Price Discovery with 100% Renewable Electricity Supply
Final

Prepared for Market Development Advisory Group

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ASSUMPTIONS

See appendix for more detail

Demand – Key Assumptions in the Reference Case

- We model demand in 2035 and 2050 representing 2 levels of decarbonisation.
- Demand follows the the Climate Change Commission's demonstration path.
  - This is broken down into underlying, new process heat and electric vehicle demand
- The seasonal pattern of underlying load and low temperature process heat follows historical patterns
  - New food processing heat follows a summer oriented dairy pattern
  - EV load has a slightly summer oriented profile
- There is extensive allowance for short term demand management in the <u>reference case</u>.
  1. Smart EV charging for 70% of average EV MW load is available – this allows load to be shifted up to 5 hrs within a day
  2. A portion of batteries associated with rooftop PV is assumed to be available for wholesale market backup
  3. Demand response is available in various tranches priced from $700 to $1500/MWh
- The <u>enhanced demand management scenario</u> increases both flexible load and load shifting:
  - This increases smart EV charging load shifting by an extra 30%
  - Adds 400-600 MW (in 2035 and 2050) additional fully flexible demand triggered at prices ranging from $30 to $300/MWh.
    - This is assumed to respond to price only and can be sustained over hours or weeks as required.
  - It is assumed that the extra 400-600 MW of flexible load substitutes for a similar level of underlying demand so the total demand for generation remains the same as the reference case.

The reference case has a high level of load shifting. The enhanced demand-side response scenario adds 400 MW of flexible load and around 30% more 5-6 hr load shifting

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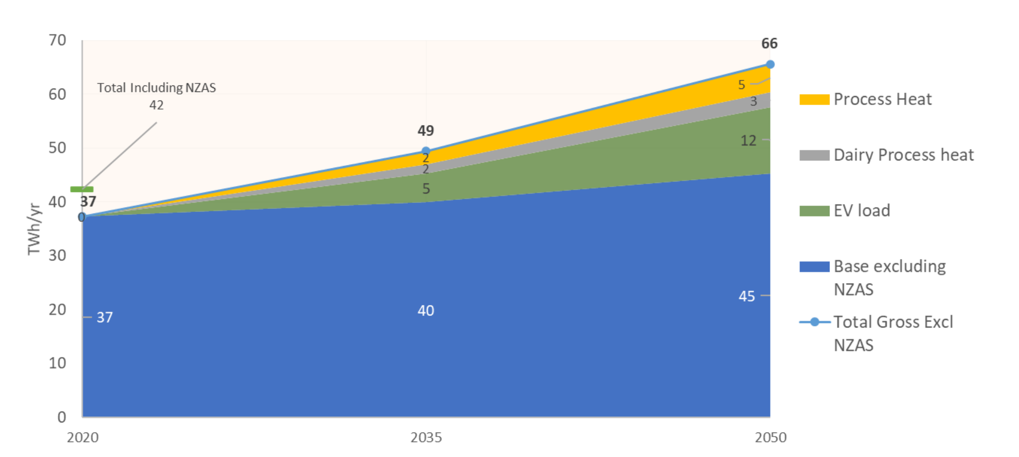
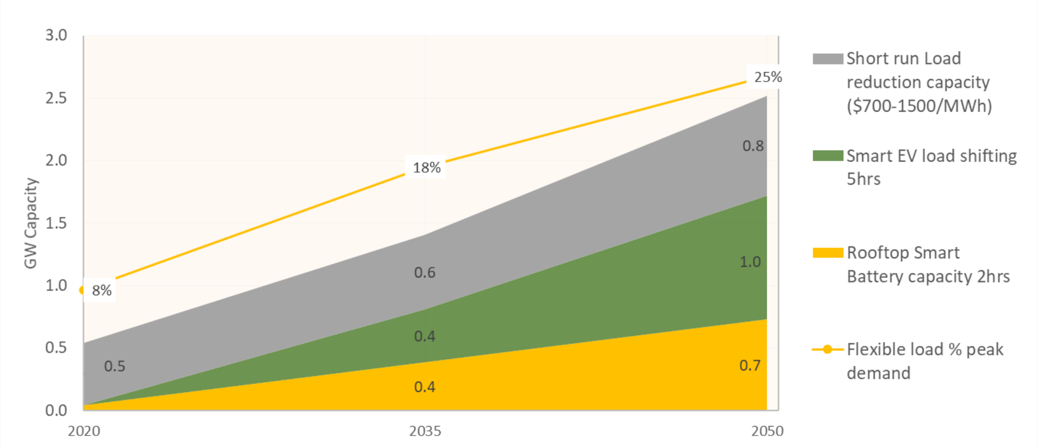
Reference case demand and load shifting and flexible demand

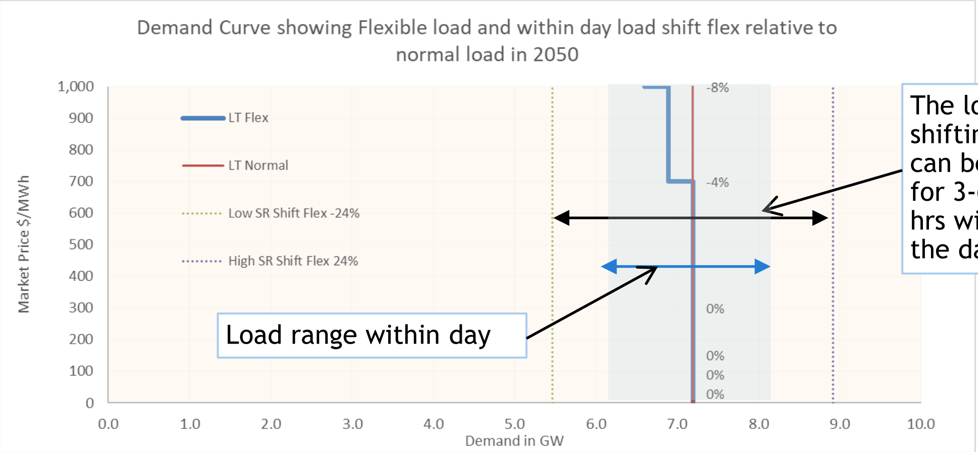
EVs and process heat drive the increase in gross electricity demand. Underlying electricity demand growth is largely offset by efficiency gains.





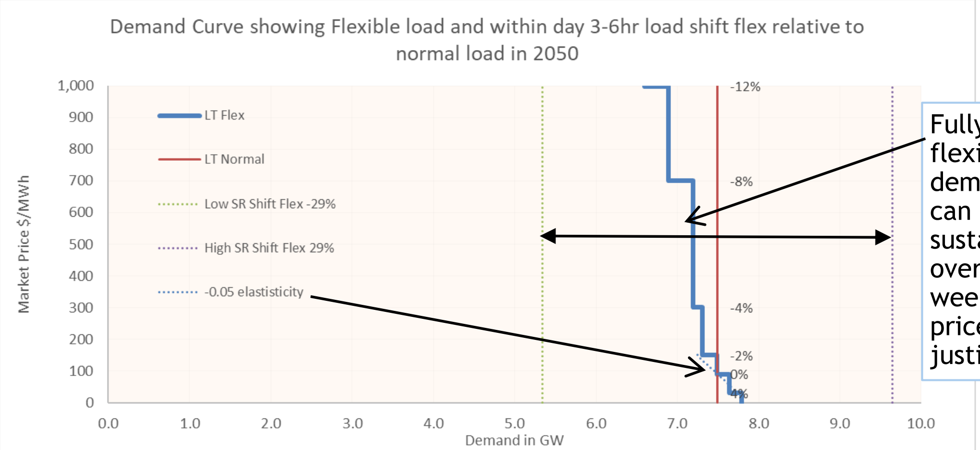
Note the very significant increase in price responsive flexible demand from 8% to almost 25% of peak demand by 2050.

Reference case demand response includes tranches of high price demand response and substantial within day load shifting capacity from distributed batteries, and smart EV charging.



The load shifting can be for 3-6 hrs within the day.

Reference case levels of demand load shifting and flexibility



Fully flexible demand can be sustained over the week if prices justify

Higher levels of demand load shifting and flexibility

Assume an extra 400 MW of fully flexible load triggered at lower prices and 30% higher 4-6 hr load shifting capacity in the enhanced demand-side scenario. This could result from EV-> grid and/or additional thermal heating/cooling load shifting.

MODELLING APPROACH

Key question and how we address it

Core question

- We are seeking to understand how spot price volatility will change in a 100% renewable system
- We could also explore how price volatility may change in the transition – but that is excluded for now

We model the system in three time periods

- '2020' – to represent the 'current' system. We use a benchmark simulation calibrated to average historical prices and compare modelled results with observed actual volatility over the last 20 years
- 2035 – an early year in 100% renewable world. This year should be sufficiently far into the future to avoid transition issues (such as thermal retirements) but soon enough to give a sense of how the system may change
- 2050 – a year further into the new state with much higher electricity demand (50% higher ex Tiwai than 2020)

We assess volatility with a range of measures because no single indicator gives a complete picture

- Mean/median – differences provide a measure of price level and degree of skew
- Standard deviation - provide a good summary of price dispersion – these are calculated for annual, quarterly, monthly and weekly average prices
- Standard deviation / mean expressed as % - provides a sense of relative variability which is important because the mean level of price is not constant
- Price duration curves - provide a pictorial summary
- Chronological charts - provide information on periodicity
- Box and whisker plots – provide a range of dispersion measures

Methodology

Physics + **Economics** = **Possible price structures**

- Focus on demand/supply balance in each hour
- Use 'residual demand' as measure of supply/demand balance (i.e. total demand – intermittent supply)
- Examine how shape of residual demand will change under 100% renewable electricity
- Account for flexibility limits – physical and informational

- Project future demand for 2035 and 2050 based on information about electrification, population growth etc.
- Account for thermal retirements, existing and committed new generation and expected roof-top solar, distributed batteries, smart EV charging, and potential demand response.
- Iteratively add new generic supply of each type (wind and solar, grid batteries, green peakers, geothermal).
- Simulate the operation of the system over many weather (hydro, wind, solar etc.) years to assess the levels of shortage and demand response, green peaker use and spill and the value of each type of new supply.
- Continue adding new supply until the expected market value of each type covers its fixed annualised investment and operating costs (i.e. simulate market-based investment).
- Undertake sensitivities to see effects if there is under/over investment

- Examine the nature and volatility of spot prices that emerge, within the day, over the year and from year to year as a function of inflow/wind/solar variation.
- Explore the sensitivity to:
  - balance of supply and demand
  - different water value contours
  - level of flexible supply (e.g. batteries, demand response etc.).
- Explore trends in the GWAP/TWP ratios for each type of new supply as a function of the level of intermittent supply (2020, 2035 and 2050).
- Assess any issues that arise regarding the new investment signals, operational efficiency and security.

Revenue adequacy in 2035 and 2050 for new plant can be achieved in 100% renewable reference case scenario

The chart shows the gross margin in $/kW/yr earned by each type of plant ranked from highest to lowest.

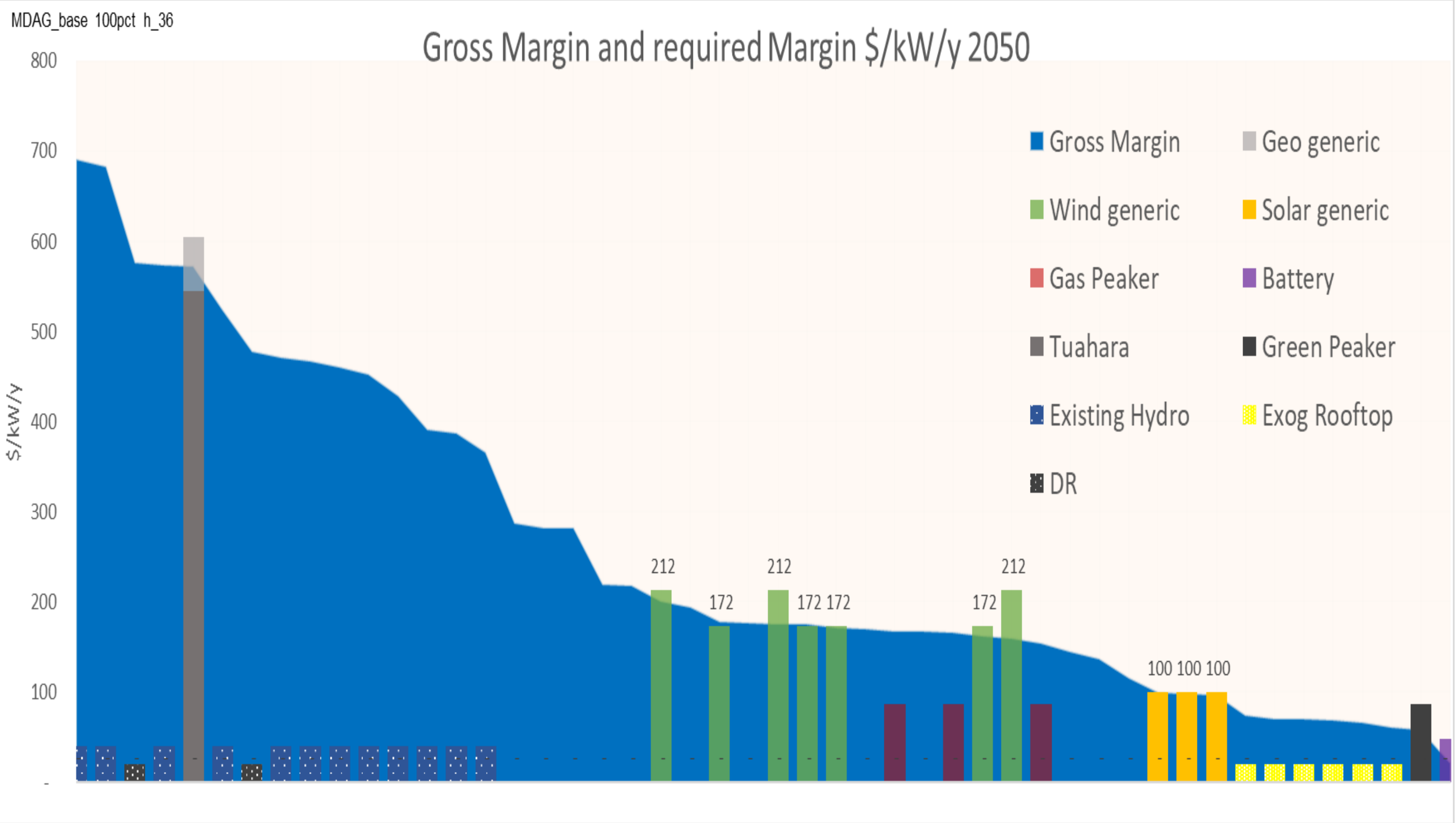


Chart explanation

- The chart shows the gross margin in $/kW/yr earned in the spot market by each type of plant ranked from highest to lowest on the x axis.
  - This is derived from the full simulation model by week and time zone averaged over 86 weather scenarios.
  - Gross margin = spot revenue minus assumed SRMC.
  - This is calculated for actual new plant and for a notional very small new plant where none is built yet.
- The columns show the gross margin required to cover fixed operating costs and to provide a 7% nominal post tax return on capital.
  - There are several generic wind and solar options with different locations and profiles.
  - Geothermal supply is assumed to be limited.
- The methodology involves progressively adding new capacity of the different technology and location until the marginal spot gross margin just covers its fixed costs.
  - This is an attempt to mimic competitive new entry by private investors with a range of different plant technologies.

Note: It is assumed that batteries receive revenues for ancillary services, distribution and transmission support etc. and so only require 60% recovery of fixed costs from wholesale market price arbitrage. Noting that the cost of batteries up to 12-hour duration is expected to decline rapidly as a result of technology improvements and scale (driven by automotive demand).

Green peakers are also assumed to receive revenues for transmission and distribution support and from “insurance” premia and so only require 80% capital recovery from wholesale prices. Noting that it may be possible to convert existing gas peakers to a new “green” fuel as a lower capital cost than building new.

Simulation Approach

Simulation approach

- The simulation is carried out week by week over 86 historical weather years. The lake levels at the end of each simulated year are used as the starting levels for the next simulated weather year.
- Within each simulated week the available supply resources (including demand response, batteries, green peakers, intermittent supply and offered hydro) are dispatched to meet the time profile[1] of demand in each island at minimum cost.
- Energy and capacity constraints and round-trip efficiencies are accounted for as well and inter-island transmission constraints and losses.

Note: 1) the simulations can use a time profile of 168 periods corresponding to hours within the week but most of the results reported here use 36 time periods corresponding to a typical work day by hours and a typical non-work day by 2 hour blocks.

Hydro modelling

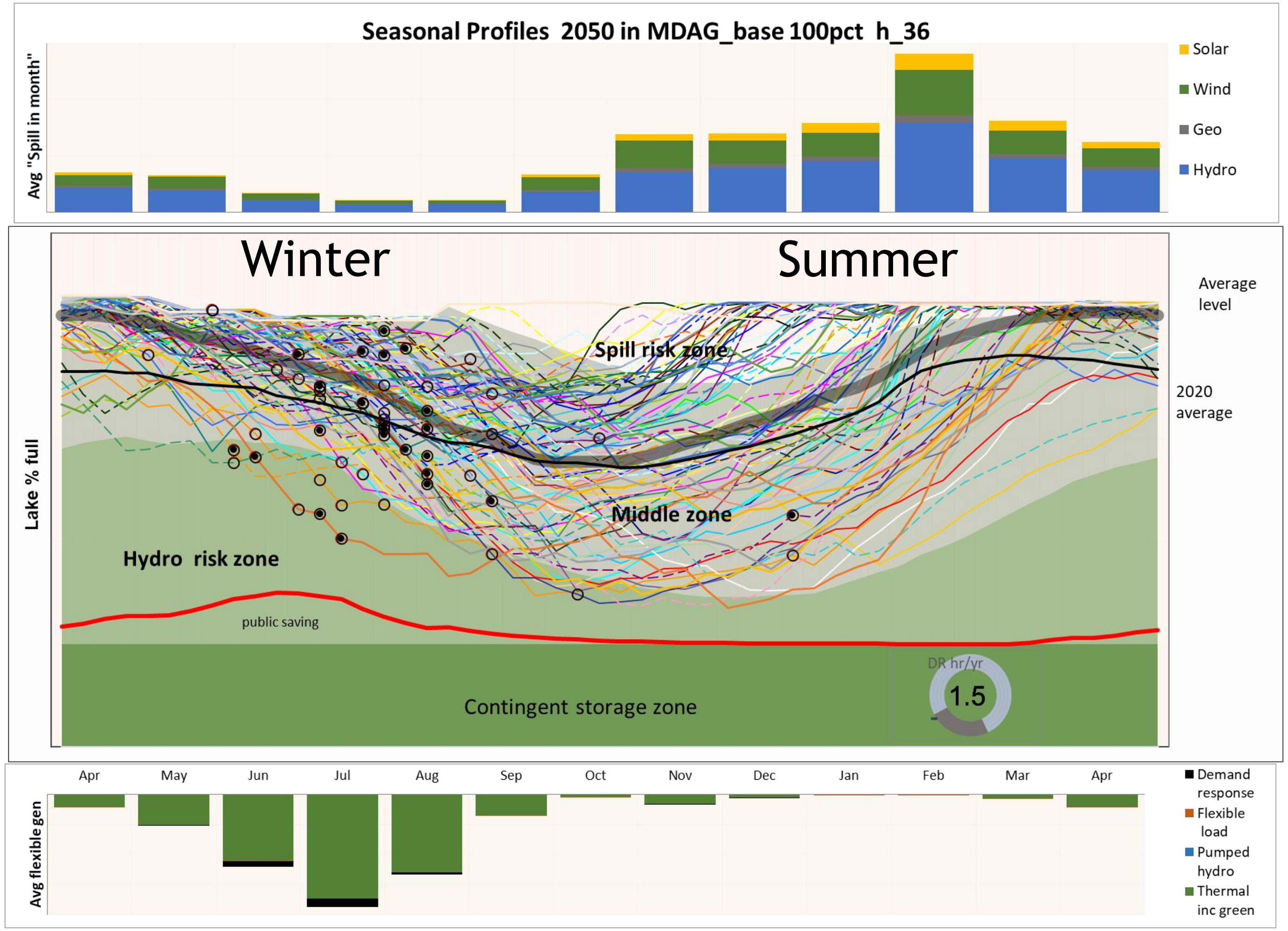
- Assume that hydro water values reflect the short run marginal cost of renewables when lakes are full and the risk of spill is high, and the cost of demand response when lakes are low, and the risk of shortage is high.
- It is noted that, in the absence of significant thermal plant, water values contours for intermediate lake levels have limited impact within each year.
- It is proposed that these intermediate values are set at a level that promotes efficient levels of investment in new renewable energy – trading off spill against risks of shortage.
- The water values contours are profiled to ensure that dry years are covered.
- Undertake sensitivity to test different water value functions.

