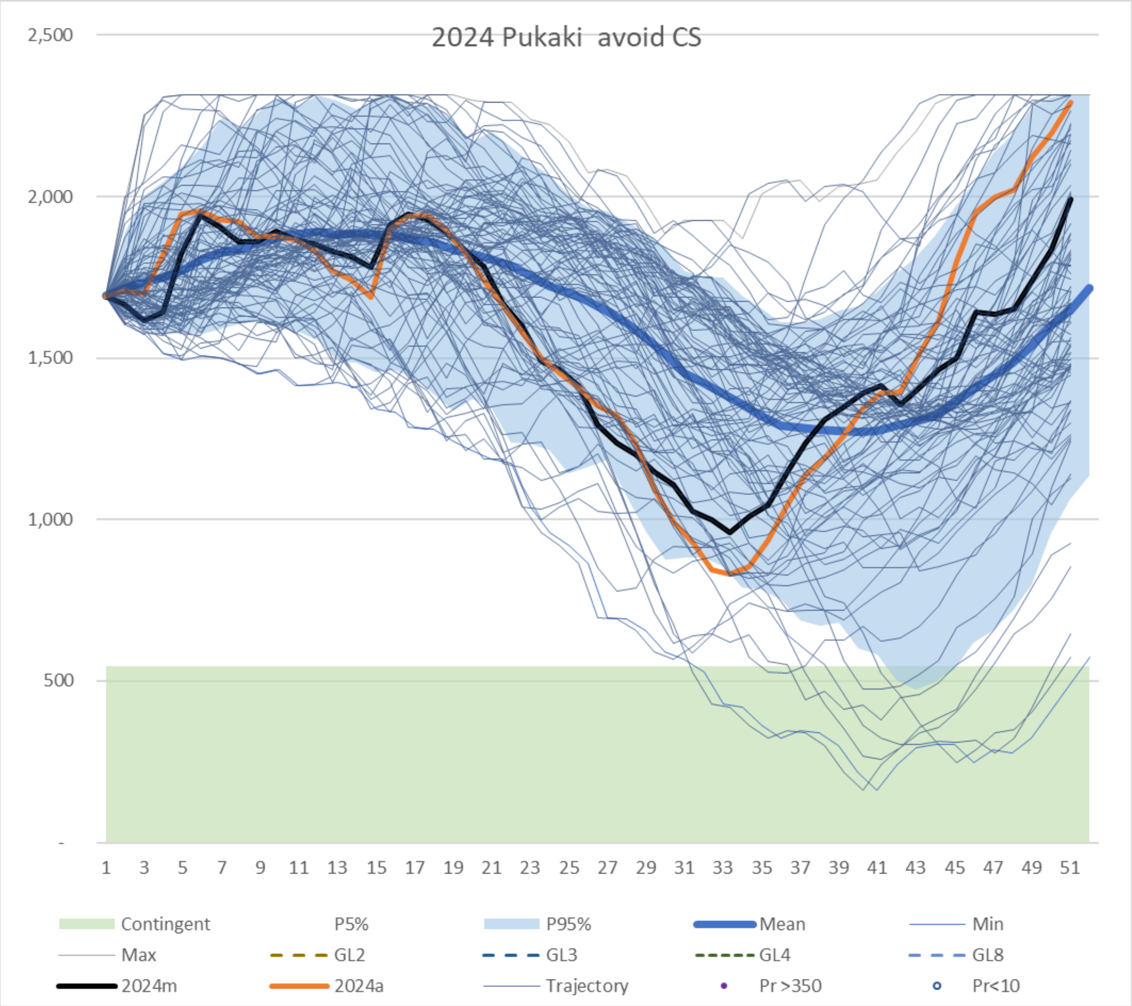


Lake Pukaki tracks well also ..