Intermittent supply and demand

- Include hourly wind and solar profiles based on historical data or synthetic profiles over the period 2000 to 2018.
- Include daily and weekly profiles based on history for underlying demand and for EV charging.

The model is producing sensible looking lake operation and dry year security under the 100% renewable reference case, but with higher "spill" than now

2050 - 100% renewable reference case - showing the trade-off between spill and use of flexible resources over the year



Note: 1) Red circle = green peaker required in week, Black circle = green peaker > 50GWh in week, Black dot = demand response required.

Chart explanation

- The offer price contours reflect the cost of spill when lake levels are full, and the risk of spill is high. They reflect the cost of green peakers, demand response and shortages when lake levels are low, and the risk of supply is higher.
- The guidelines are shaped to ensure that, with the level of new renewable investment, the risks of running into the contingent zone in the worst simulated sequence is very low.
- For intermediate lake levels the offer prices are set to achieve a new entry equilibrium whereby new geothermal/wind/solar are able to achieve revenue adequacy and hydro storage levels are able to be maintained at a sufficiently high level prior to winter to manage dry year risks, without a major new pumped hydro investment.
- Dry year security can be maintained with existing levels of storage capability under 100% renewables via additional renewable build to ensure that lake levels are adequate in all but the worst sequence.
- Renewable build is also driven by the need to avoid "capacity" and green peaker costs in winter days with low wind.
- Spill occurs when lakes are filled prior to winter and there is high inflow and or wind/solar.
- The red and black circles[1] and black dots show weeks in which either green peakers or demand response are required. Most of these are winter weeks with low wind. Only a few are related to low hydro periods in 2050.

CALIBRATION

The impact of going to 100% renewables can be assessed relative to simulated outcomes for the 2020 system as this matches history relatively well.

To assess the performance of the modelling approach we simulated the operation of the system as it was in 2020 and compared simulated measures of price volatility with historical patterns

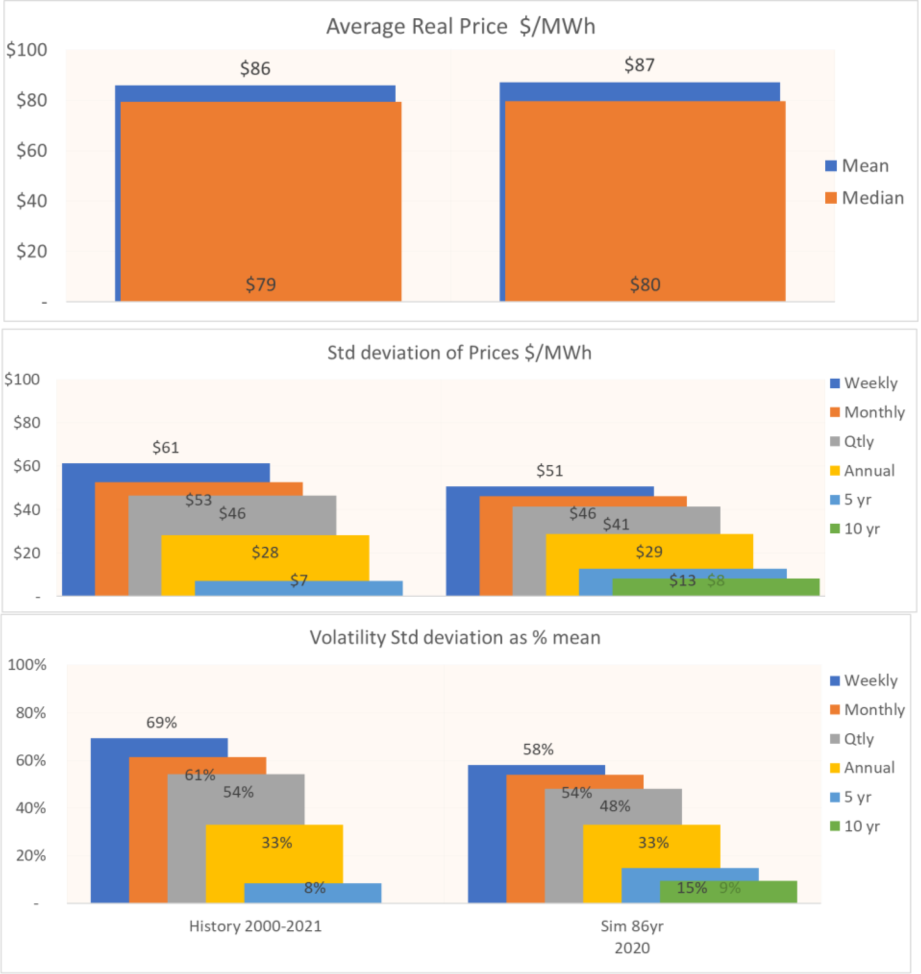
- **We have carried out a simulation of the system as it was in 2020 (with normal demand, Tiwai and existing plant available) over the full set of 86 sampled weather (hydro/wind/solar/demand) conditions.**
  - This simulation has been calibrated to achieve an average time weighted price level roughly consistent with the average real price level over the last 20 years of actual data.
  - Note that, in both cases the mean price is higher than the median, as expected given the skewed nature of electricity prices.
- **This benchmark simulation can be compared with historical levels of price volatility over 21 years of history from 2000 to 2021.**
  - The standard deviation of simulated annual average prices is very close to the historical average ($29 versus $28/MWh).
  - The std deviation of simulated results is generally a bit lower for other time frames. This is to be expected given that the historical data includes both system and weather effects, whereas the simulation only includes weather.

- **Modelling health warning:**
  - The model used here focuses on the simulated weekly variations of weather conditions by time zone and does not attempt to fully model the fine detail of price formation for every half hour.
  - The model assumes a cost minimising approach with limited storage resources being dispatched with foresight subject to energy constraints.
  - This is a suitable approximation for assessing physical outcomes but does not replicate short run within-week price fluctuations very well. Within-week prices tend to jump between flat bands. The evolution of uncertainties during the week and the need to manage these through changes to hourly offers will create more hour-on-hour variation and will smooth out the transitions between the model price bands.
  - Ideally the model could be enhanced to include a 2-step market clearing, one based on a forecast dispatch which is modified as necessary to account for changes as they become known during the week. This has not been done and so we have focused our assessments of price volatility etc. on the average results for the week rather than for each hour or half hour.

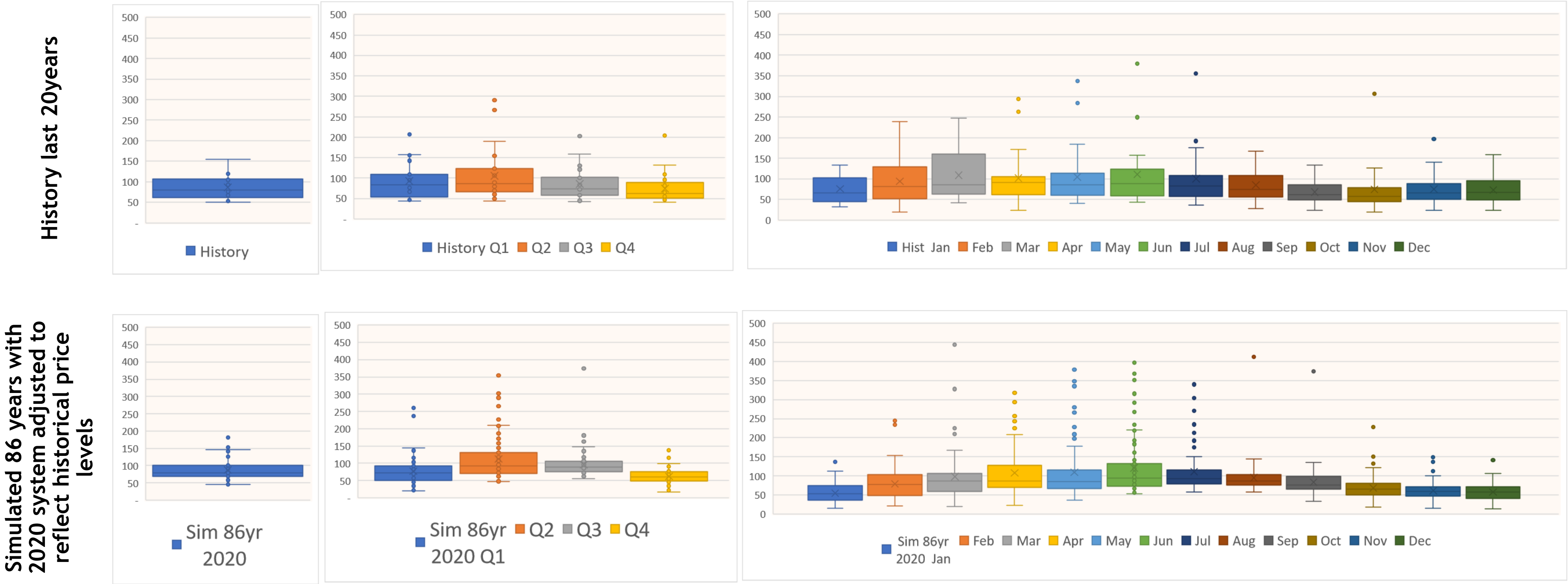
Price level and volatility measures on different time frames.

Actual history
21 years of weather and many other changes – e.g. tx outages, system configuration, fuel shocks etc.

Simulated 2020 system
86 years of weather



Box and whisker plots for annual, quarterly and monthly prices show that the modelled 2020 price distributions over 86 weather years are relatively consistent with observed spot prices over the last 20 years.



The charts show the inter-quartile range as the box, the median as the line within the box. Outliers are defined as above or below the box plus or minus 1.5* the interquartile range. The whiskers go from the minimum to maximum excluding outliers.

Note that the lower chart includes simulated results for 4 times as many weather years as the upper chart, hence the number of outliers is proportionally larger.

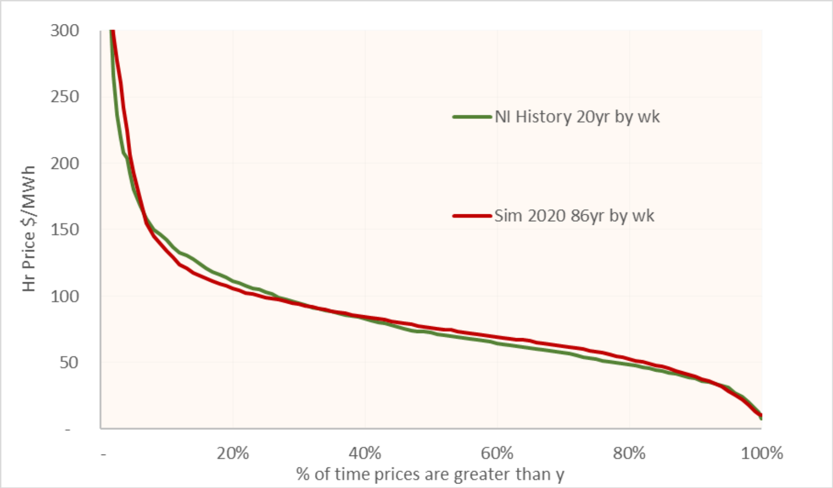
Calibration of Price Duration Curves (PDC)

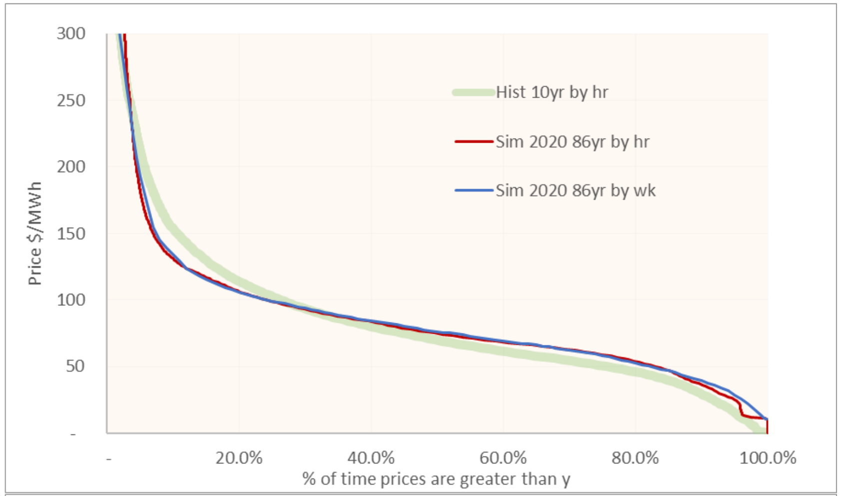
The charts show that the simulated weekly price duration curves for a 2020 system over 86 years are very close to the historical weekly PDC over 21 years. Thus the 2020 86 years simulation provides a relevant benchmark for this study.

Comparing history with simulated prices based on 2020 system

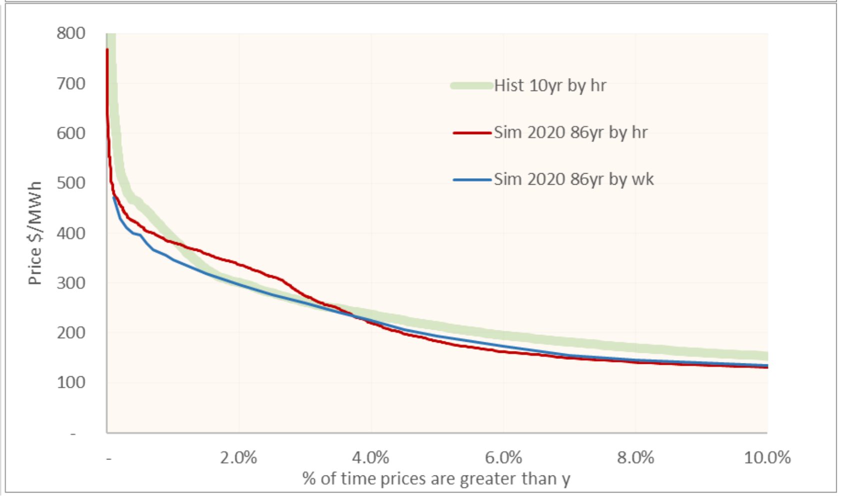
Comparing PDC results on a weekly and hourly basis

Bottom of PDC





Top of PDC (0-10% of time)



Commentary

- **The chart shows simulated 2020 Haywards prices ranked from highest to lowest over simulated 86 weather years by week and by hour. These are the Price Duration Curves (PDC).**
  - As can be seen the simulated weekly PDC and the simulated hourly PDC are very similar except for at the very bottom and top of the PDC.
- **These price duration curves can be compared with historical price duration curves covering the last 10 and 20 years.**
  - The simulated weekly PDC is very close to the historical weekly PDC except at the very top 1-5%. The simulated PDC is higher for the top 3%, as expected from a simulation over a much greater number of weather years.
- **The charts on the right show the comparison between the simulated PDCs on a weekly and hourly basis.**
  - The simulated weekly PDC is close to hourly PDCs, except being smoothed around the elbow on the bottom 10% and being slightly lower for highest 5% of prices.

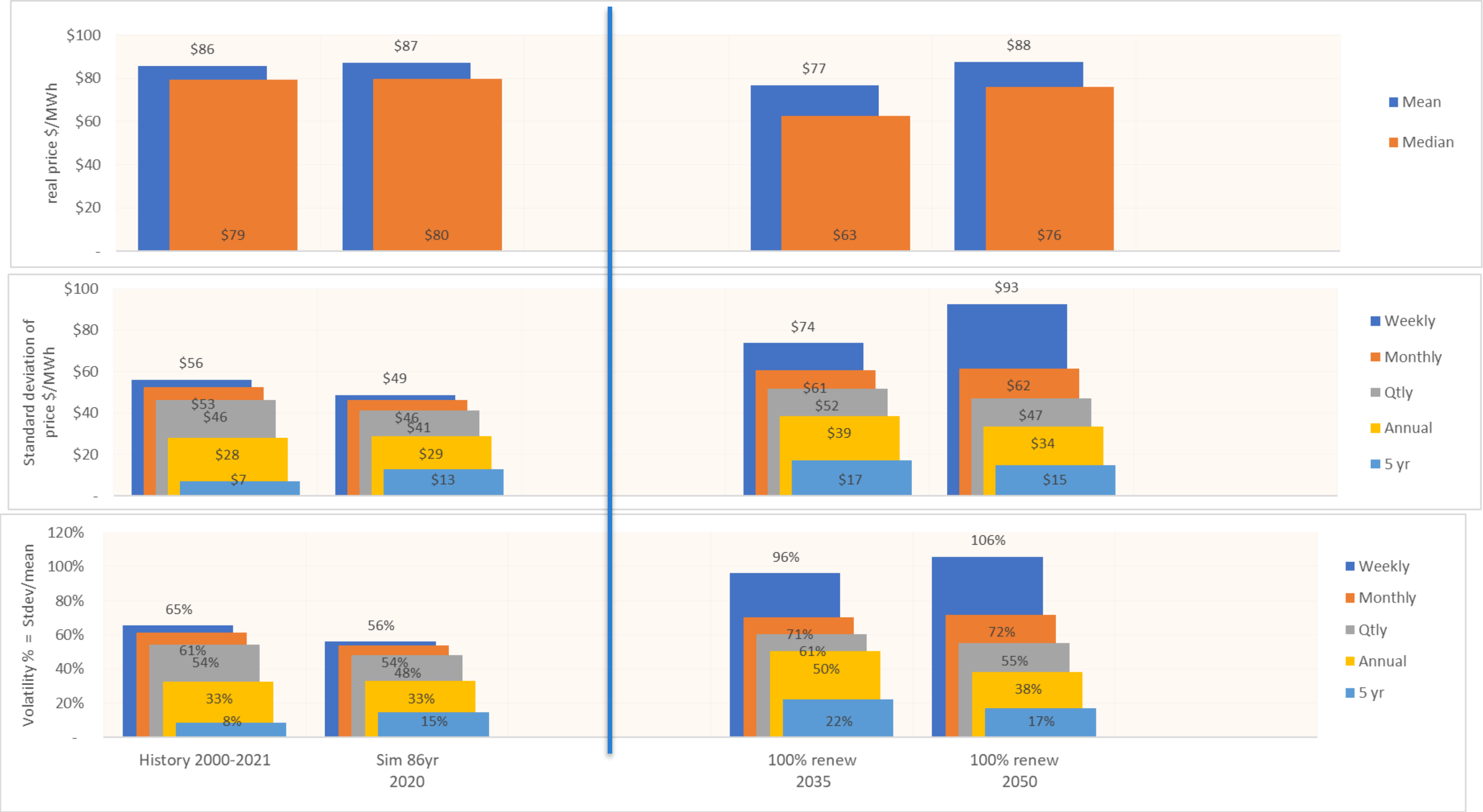
SUMMARY RESULTS - MEASURES OF PRICE VOLATILITY

Reference case

Overall measures of price[1] volatility on annual, quarterly and monthly time frames

The price volatility over 86 weather years in a simulated 2020 year is similar (a bit lower) to the historical levels over the last 20 years. Future price volatility is expected to increase moderately as we decarbonise.