With free use of Contingent Storage



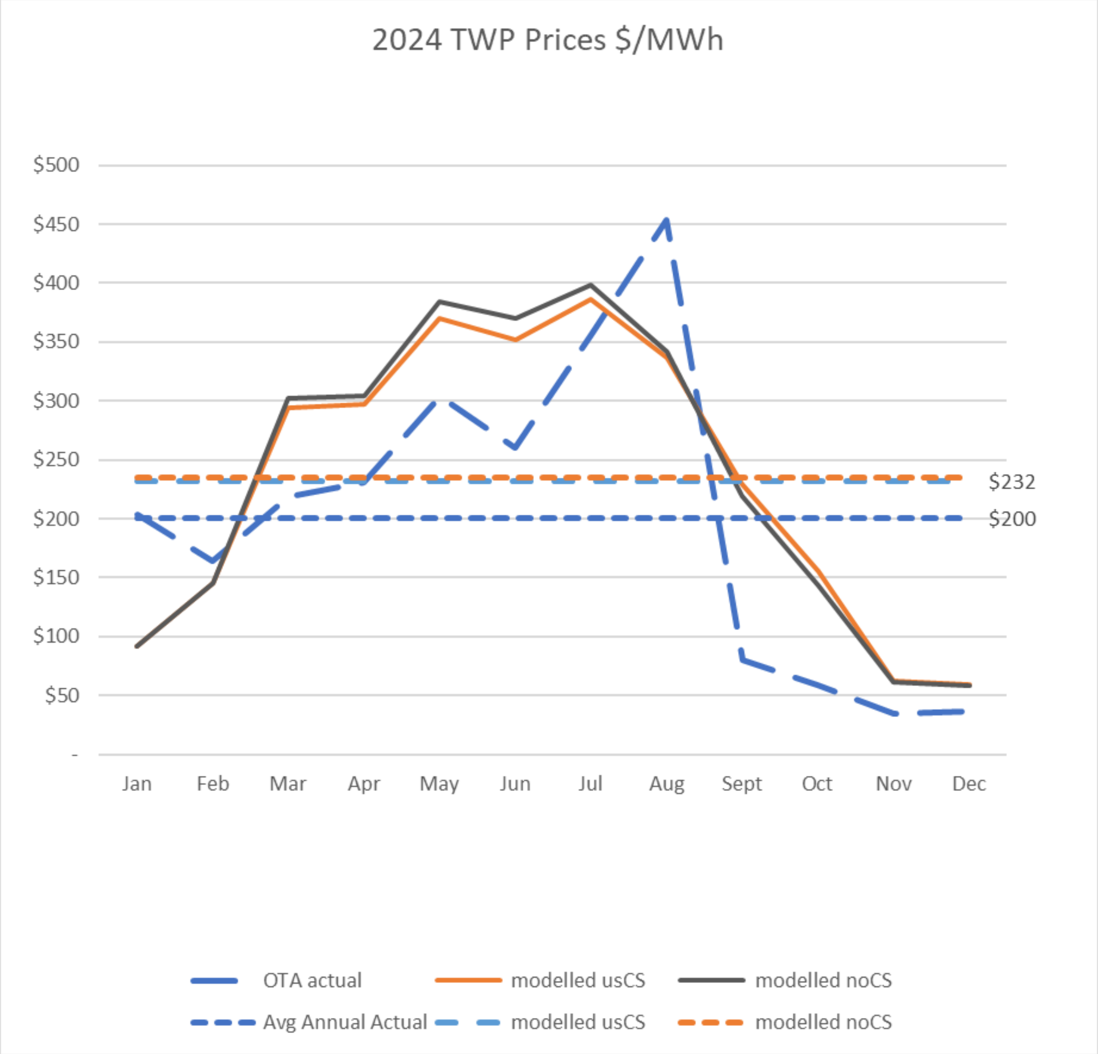
With restricted use of Contingent storage