Last 20 years and simulated for 86 years | **100% renewable reference case**



Note: 1) In this report prices are time weighted averages unless specified otherwise.

Commentary

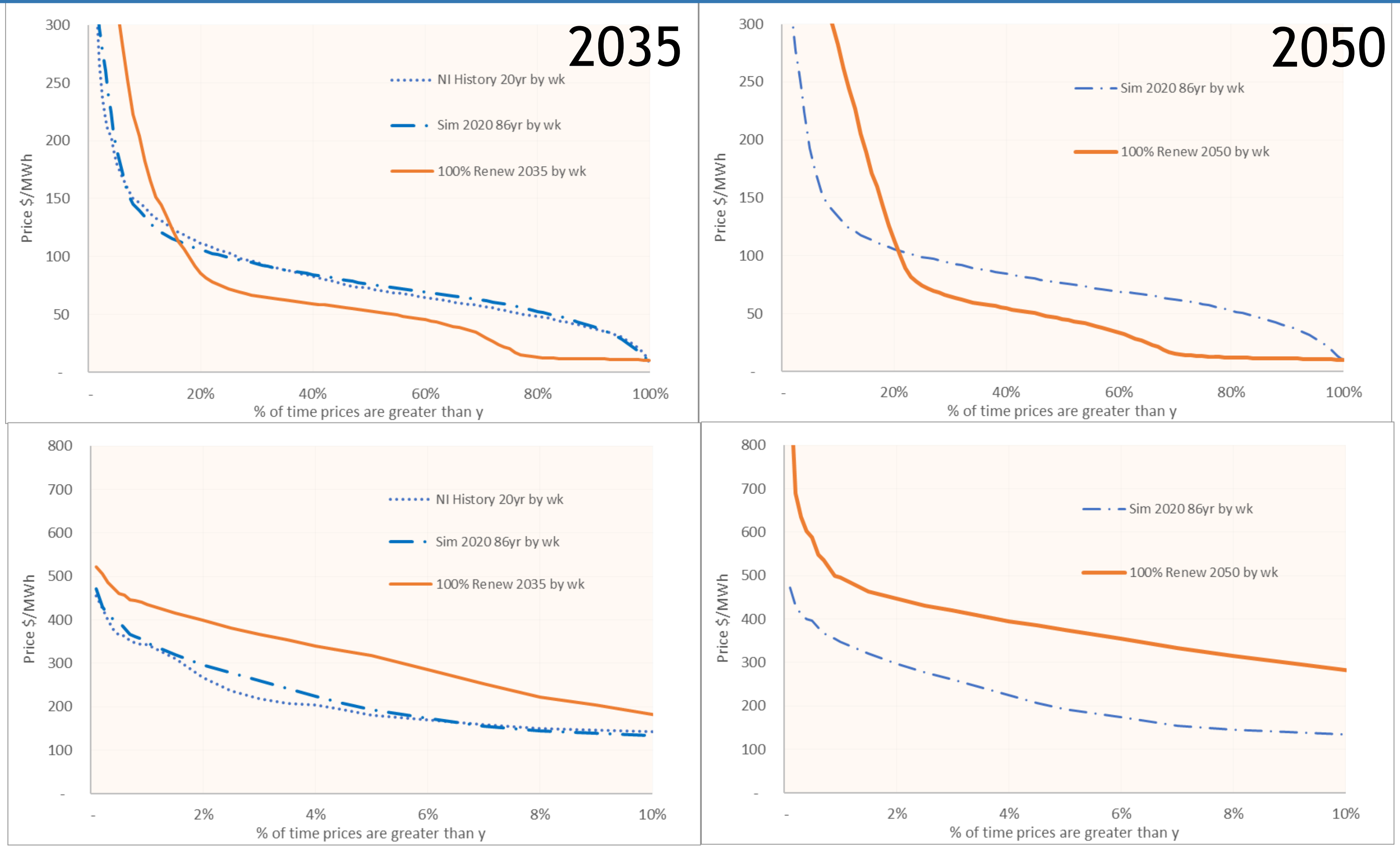
- **The chart shows the measures of price volatility on a weekly, monthly, quarterly and annual time step.**
  - We have not produced daily and hourly volatility measures as the modelling is being done on a weekly time step with broad time zones within each week.
- **The historical measures are compared with the history from 2000 to 2021 (21 years) and a full model run calibrated to 2020 conditions with Tiwai and historical price levels.**
  - The model runs include 86 sampled weather (hydro/wind/solar/demand) conditions.
- **2 separate years are modelled in the future, 2035 and 2050.**
  - These represent increased demand levels.
- **The middle column is based on a generation equilibrium scenario.**
  - This has 100% renewables, but with the possibility of very expensive green peakers being available as a last resort firming option.

Weekly PDCs - with 100% renewables reference case

There is a significant change in the PDC as we decarbonise. Much longer periods of low prices reflecting the risk of spill are expected, balanced by longer periods of high prices. On average, the PDCs enable new investment in a mix of geothermal, wind and solar and reserves (batteries, load management and peakers) to maintain security in adverse weather.

Bottom of PDC

Top of PDC (0-10% of time)



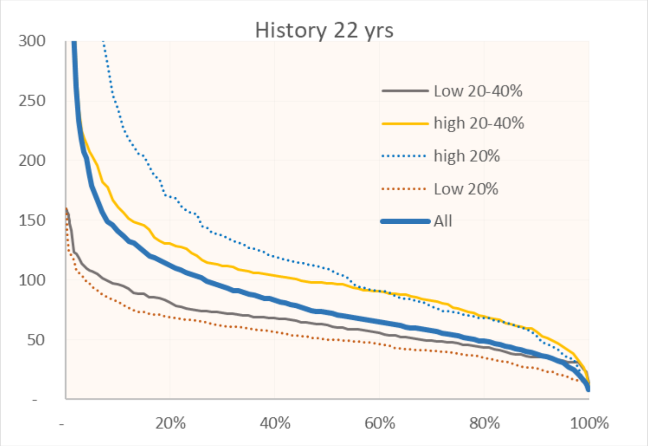
Commentary

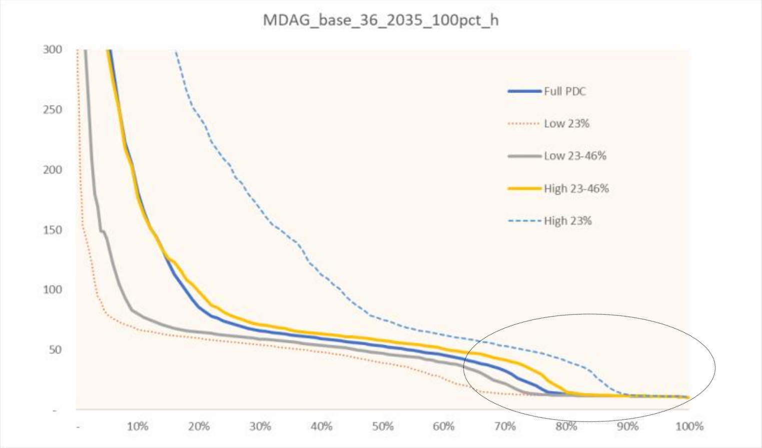
- The chart shows Haywards prices ranked from highest to lowest over simulated 86 weather years by week and time zone.
- The charts also provides the historical price duration curves covering the last 20 years, and simulated 2020 prices over 86 weather years as comparative benchmarks.
- As can be seen the most significant feature is the long periods of prices around $10-$20/MWh. This is a consequence of meeting dry year security by building extra renewables and resulting in more spill.
- The bulk of the time prices are around the cost of new energy supply ($60-$80/MWh).
  - This is set by hydro operators offer curves during periods when lake levels are in the middle zone.
- The top of the price duration curve is higher and fatter, reflecting the higher risk of capacity issues during periods of low wind when hydro capacity is at its maximum.
  - In these periods prices reflect the cost of green peakers or the cost of flexible demand response.

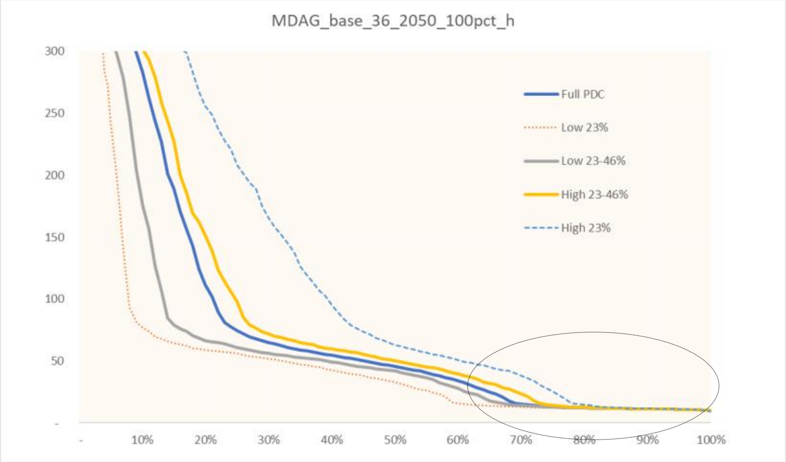
The PDCs vary by weather year groups as shown in the charts

Historical	100% renewable Reference case - 2035	100% renewable Reference case - 2050
History	2035	2050

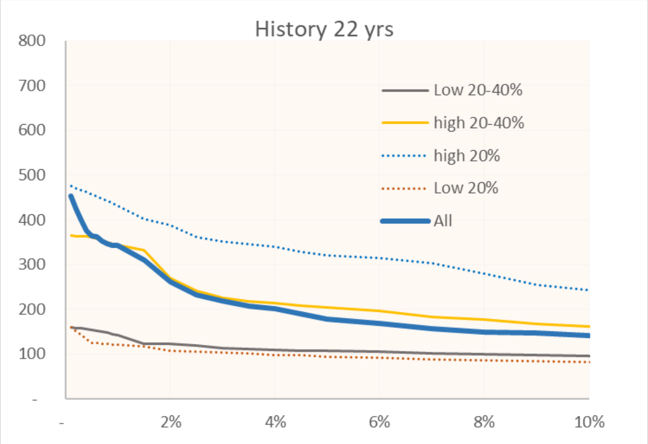
Bottom of PDC

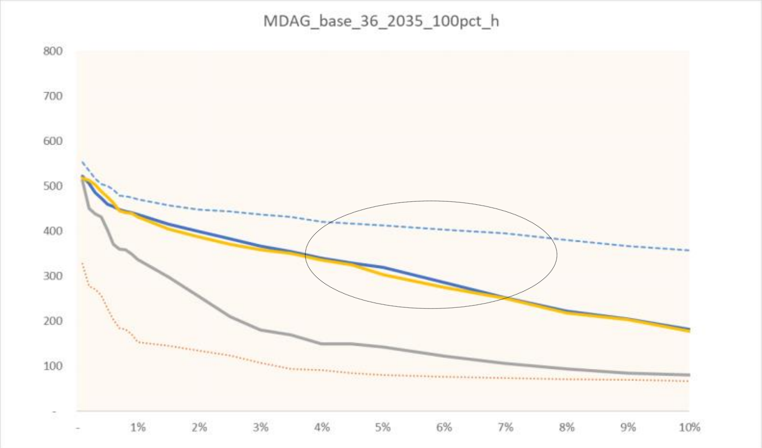


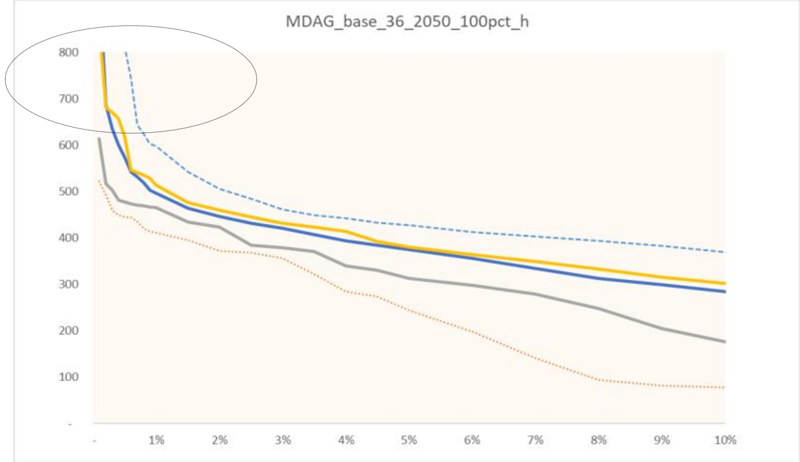




Top of PDC (0-10% of time)

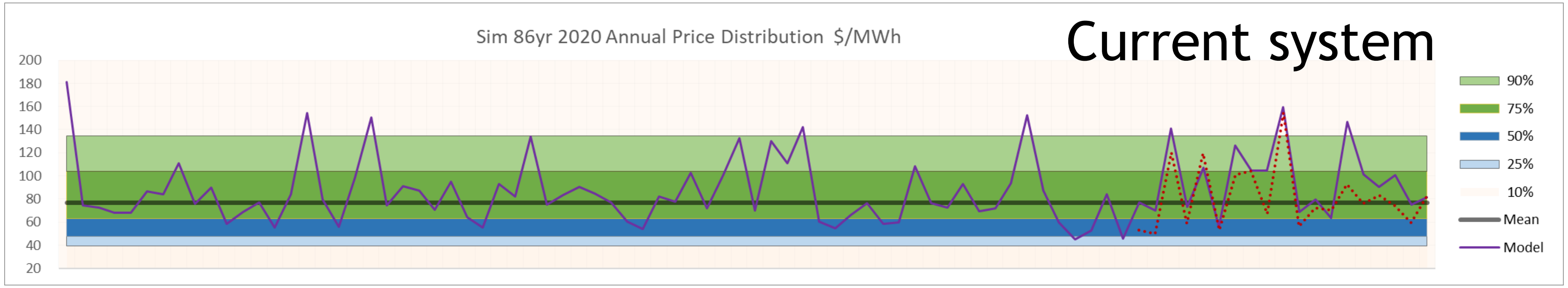






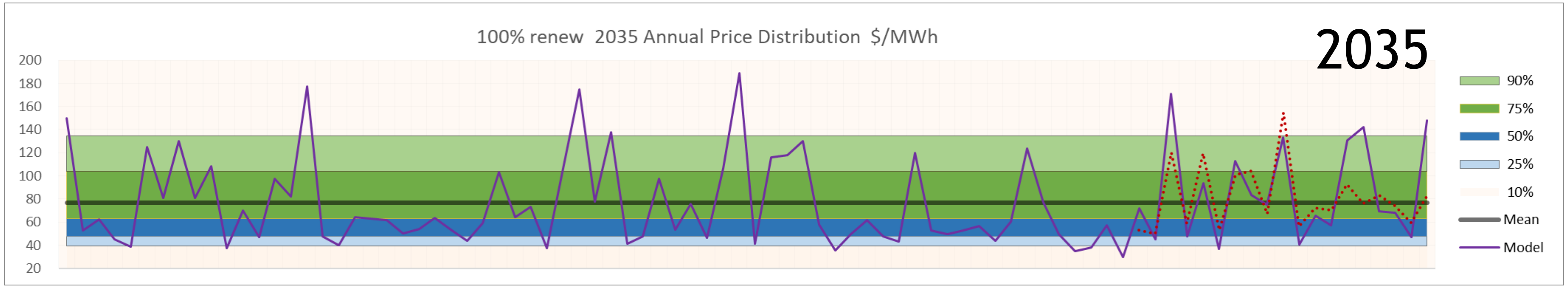
Annual price distributions are progressively more volatile under 100% renewables

$29 std
33% vol



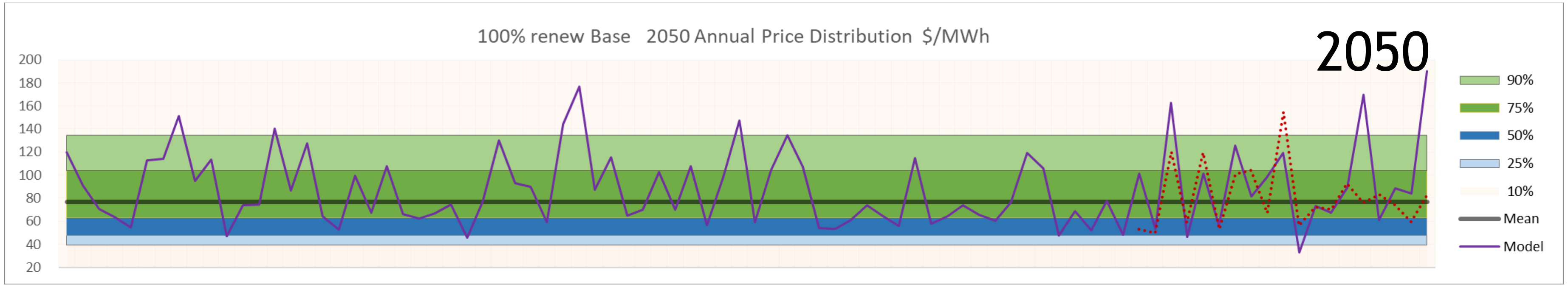
The modelled distribution of annual prices over 86 weather years has a very similar volatility to the last 20 years of CPI adjusted annual spot prices.

$38 std
49% vol



The modelled 2035 distribution of annual spot prices has a higher standard deviation and volatility relative to the last 20 years, but general nature of price variations is similar.

$41 std
45% vol



The modelled 2050 distribution of annual spot prices is higher again in 2050. This is driven by the higher level of intermittent supply on the system.

Stdev = standard deviation of average annual prices over 86 weather years
Vol = Stdev/Mean

Note that the starting point for the sequential set of weather years used in the simulation in each future year varies, so the annual fluctuations are not expected to align in each chart.

Monthly price distributions by hydro sequence show changes in the seasonal shape

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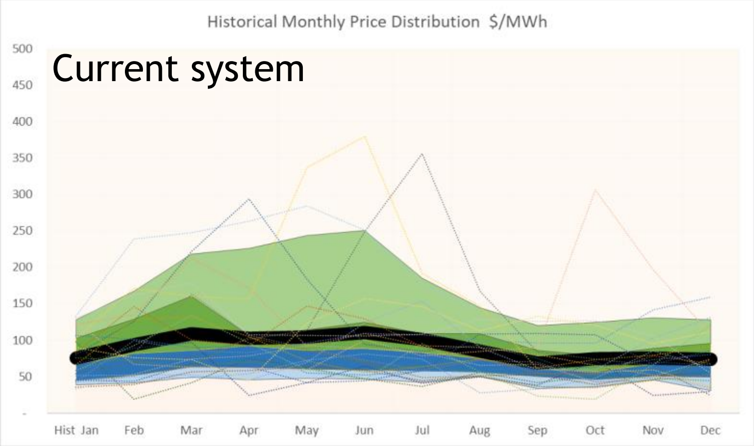
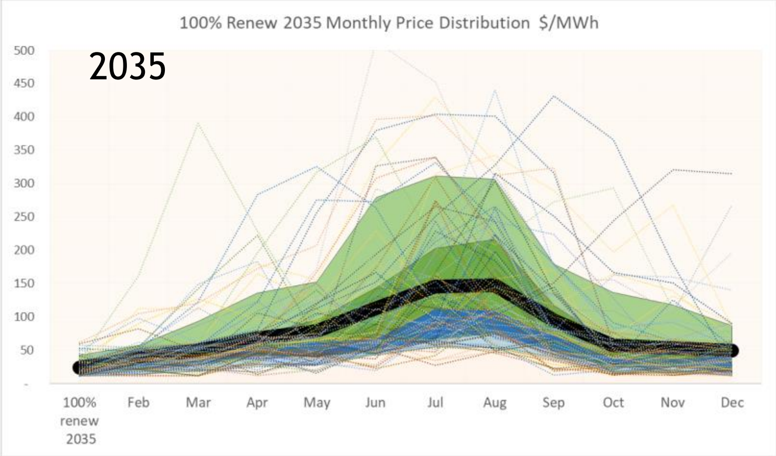
The historical distribution of monthly real prices from 2000 to 2020 is illustrated below. This is like the 2020 simulated modelling results shown in the lower chart.