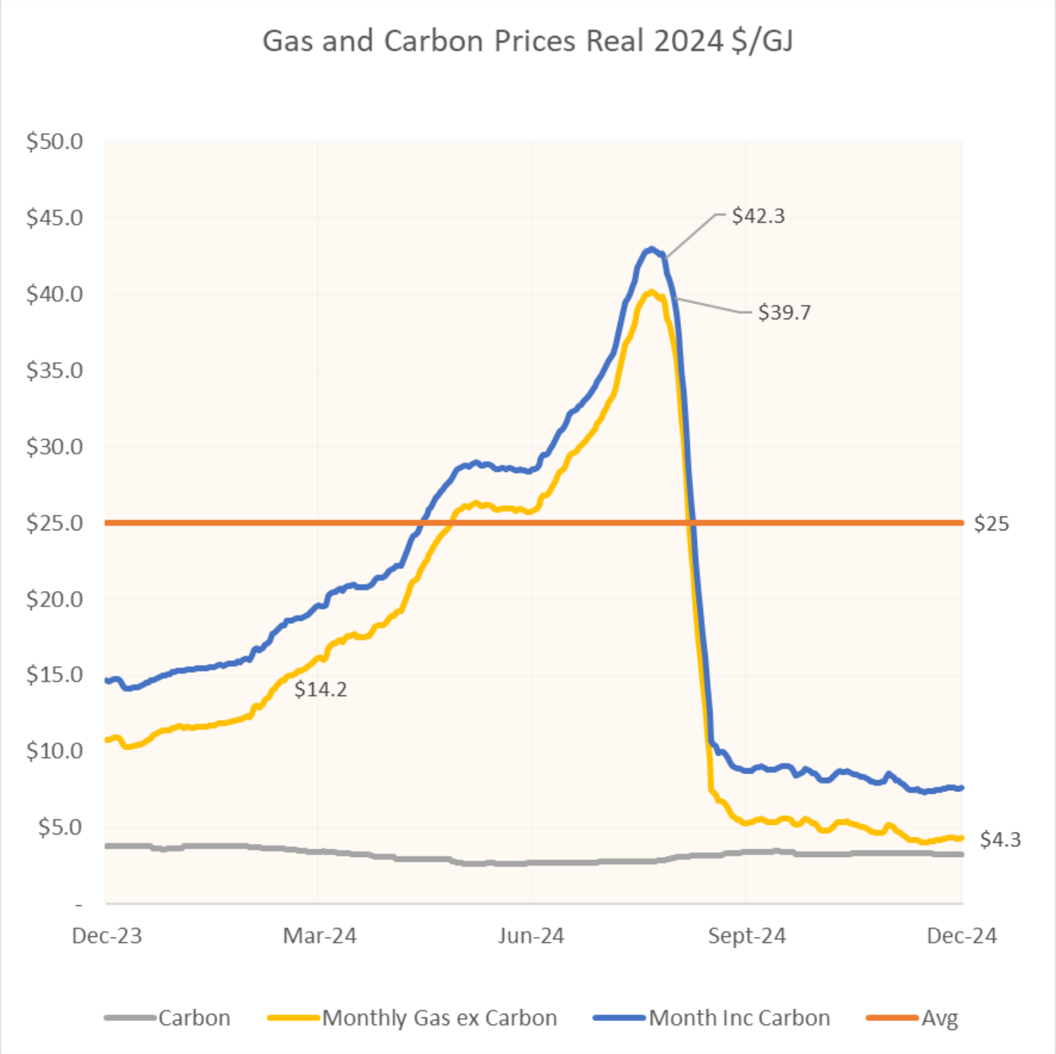
Market prices – approximate the observed level, but the gas price profile is not modelled ..

JC2

Simulated time weighted average prices versus actual – if gas price profiles were reflected in the modelling the match would be much better



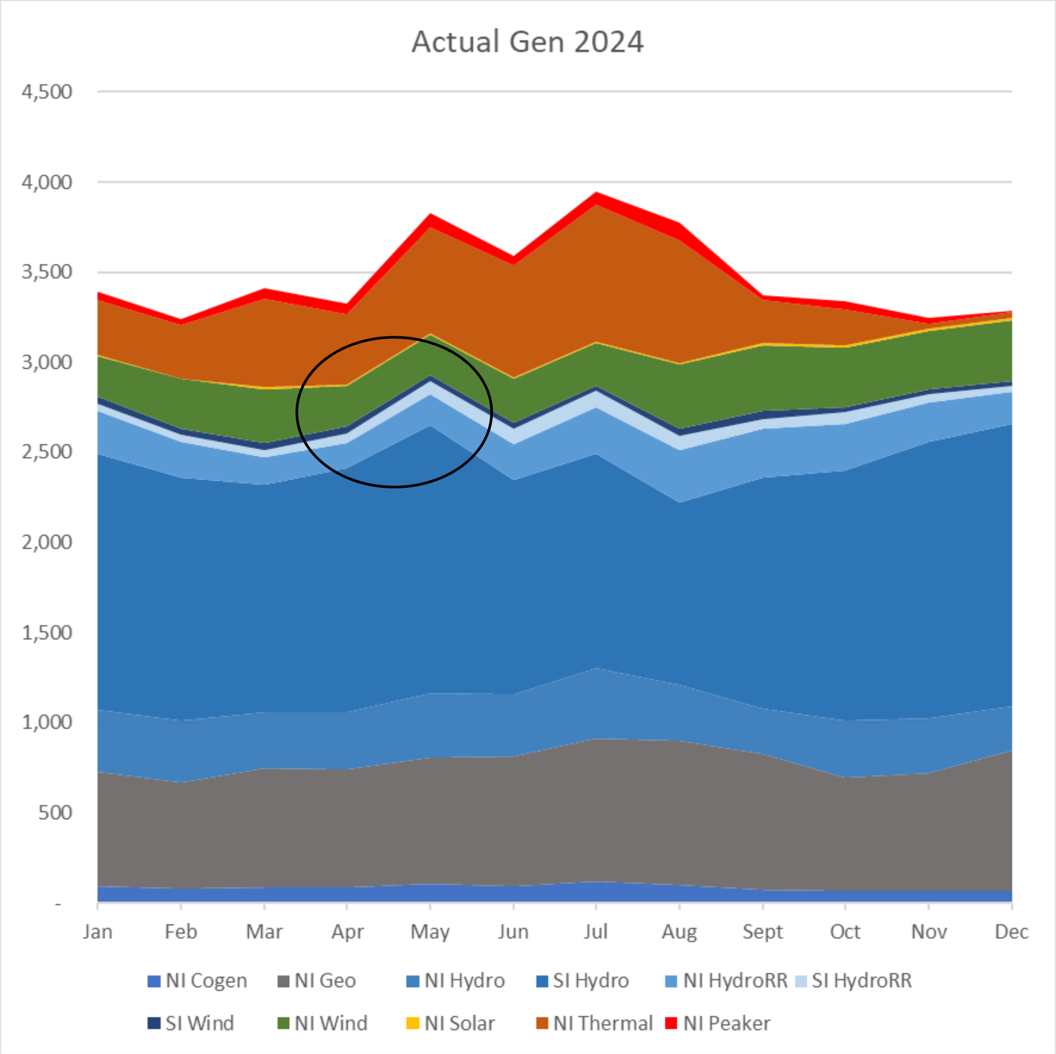
Actual and assumed gas prices over 2024



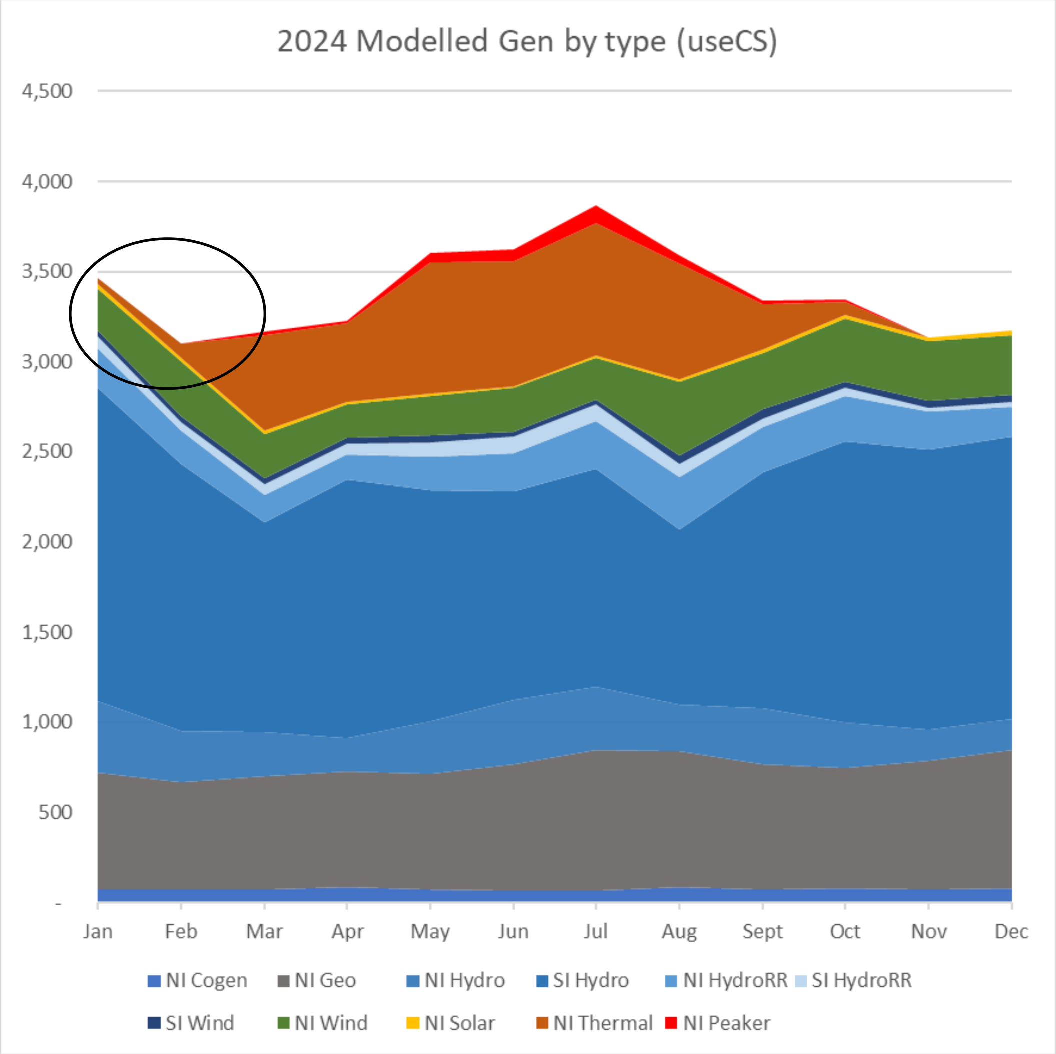
The modelled breakdown of generation by type reflects actual reasonably well, but there are monthly variations ..