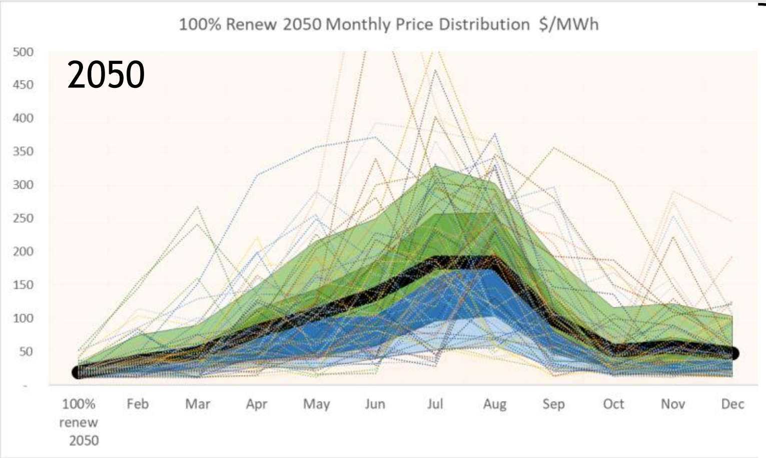
The modelled distribution for 2035 shows a stronger winter seasonality which is shifted from early to later winter. Prices prior to winter are lower as lakes need to be held high to cover dry year risk. This means that the risk of spill during high inflows, strong wind or sun are increased and prices are low.

Modelled distribution for 2050 shows a similar shape to 2035, but price volatility in winter is greater. This is caused by higher intermittent supply and more frequent capacity constraints requiring green peaker use and demand response during sustained low wind periods when winter demand is high.

History last 20year

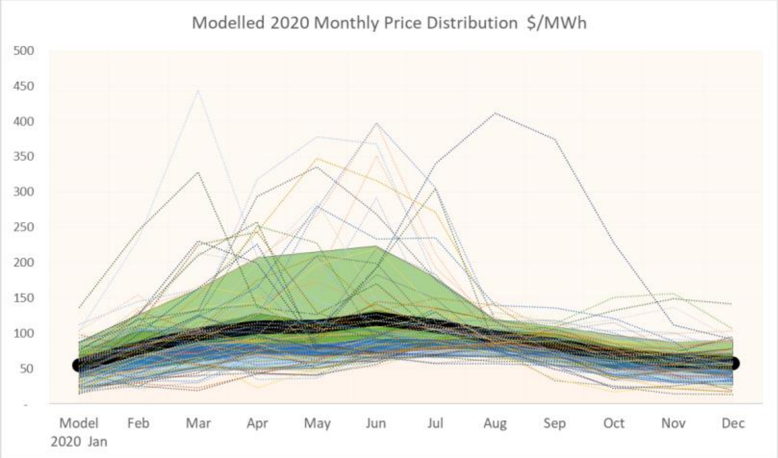


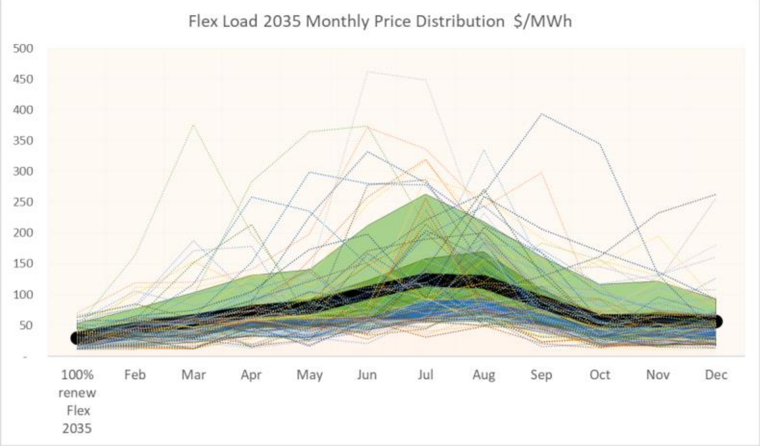


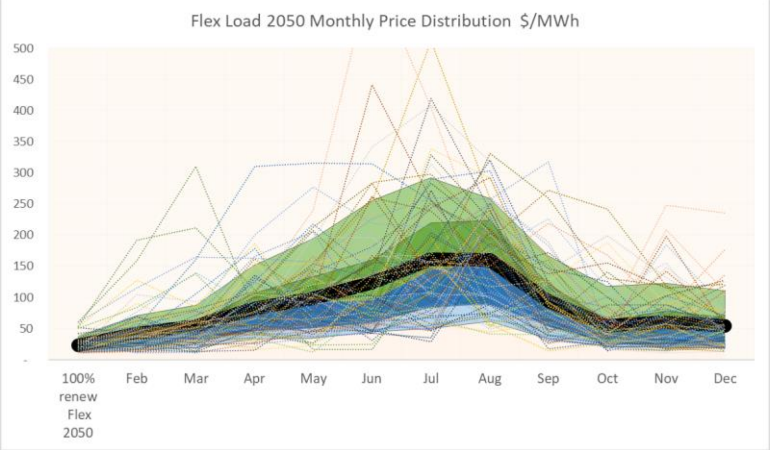


100% renewable reference case

86 weather years simulated for 2020

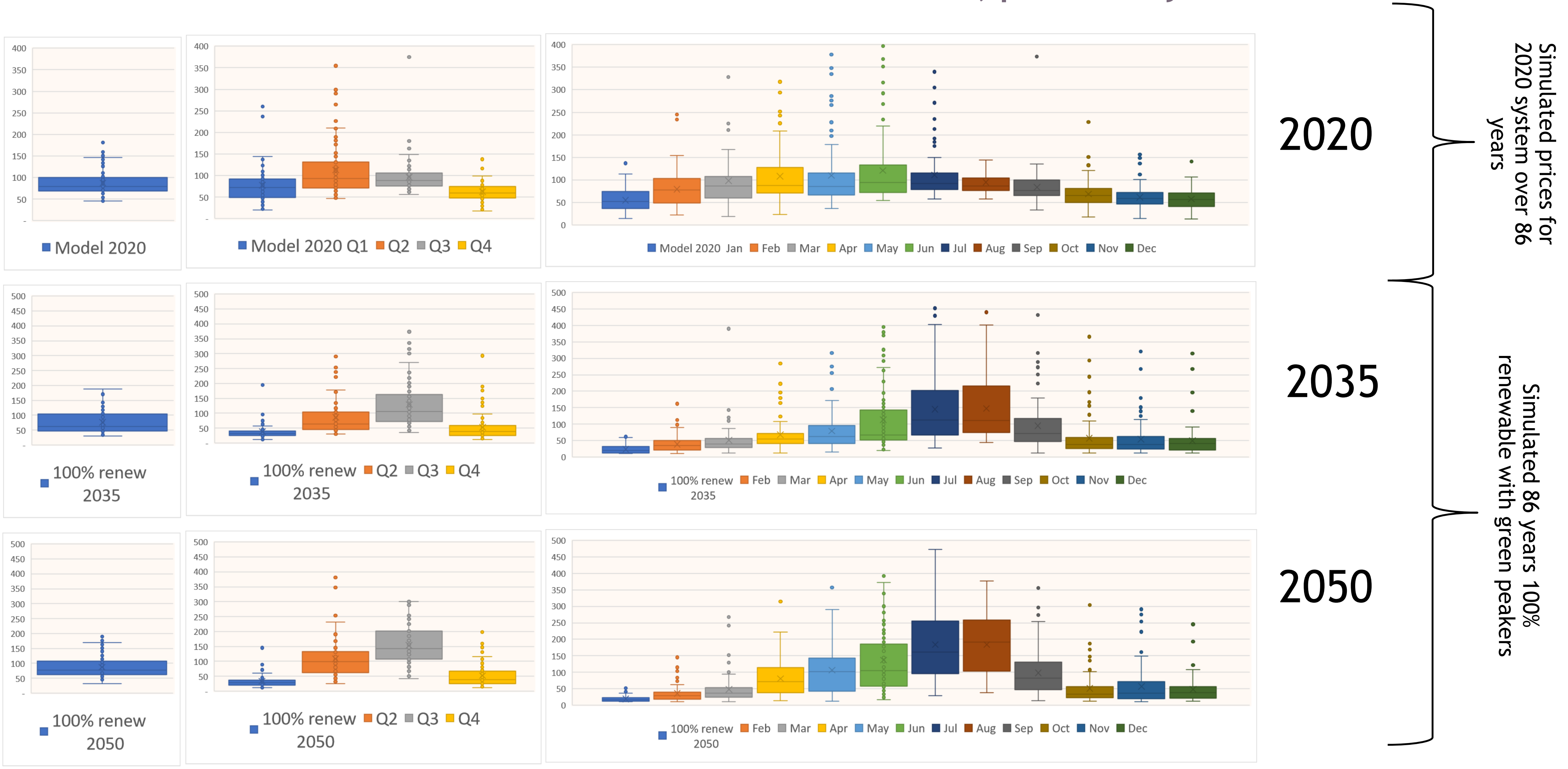






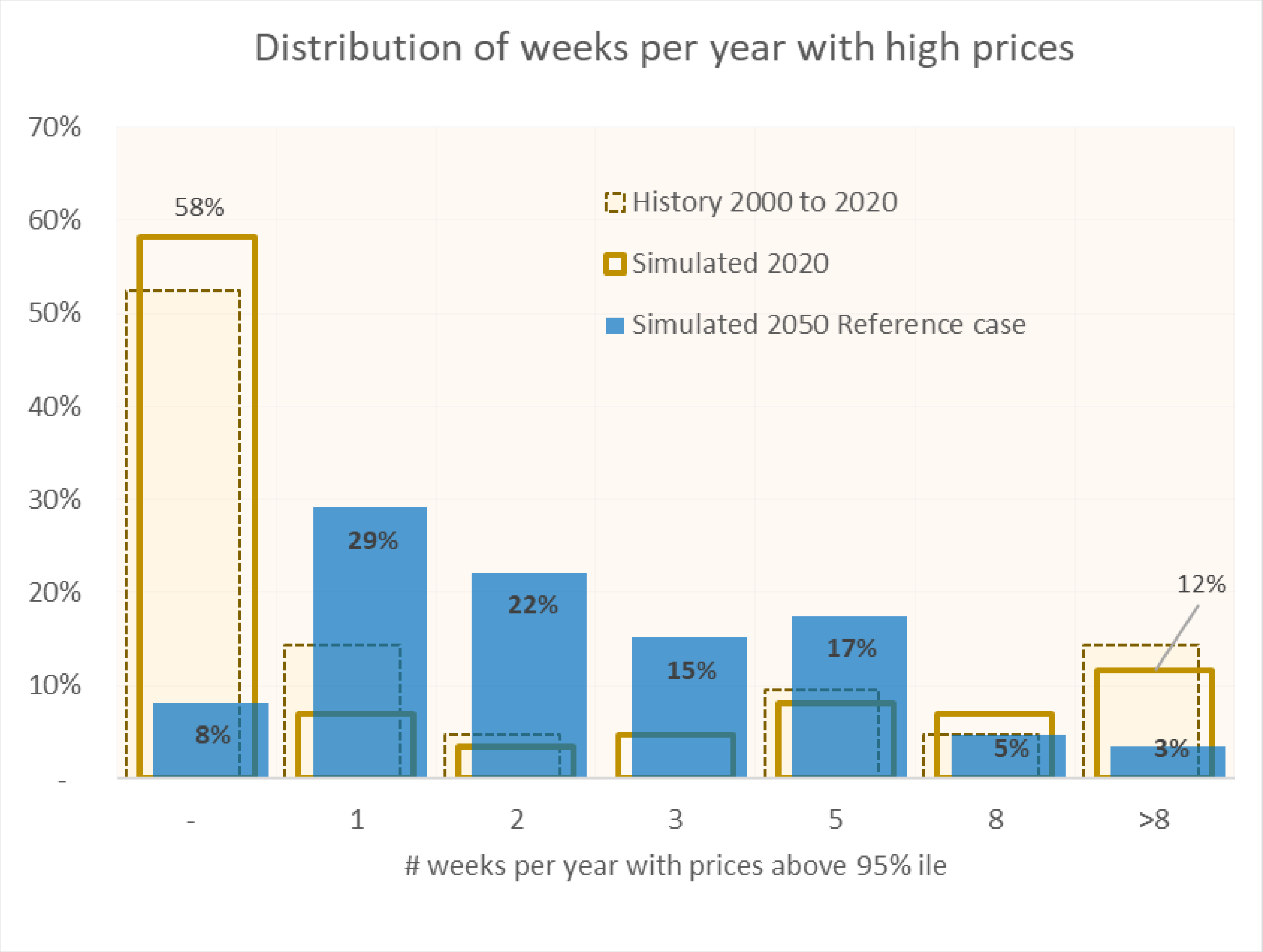
100% renewable with extra flexible load

Box and whisker plots for annual, quarterly and monthly prices indicate that price distributions become more wider and more skewed over time, particularly in winter



The distribution of weeks with high prices is likely to move from a U shape to a more "normal" or inverted U shape

Distribution of high priced weeks per year

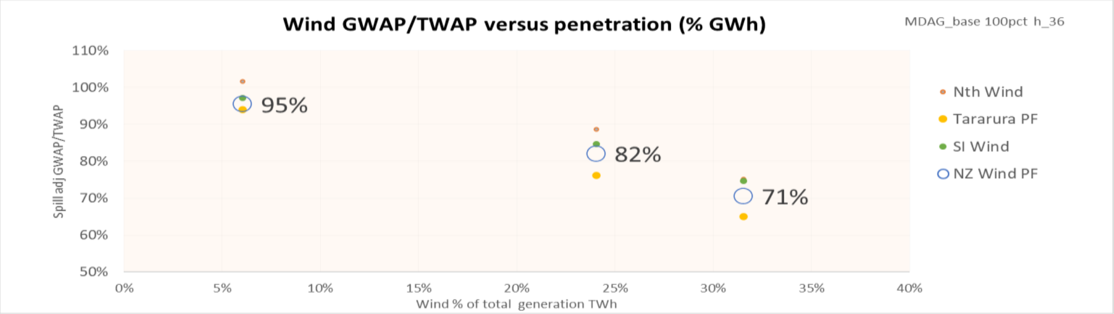


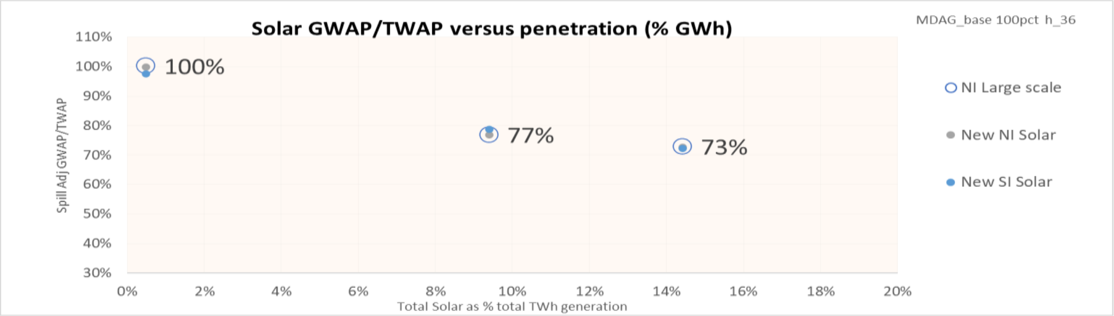
Commentary

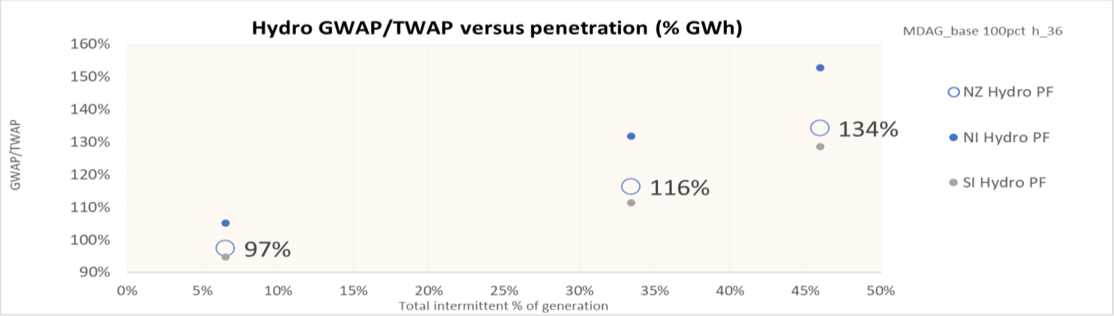
- **The chart shows the distribution for the number of weeks each year with high prices (taken to be those with a price level above the 95th percentile).**
- **The unfilled blocks are for the history and status quo system:**
  - **These show:**
    - a large number of years with no abnormally high priced weeks,
    - a significant number of years with a large number of high priced weeks (dry years), and
    - A lower number of years with just a few high weeks.
- **The blue bars show the simulated situation in 2050. This has:**
  - **Relatively few years with either zero or->8 weeks of high prices, and**
    - the majority of years with just a few weeks of high prices ("dunkelflaute" events).
- **This change reflects the increased relative risks of capacity shortfalls in the winter (due to low wind/solar) and reduced relative risks of sustained dry year events.**
  - **Note the dry year risk remains similar, but capacity risks from low wind/solar are rising so the relative balance between risks is changing from being predominantly dry year based to more frequent but shorter based on low wind/solar.**
- **This change may encourage participants to hedge their exposures more consistently.**

GWAP/TWAP factors fall for wind and solar and rise for flexible hydro

100% renewable with green peakers and reference case load flexibility







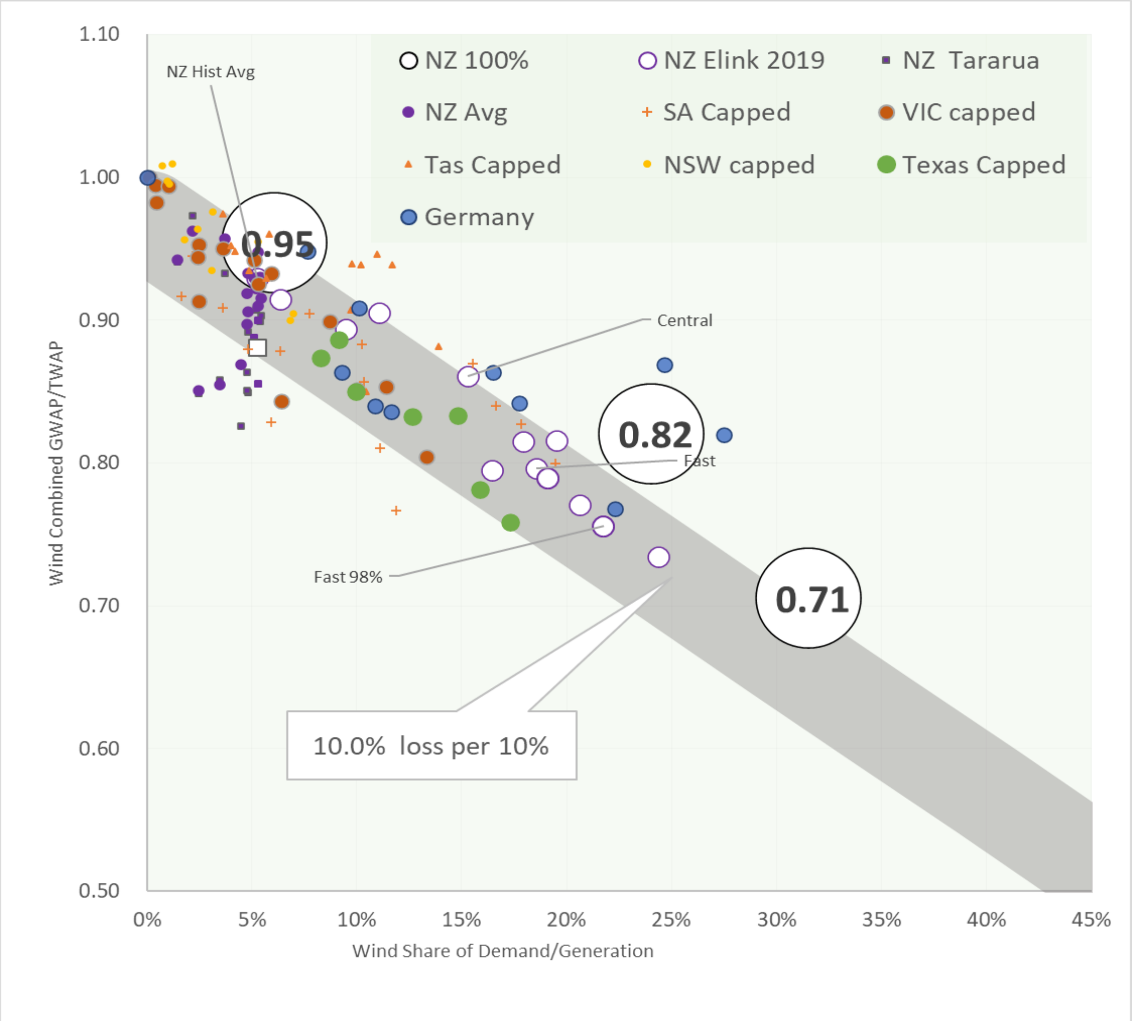
Commentary

- Wind
  - **The wind GWAP factor declines to 69% as the % of wind generation increase 4.6x from 6% to 32%.**
  - **The GWAP/TWAP factor varies by region depending on the relative correlation and size of generation in each region.**
    - The factor in the Manawatu is lower as this region has a high percentage of correlated wind, whereas the factor in the upper north island is higher as its wind is less correlated.
- Solar
  - **The solar GWAP factor declines from around 100% to 72% as the % of solar generation increases 13x from 1% to 14%.**
    - The solar penetration % of generation accounts for both rooftop and utility scale solar, but the GWAP/TWAP factors are calculated for utility scale solar only. This is assumed to have single axis tracking and so has a different profile to rooftop.
- Hydro
  - **The hydro GWAP factor increases around 36% as the percentage of intermittent supply (wind and solar) increases from 6% to over 40% in 2050.**
    - This factor varies significantly between hydro schemes, depending on location, capacity factor, storage capacity, inflow correlation and scheme flexibility.
    - Very flexible hydro will benefit if it can backup increasing intermittent supply. This will provide an economic incentive for existing hydro to adapt its scheduling and improve its capacity/flexibility where possible and where the costs are sufficiently low.
- Load
  - This is not shown, but the factor for the NI system load does not change significantly from 105% as price variations become more driven by wind/solar fluctuations rather than load as we go to 100% renewable.