JC2

Actual generation in 2024



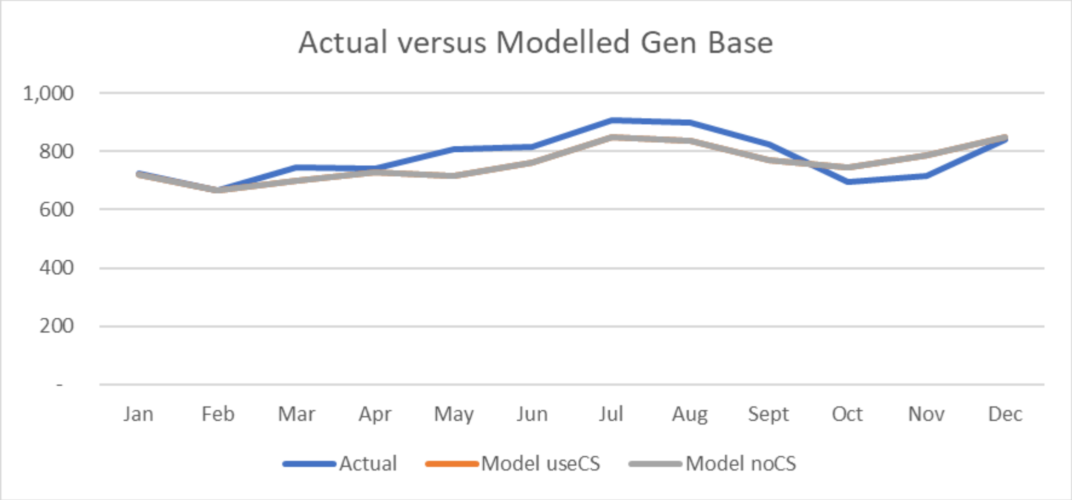
Modelled generation in the 2024 weather year - assuming Contingent storage is used ....

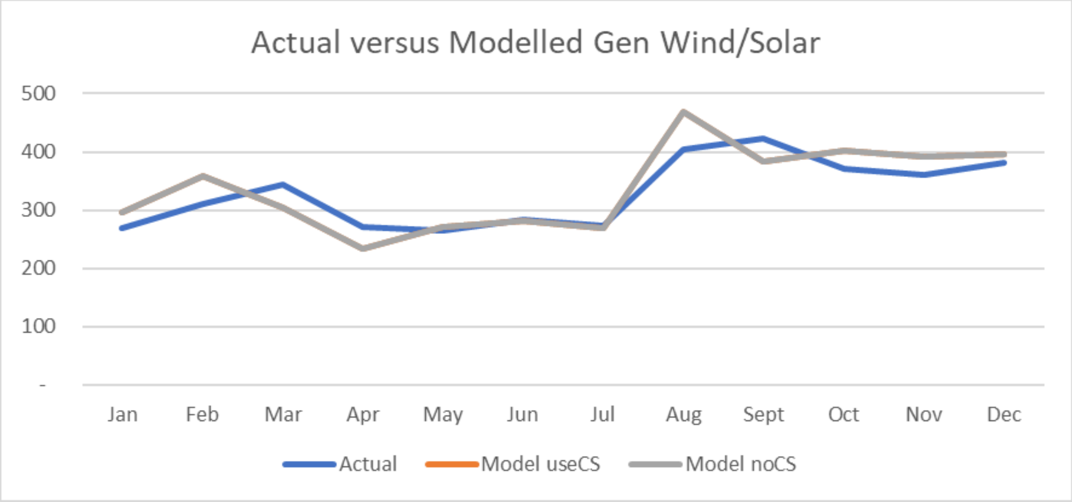


Modelled generation matches actual pretty well on a monthly basis

JC2

Geothermal and Cogeneration and wind/Solar





Hydro and Thermal - match pretty well - except for Jan