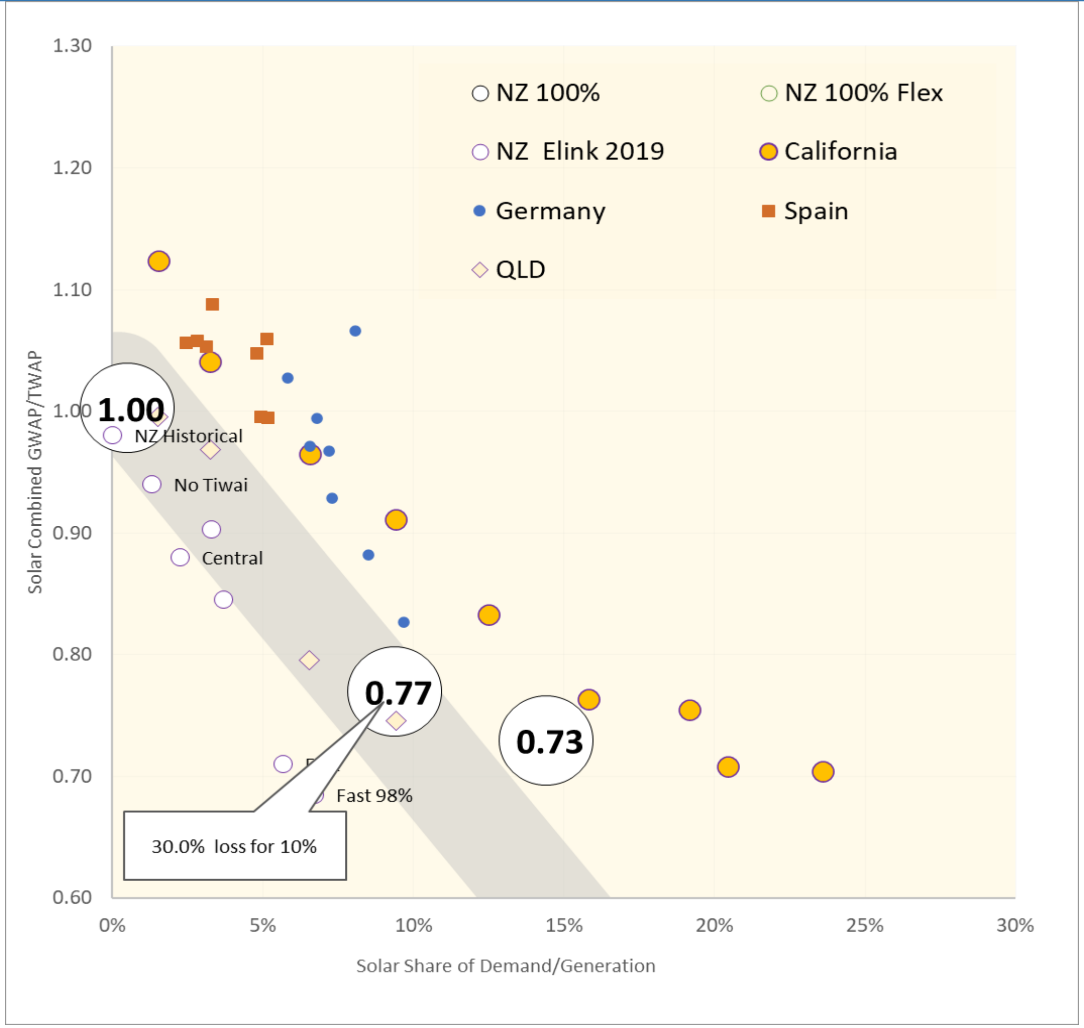
Notes: The Wind GWAP/TWAP ratios are adjusted for spill so they can be compared more easily. This means that the GWAP is expressed in terms of the potential generation before spill. The achieved GWAP/TWAP based on actual generation after spill will be higher if the wind generators offer at a non-zero price and are dispatched off when prices are lower. These GWAP/TWAP simulation results might be slightly overestimated as a result of the within week simulation approach which assumes perfect foresight for scheduling of batteries and EV load control and does not fully model the half hour to half hour independent offering.

Falling GWAP/TWAP factors under 100% renewables are not unexpected when seen in the context of international experience of markets with high levels of wind and solar

Wind GWAP/TWAP estimates are broadly in line with international experience and previous modelling. The GWAP/TWAP factors are around 0.02 higher with high levels of flexible load.



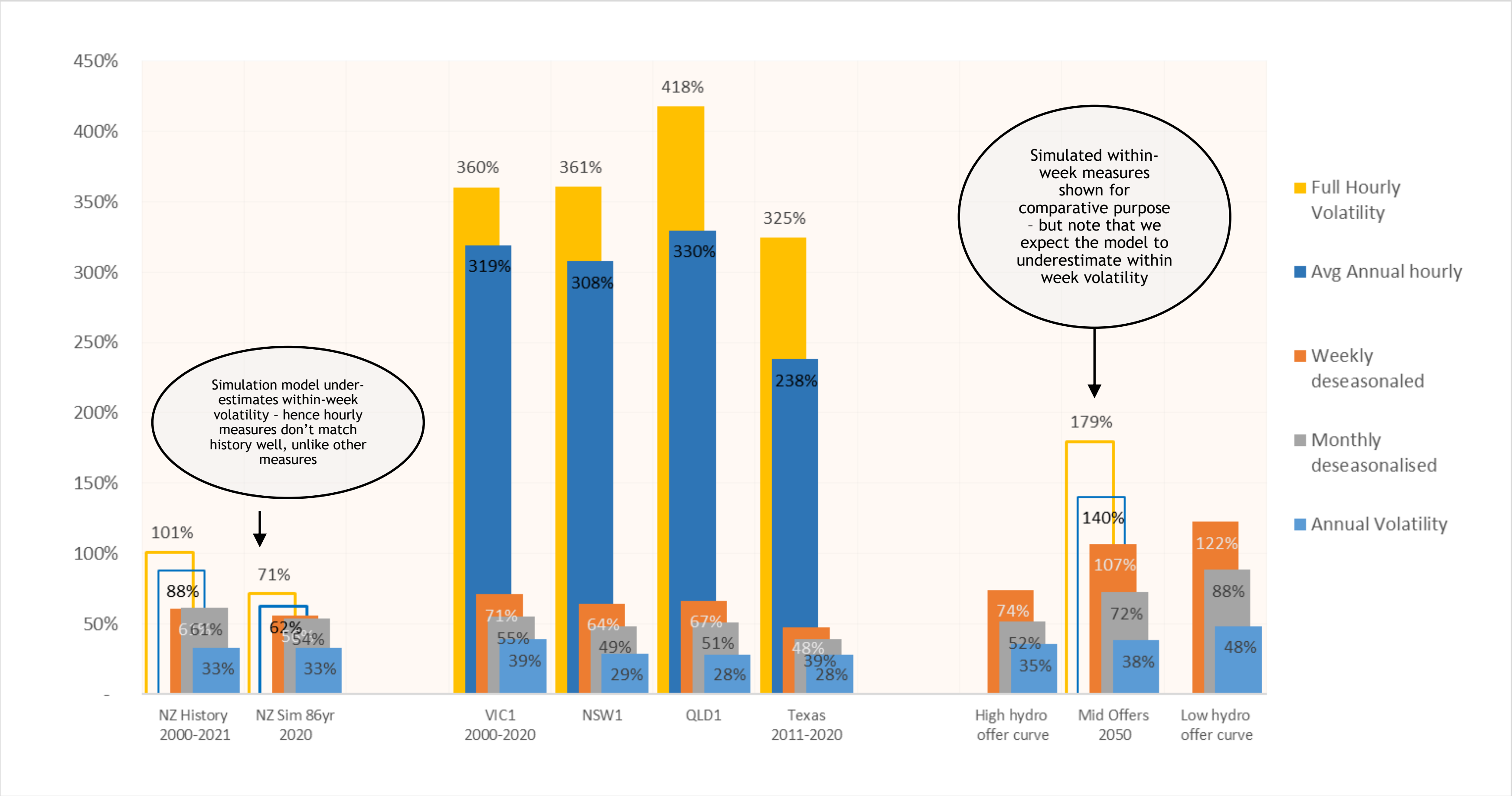
Solar GWAP/TWAP estimates are broadly in line with international experience and previous modelling, when translated to a winter peaking system. The solar GWAP/TWAP factors are higher when there is higher levels of flexible load.



INTERNATIONAL PRICE VOLATILITY COMPARISONS

NZ has had similar or slightly higher annual spot price volatility compared with the NEM and Texas (energy only markets), but substantially lower hourly volatility

The chart shows NZ historical volatility measures compared with the simulated 2020 system and several NEM regions and Texas (ERCOT)



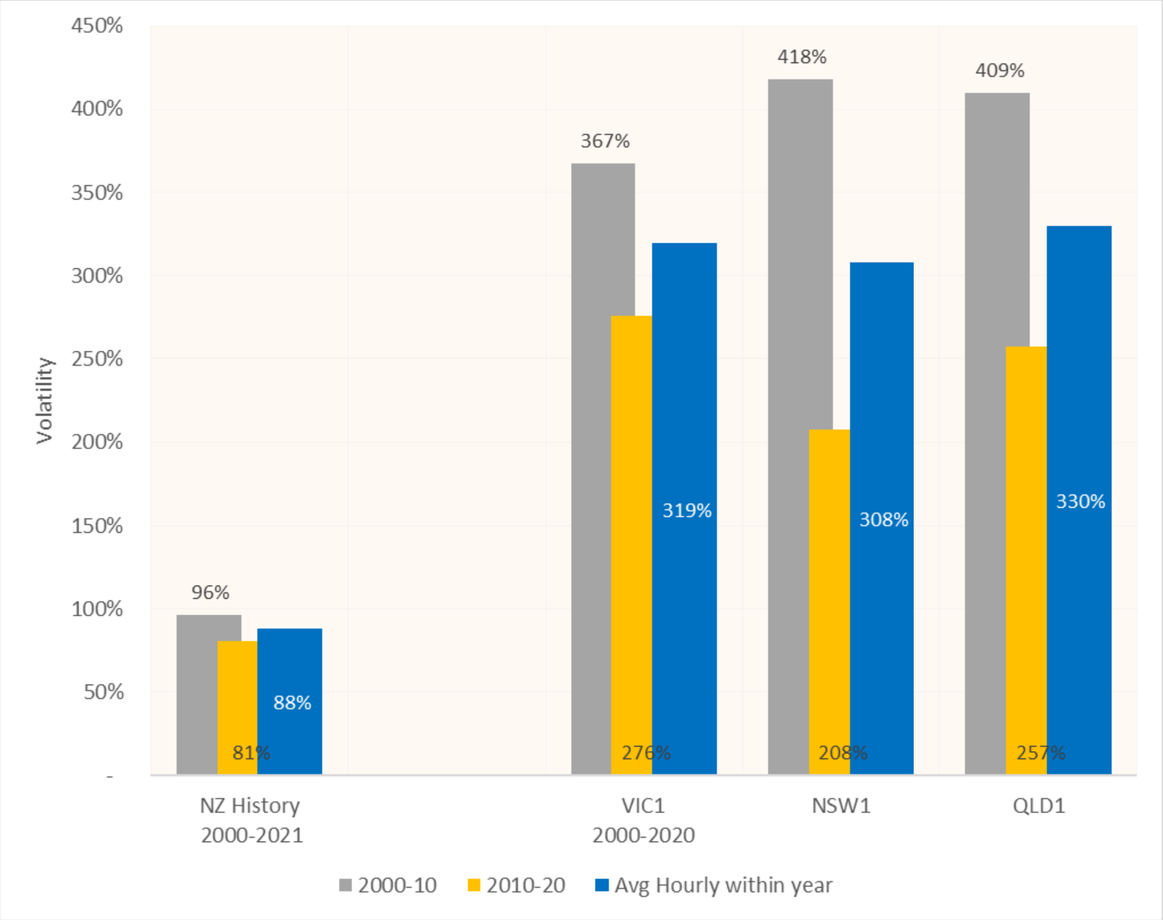
Notes

- All the measures are calculated using a consistent methodology:
  - All prices are converted to real 2020-dollar terms
  - The standard deviations of spot prices on each time frame are calculated.
  - These are converted to a volatility measure by dividing the standard deviation by the mean price over the full time period.
  - The 'full hourly volatility' measure is derived from the standard deviation over the full set (e.g. 52 * 21 years for NZ history)
  - The de-seasonalised volatility measures are derived by taking average of the standard deviations over all years for each week, month etc.
  - The chart also shows the simulated measures over 86 weather years for the system as it was in 2020, and in 2050 for the reference 100% renewable case and for each hydro offer sensitivities (high, mid and low).
  - The chart shows the model estimates for hourly prices from selected hourly runs.
    - These will be an underestimate of hourly volatility as the model assumes foresight within each week.

Hourly volatility this decade is less than the last decade in NZ and the NEM

We have derived the hourly price measures for the current and previous decade in NZ and in the NEM.

This demonstrates the changes in volatility over time. Contrary to our expectations it appears that NEM volatility in the last decade is lower than the previous decade.



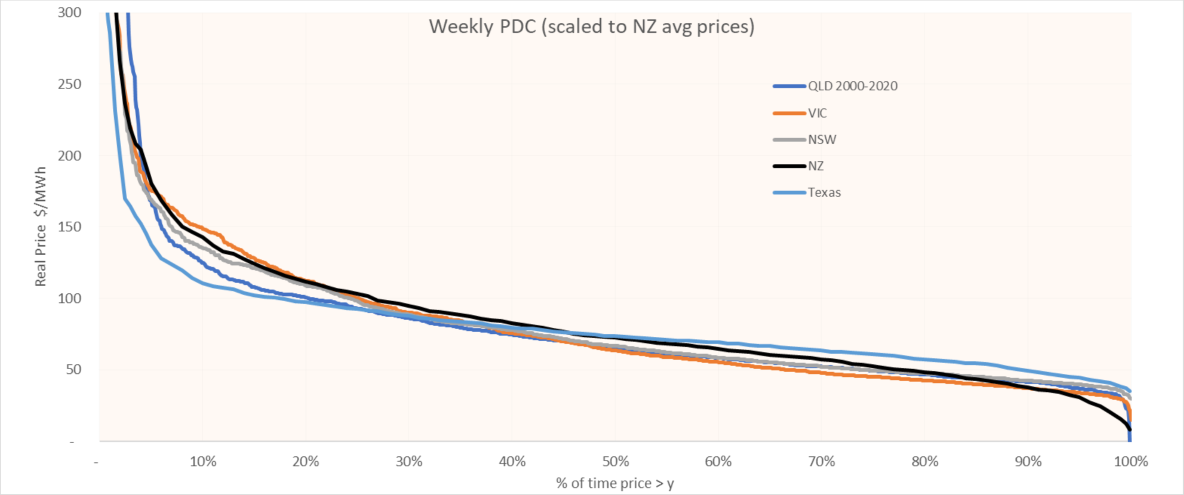
Notes:

- Anecdotally we would have expected volatility to have increased over time in the NEM as renewable penetration increased - causing more frequent swings in spot prices
- Curiously, the NEM data indicates that volatility at the hourly level was lower in the most recent decade compared to the previous decade
- Some differences are dramatic - e.g. NSW's volatility ratio is halved
- This data suggests that there has been quite substantial changes in the statistical measures of hourly volatility depending on the periods chosen.
  - This means we need to be careful about interpreting and comparing volatility measures on this time frame.
  - This is one reason why we have chosen to focus on weekly measures of volatility, for this study.

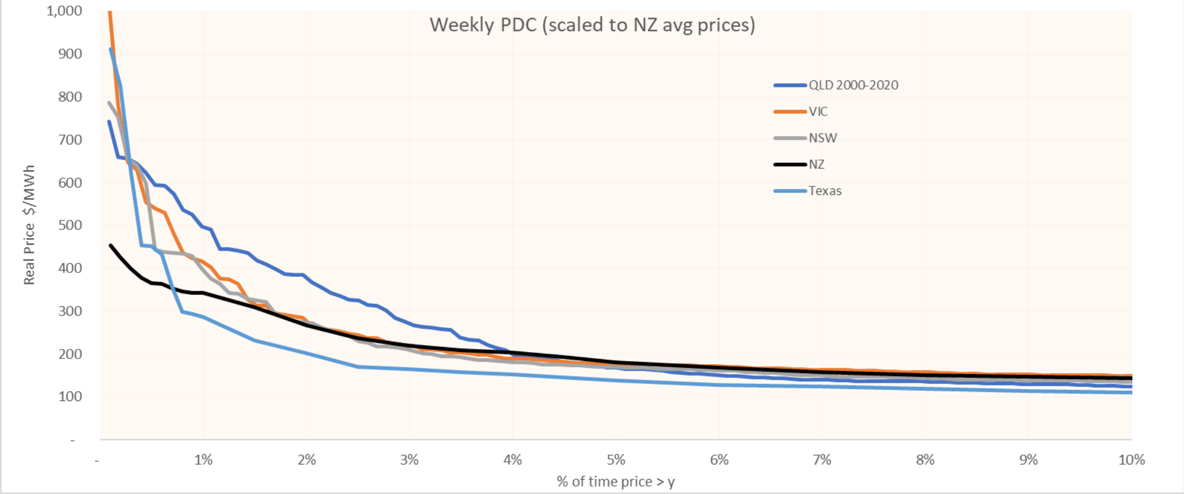
Weekly average price duration curves for the different markets are broadly similar once they are normalised to the same average.

NZ has a slightly greater slope in the LDC, but a much lower "top end" than the other energy markets which are thermal dominated and capacity constrained.

Bottom of PDC



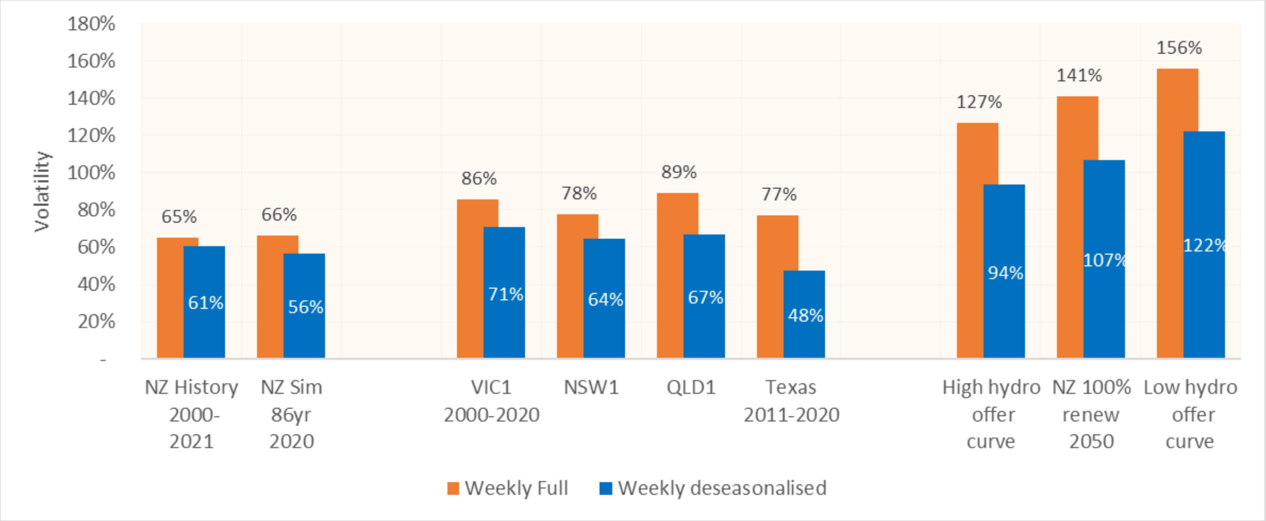
Top of PDC

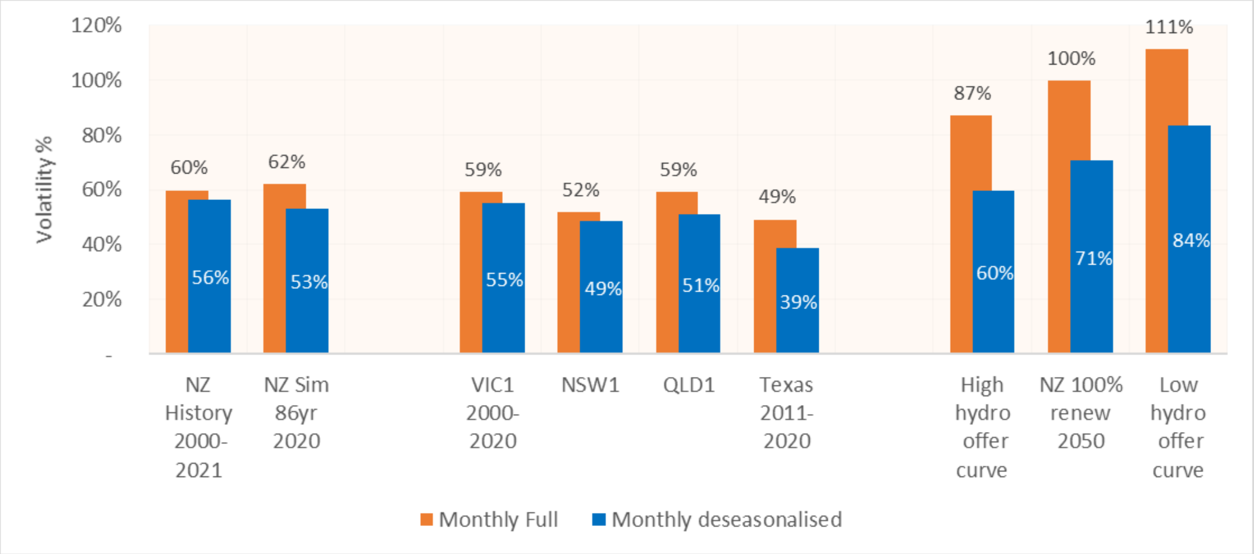


Notes:

- The charts show the duration curves for weekly average prices in real terms.
- These include all the available weeks data over approx. 20 years for NZ and the NEM, but only 10 years for Texas.
- The Texas prices are much lower, but have been scaled up to reflect the historical average price in NZ.

For comparisons across markets, we calculate measures of volatility which include and exclude seasonal variation

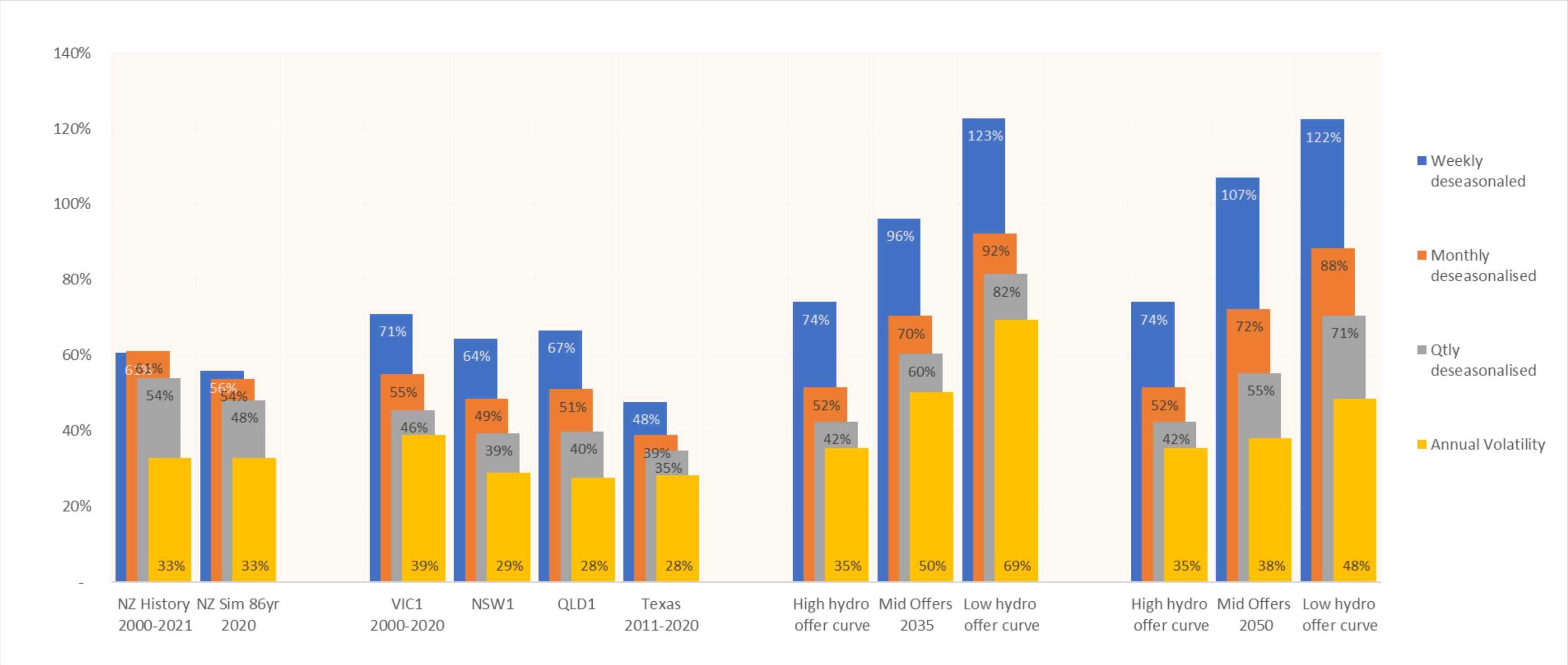




- **The 'full' volatility measure includes both the random (weather etc.) component and seasonal variation (winter summer etc.)**
- **The seasonal component of variation is fairly predictable and the 'average seasonal effect' is not strictly volatility**
- **The de-seasonalised measures remove the average seasonal component**
- **Arguably the weather-induced random component is likely to be of greatest concern to parties.**

Simulation focuses on weekly-to-annual average price volatility which is shown for the historical comparator markets and for the simulated results with a range of hydro offers

Weekly - annual volatility measures historical and modelled future - compared to historical and international benchmarks

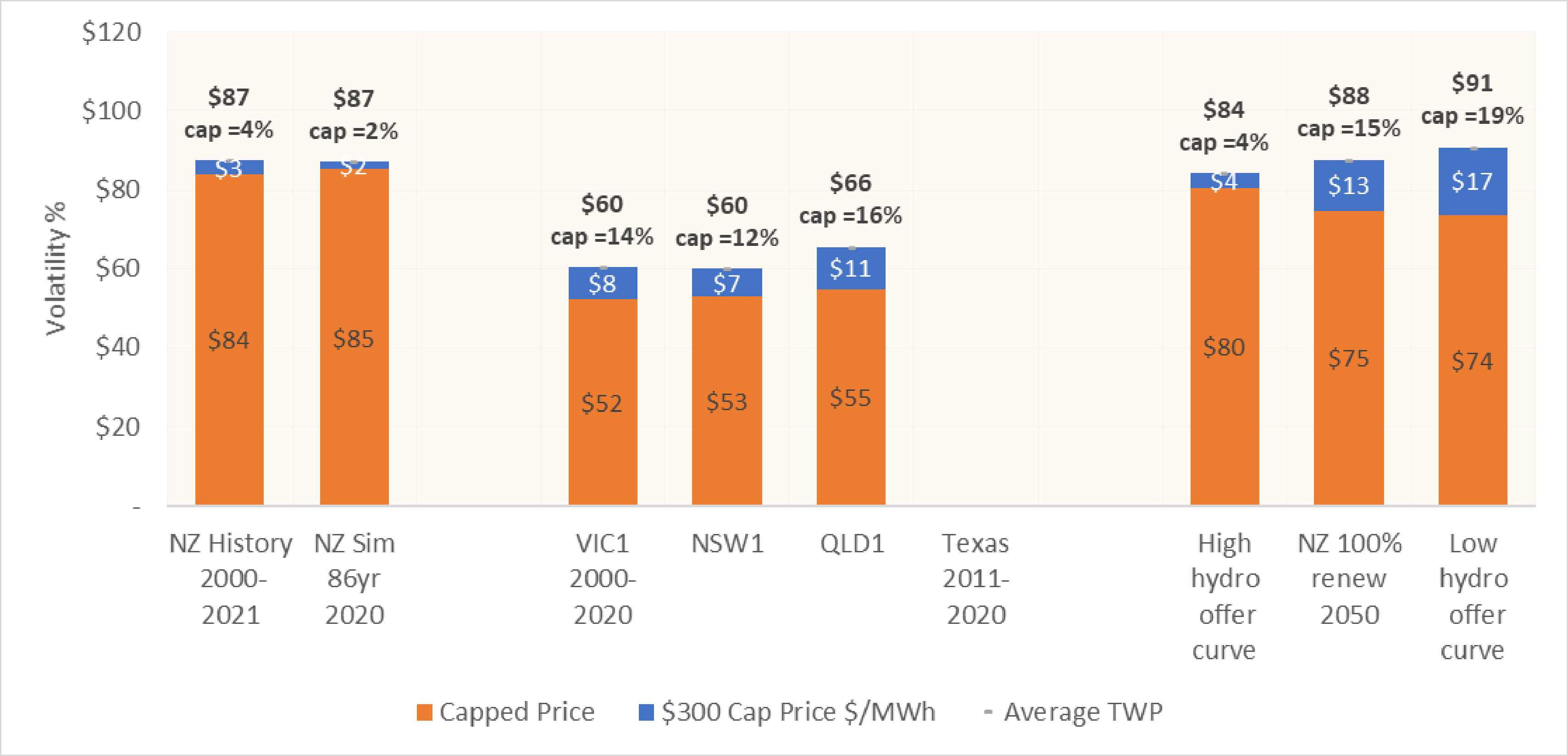


Notes:

- This chart shows the volatility measures for weekly through to annual time frames for the 3 hydro offer sensitivities in 2035 and 2050.
- NEM and Texas have had higher weekly volatility than NZ but similar or lower volatility for longer durations (monthly etc.)
- Simulated volatility results for NZ are higher than NZ history (especially at shorter end) and NEM and Texas
- NZ results are sensitive to hydro offer assumption - low offer case increases volatility across all spans of time (weekly, monthly and annual).

The $300/MWh cap price component of average prices is likely to increase from the historical 2-5% of the average price to around 15%, similar to NEM historical levels

The NZ market will become more capacity constrained as we move to 100% renewable. The component of average prices relating to spot prices above $300/MWh will rise significantly.



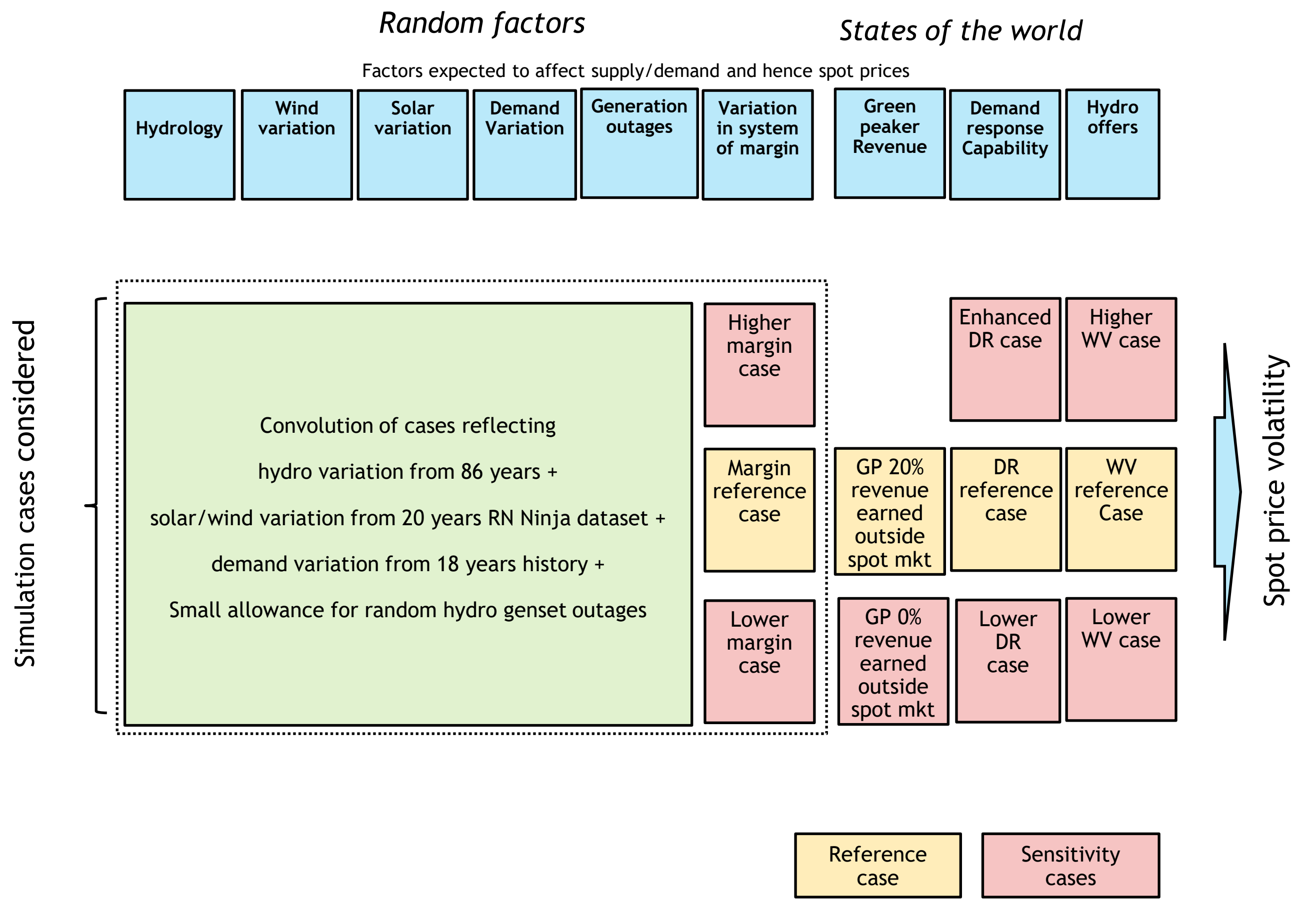
Notes:

- It is possible to decompose time weighted average prices into 2 components:
  - An average price capped at a maximum of $300/MWh, and
  - A “cap” component which is the contribution of spot prices above $300/MWh.
- The cap component can be thought of as an insurance product as it represents the risk of prices above $300/MWh.
  - This has been traditionally hedged in the capacity constrained Australian market.
  - This is used by retailers to cover the risk of extreme prices, and also provides a firm revenue for suppliers of peaking or reserve plant.
  - Vertically integrated companies often include peaking plant in their portfolio to cover such risks, either by ownership or by contract.
- By 2050 the NZ market is likely to become more capacity constrained (during the winter when wind is low in particular).
  - The insurance component in the NZ price is likely to increase significantly compared with history.

SENSITIVITY RESULTS

Summary of simulation cases analysed

In combination with 86 different weather years, we have modelled 7 different variations on the reference case to reflect different states of the world and different levels of system margin



Description of cases

- **Reference case**
  - This is the reference case with 70% of EV load shiftable by up to 5 hrs, and 30% of rooftop solar MW having batteries with 1-3 hr storage that can be scheduled in the wholesale market.
  - Hydro offers rise quickly from spill prices up to a relatively flat level then steeply to “green” peaker costs
- **Hydro offer cases in middle-zone**
  - **High**
    - Hydro offers rise quickly from spill prices then steadily up to “green” peaker costs
  - **Low**
    - Hydro offers rise slowly from “spill” prices exponentially to “green” peaker costs
- **Demand Response cases**
  - **Enhanced**
    - EV load shifting is 30% higher than the reference level and 0.4/0.6 GW of demand is fully price elastic over \$30-\$300/MWh.
  - **Lower**
    - EV load shifting and solar batteries are half, and price responsive demand is 70%, of the reference case levels.
- **System margin cases**
  - **High/low**
    - The mix of renewable and green peaker supply is approx. ±0.5GW higher/lower than new entry equilibrium levels
- **Green peaker revenue requirement**
  - High – require green peaker to achieve 100% fixed cost recovery from spot prices, rather than 80% as in the reference case.

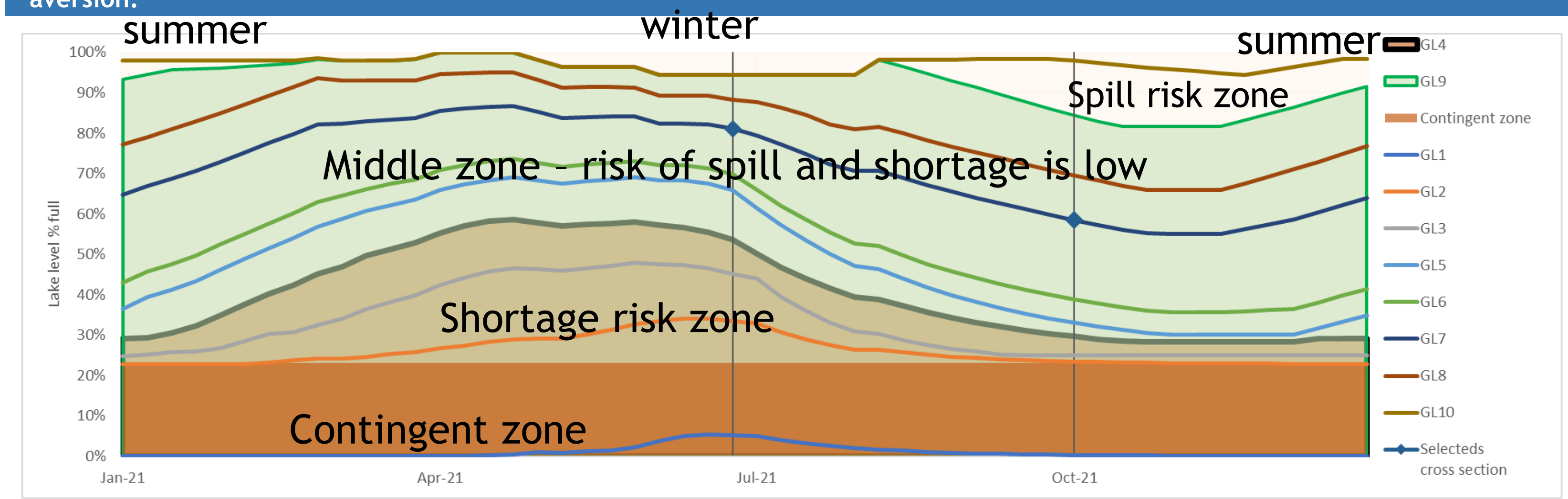
HYDRO OFFER CASES

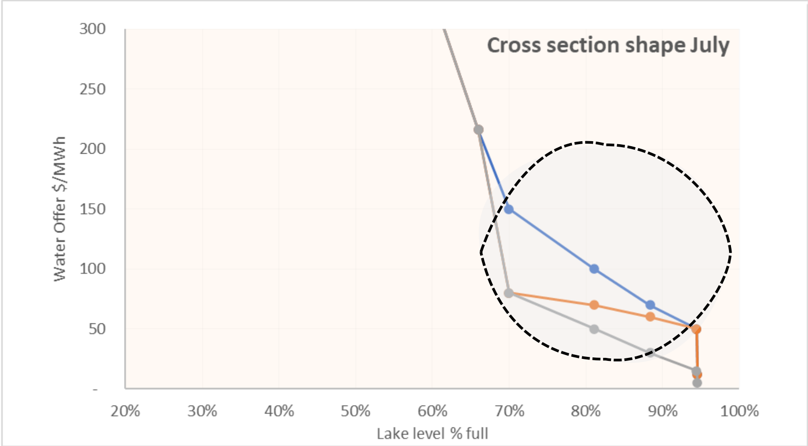
We represent hydro offer behaviour in terms of a set of equal hydro release offer contours and the prices on each contour reflect alternative offering assumptions.

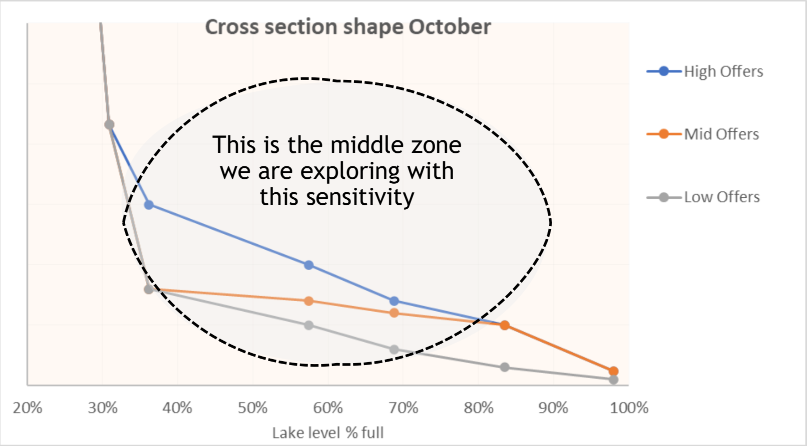
concept consulting

JC2

The shape of the contours are sculpted to reflect the risks of shortage and spill across the year and are a function of lake level. The prices on the contours rise from the cost of green peakers to shortage in the "risk" zone and fall towards the marginal cost of wind/solar/geothermal. The spill and green peaker contours can be adjusted to reflect different calculation methodologies and risk aversion.







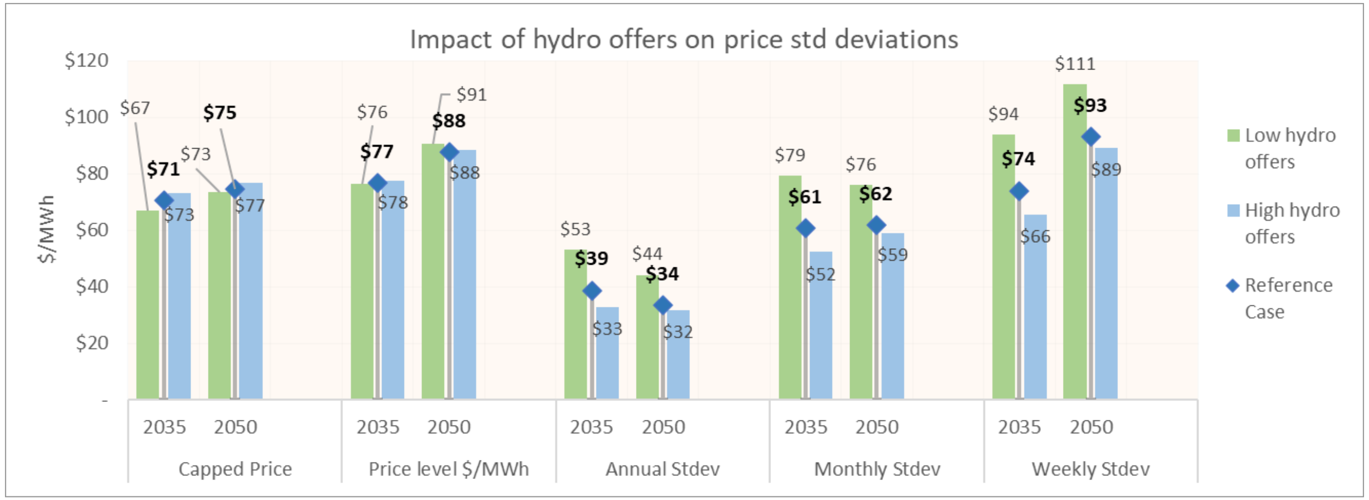
Three different sensitivities are explored for the shape of these offer curves.

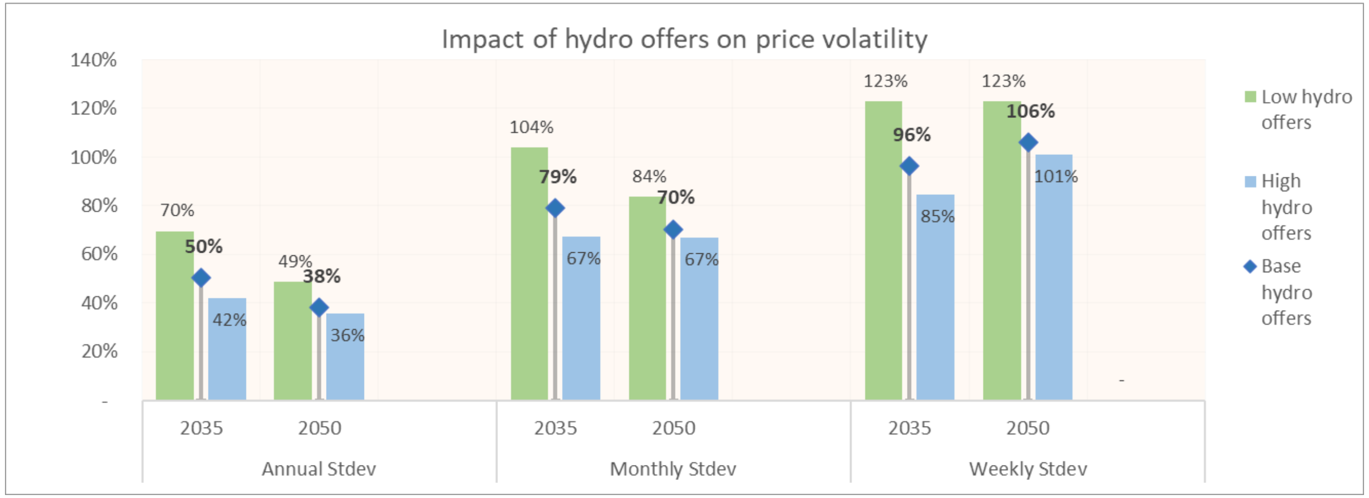
- **Offer prices on the green peaker and below contours reflect the cost of very flexible biogas or biodiesel supply and increase towards the cost of long-term demand reductions and or shortages.**
- **Offer prices in the spill zone reflect the potential variable cost or carbon cost saving that can be achieved when wind/solar or geothermal are dispatched off.**
- **In the absence of significant level of thermal plant backup, the shape of the offer curves in this zone do not have a material impact on total storage outcomes, however they can influence new entry which will have an impact on spill and shortages in future years.**
- **We have chosen 3 "cross section shape" sensitivities for the middle zone**
  - **High - Offers have a minimum of $12/MWh in the spill zone, and the rise to the green peaker cost.**
  - **Low - Offers are $5/MWh in the spill zone, then rise exponentially up to the green peaker cost.**
  - **Middle: - offers are competitive with wind O&M in the spill zone, then rise quickly to a relatively flat curve before rising steeply towards the green peaker cost.**

Note: for this study we have conservatively assumed that entering the contingent zone has an implicit penalty equivalent to around $700/MWh. It is possible that the contingent zone may be used more frequently and hence the implicit penalty might be low. This might change the results slightly in that investments may be delayed slightly and the contingent storage might be used more, but the resulting price volatility is likely to be similar.

Low hydro offers increases weather-driven weekly price volatility around 25% and high hydro offers reduces volatility by 5-10%

Changing the slope of the hydro offer has a noticeable impact on weather driven price volatility as shown below





Note: The Capped price level excludes the impact of prices above $300/MWh.

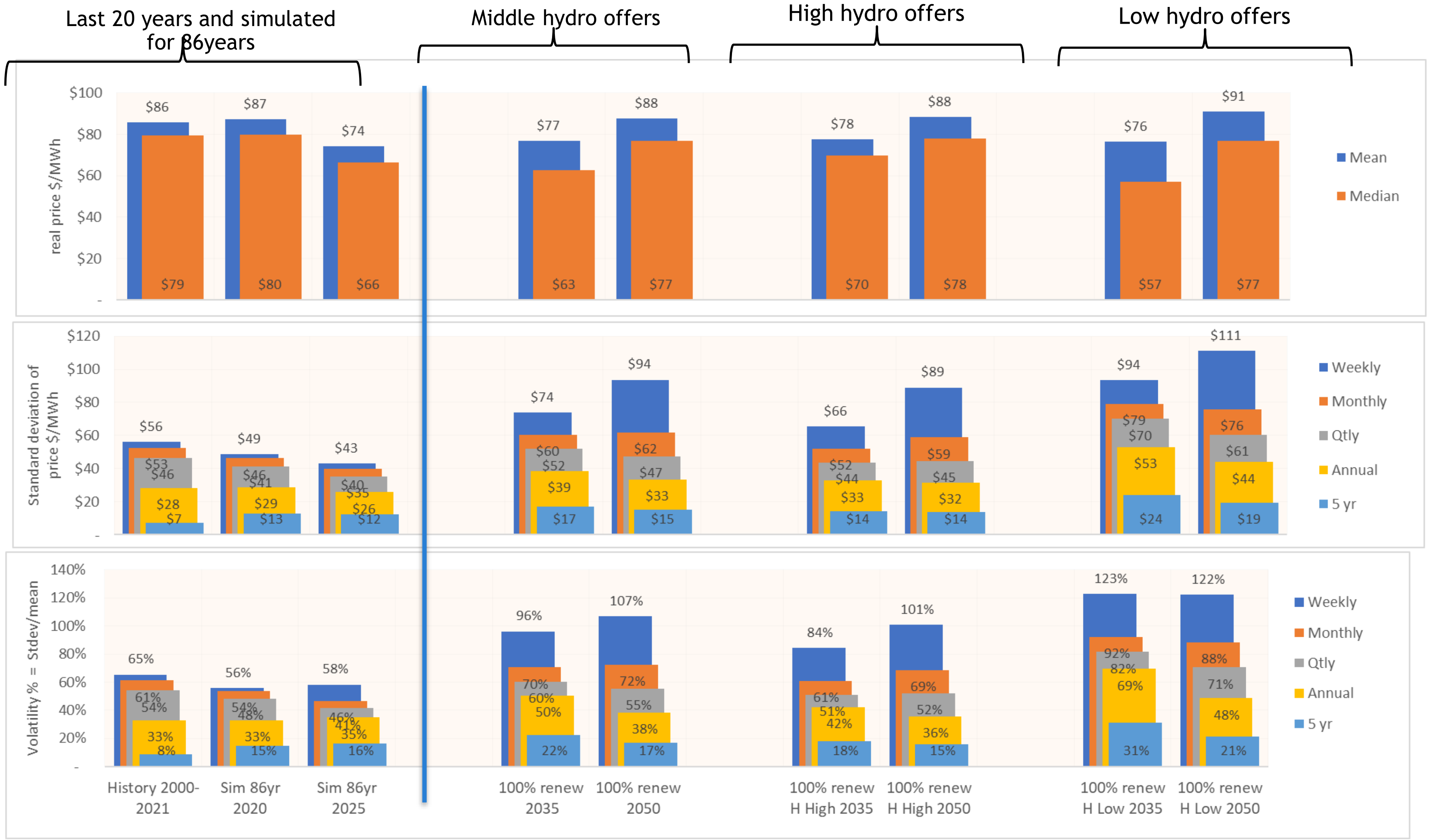
Commentary

- There is only modest variation in the price levels, as the modelling for this target year allows for small medium-term adjustments in new entry in response the altered pattern of prices in each sensitivity.
  - The pattern of prices impacts on the capture rates for wind and solar and this will impact the level and mix of new entry to some degree.
  - This second order impact is more pronounced in 2050 when the system has a higher level of intermittent supply.
- The annual standard deviation impact of hydro offers is greater in 2035 than 2050. Hydro variations are proportionally greater than other renewable supply in 2035.
  - In 2050 the impact of capacity issues with greater intermittent supply start to become more important than hydro.
- The biggest impact is from low hydro offers.
  - Low hydro offers increase weekly price volatility by around 27-17%
  - Low hydro offers increase monthly price volatility by around 23-14%
  - Low hydro offers increase annual price volatility by around 20-11%
- High hydro offers reduce volatility on all time periods,
  - but to a much lower degree.

Overall measures of volatility on annual, quarterly and monthly time frames

concept consulting JC2

Variation in the simulated hydro offer behaviour has a material plus or minus 10-20% on the weather driven volatility measures



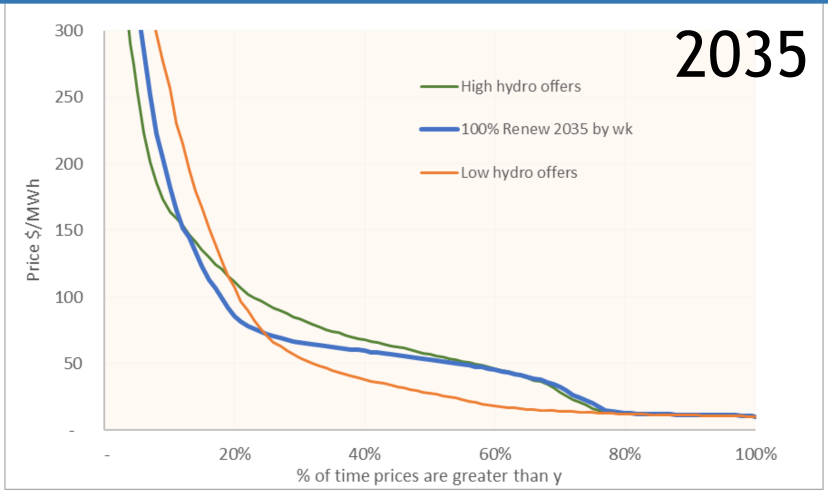
Commentary

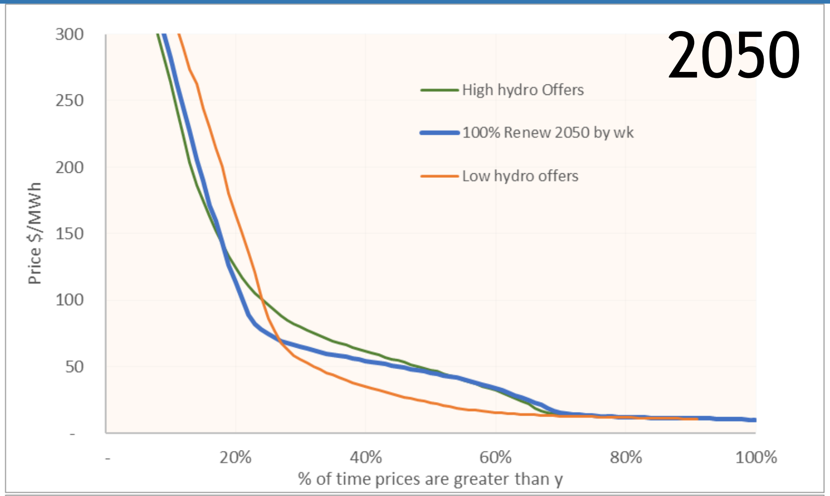
- These charts show the same results but also include some additional time frames and enable results to be compared with historical and simulated 2020 results.
- Note that the impact of low hydro releases offers on annual volatility is greater in 2035 than in 2050 when wind/solar volatility issues become more significant as the percentage of intermittent supply increases.

Weekly PDCs - with 100% renewables reference case and with high and low hydro offers

The shape of the weekly PDCs alter very significantly with low hydro offer curves in the middle zone. The impact of the higher curve is relatively modest.

Bottom of PDC





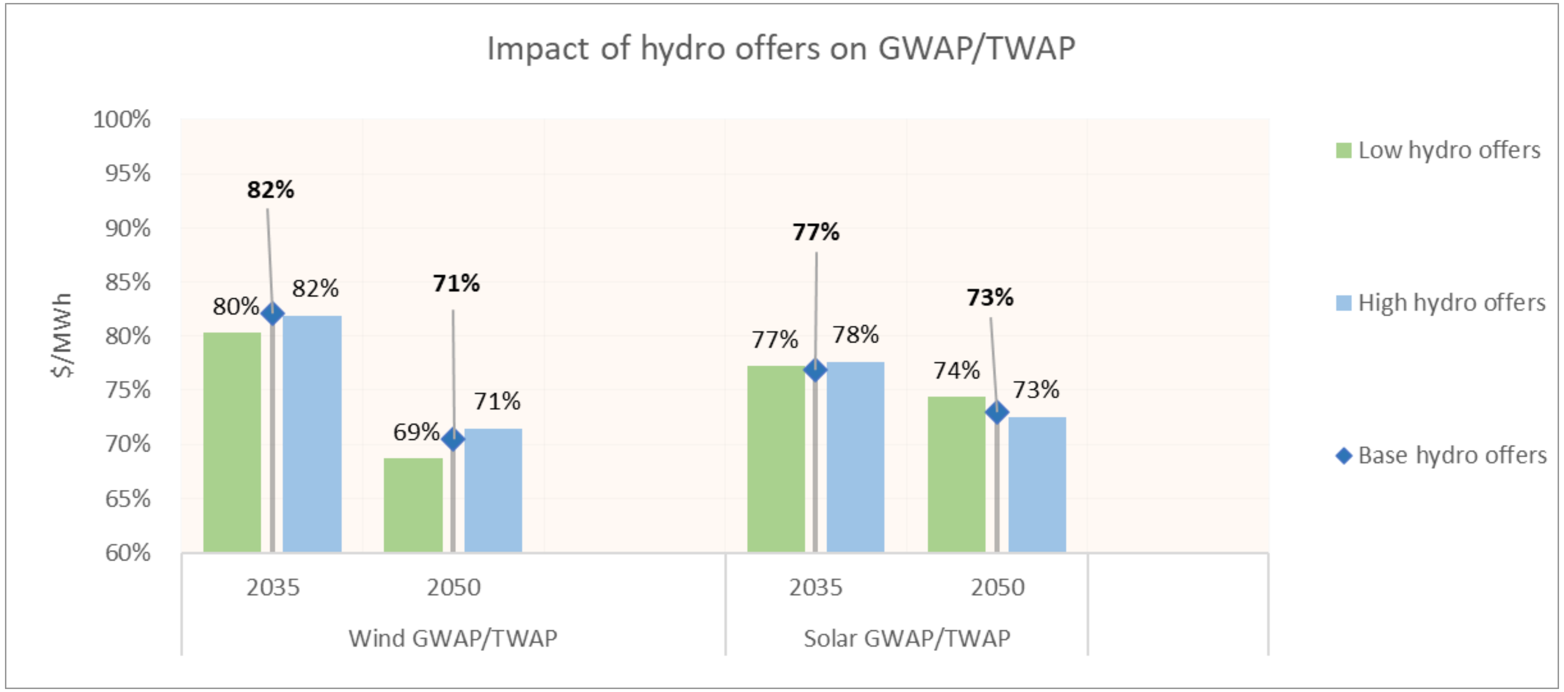
Top of PDC.

Additional Commentary

- **These charts show the resultant distributions of weekly average prices.**
- **The hydro release offer sensitivities show the first order impact on prices in the middle and low PDC (up to $80-90/MWh).**
- **The impact of prices above this are second order and result from changes in the mix and level of new investment in wind/solar.**
  - Lower hydro offers leads to slightly lower investment and hence higher levels of both capacity and dry year “events” and these feed through into higher top end price volatility.
  - Higher and middle offers lead to more investment and lower risks.

GWAP/TWAP factors fall for wind and solar with low hydro offers (higher volatility) and rise for high hydro offers (lower volatility)

The impact of hydro offering sensitivities on GWAP /TWAP for wind and solar is relatively modest. Low hydro offers create more volatile prices and lower GWAP/TWAP factors.



Commentary

- The impact in 2035 is modest as capacity shortfalls are less of an issue in 2035 compared with 2050.
- The impact of hydro offering curves is greater on wind than on solar.

Notes: The Wind GWAP/TWAP ratios are adjusted for spill so they can be compared more easily. This means that the GWAP is expressed in terms of the potential generation before spill. The achieved GWAP/TWAP based on actual generation after spill will be higher if the wind generators offer at a non-zero price and are dispatched off when prices are lower.

The high and low offer sensitivities assume hydro competes to avoid spill and so the total spill is very similar in each case

100% renewable reference case

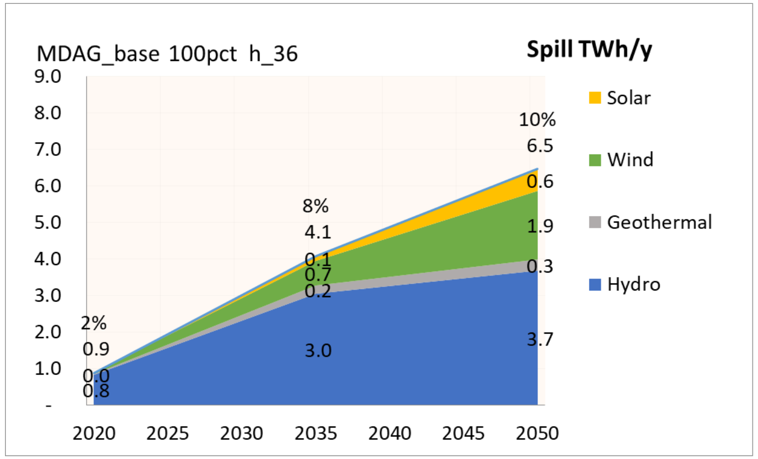
This has hydro offers competing aggressively with wind etc. so "spill" gets shared between hydro, geothermal, wind and solar.

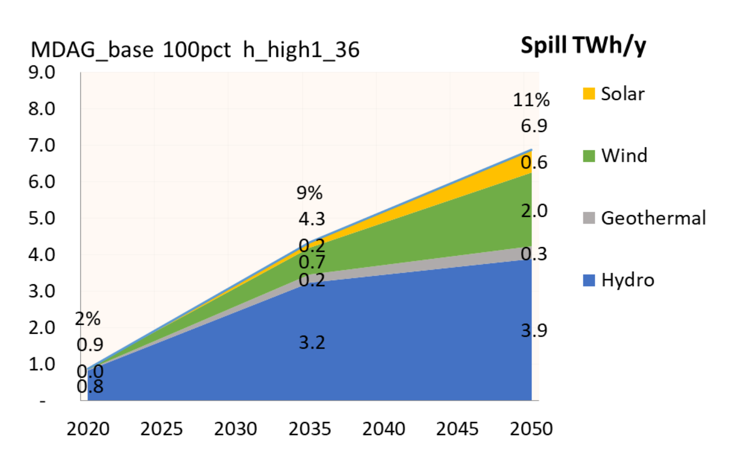
With high hydro offers the spill is similar, as it is assumed hydro still competes with other potential "spillers".

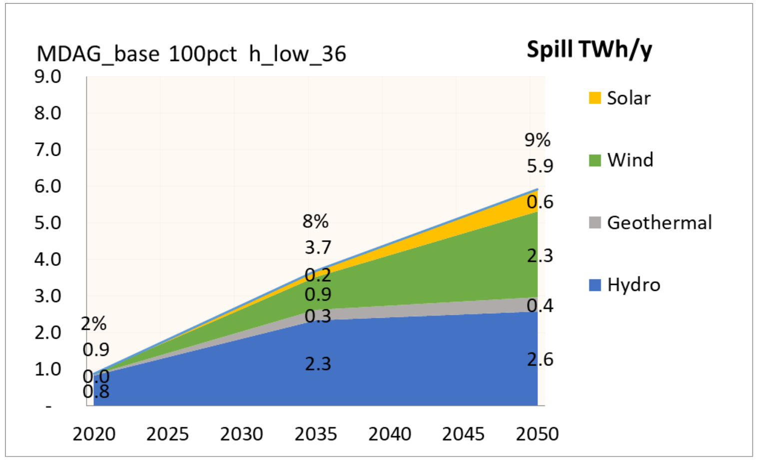
Demand response and shortage is similar given that hydro prices up to reflect the risk of shortage in the "hydro risk" zone

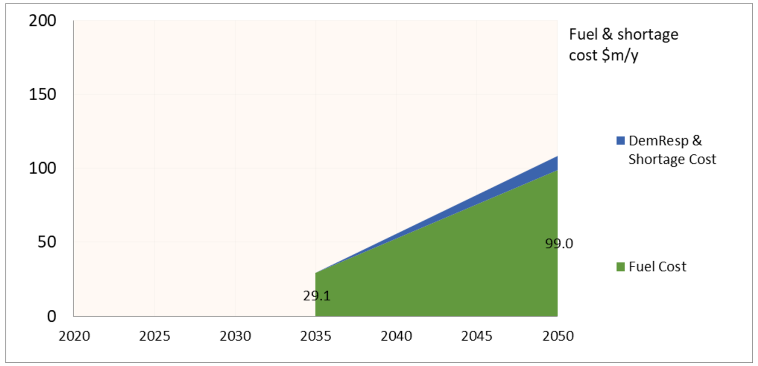
With low hydro offers in mid and the spill zone.

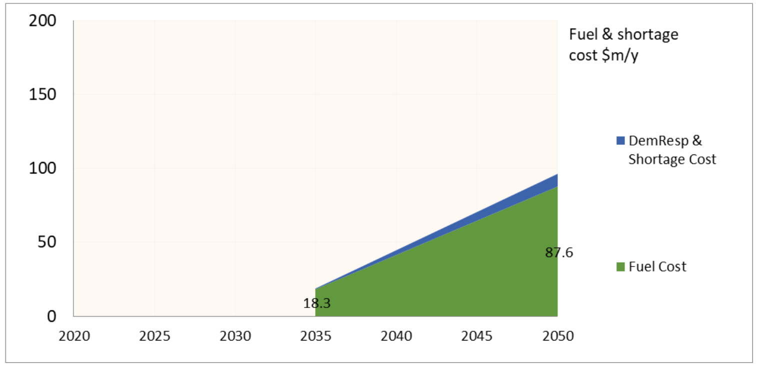
This is very similar to the reference case but has slightly more wind/solar spill and slightly less hydro spill. The overall spill is reduced somewhat.

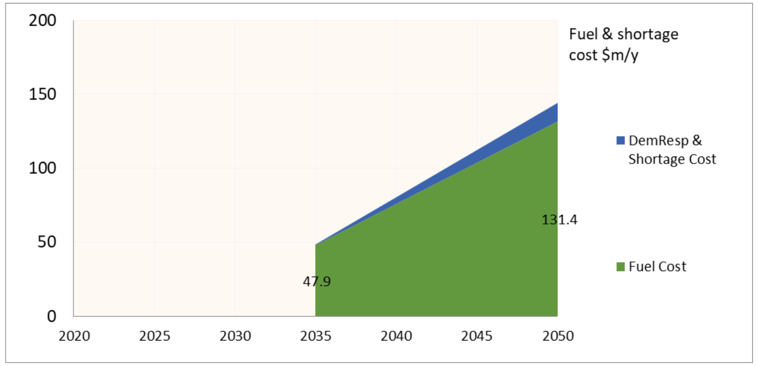






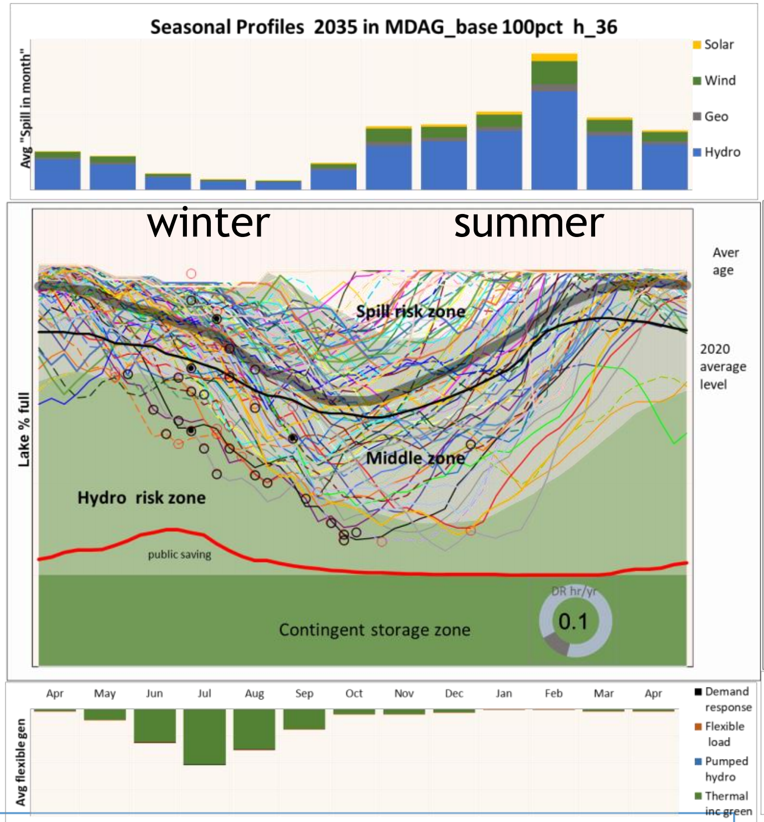






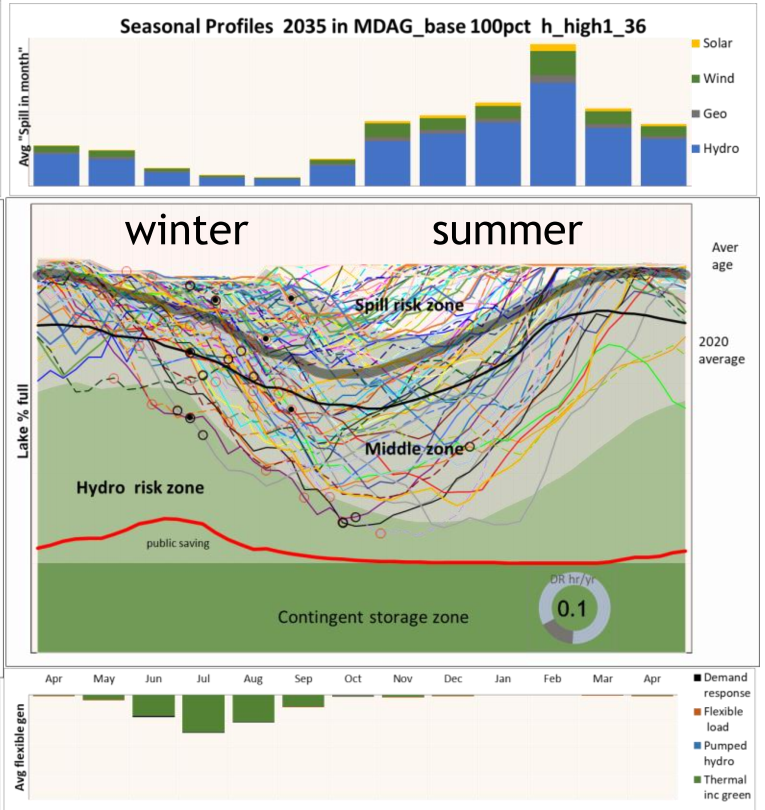
Lake level trajectories and use of green peakers is affected but mainly as a second order effect from changed new entry mix arising from different pattern of prices

Middle Hydro Release Offer Case



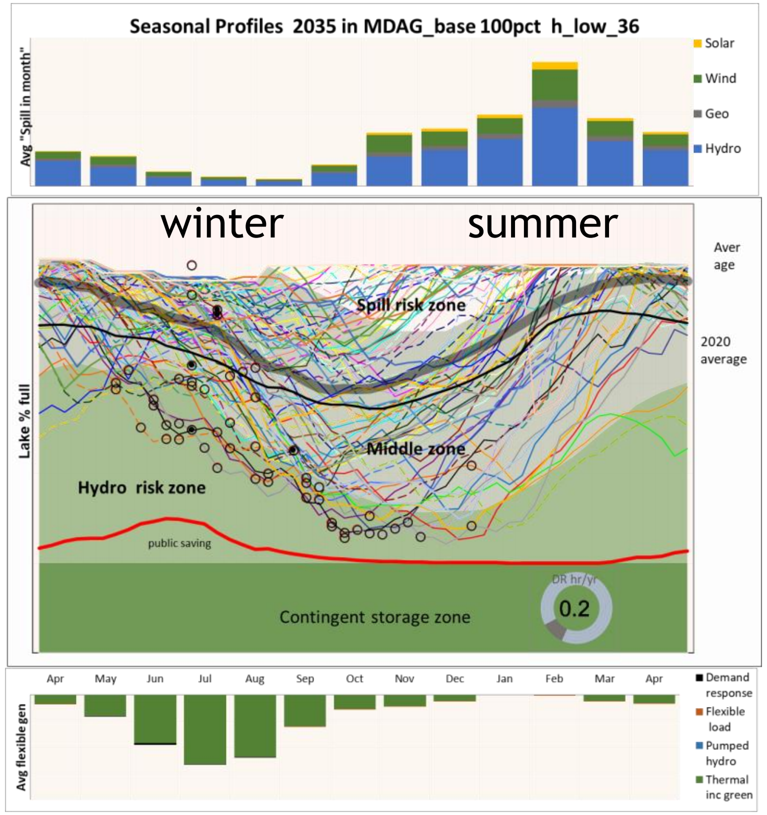
The middle hydro offer case is the same as our original reference case.

High Hydro Release Offer Case



The high hydro offer case has slightly higher levels of new investment in wind and solar as their capture rates are higher with lower price volatility.

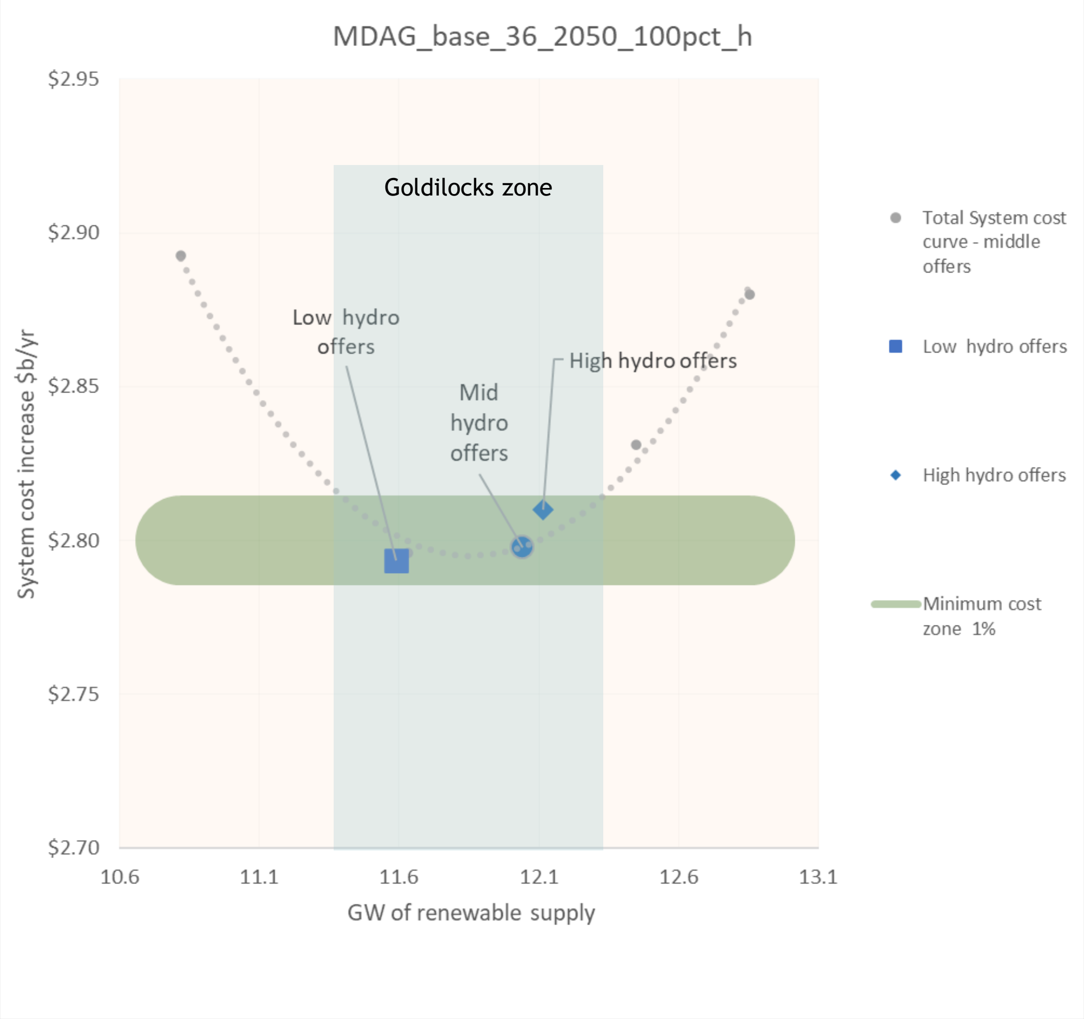
Low Hydro Release Offer Case



The low hydro offer case has slightly lower levels of new investment in wind and solar as their capture rates have deteriorated with higher price volatility. The lower level of new investment results in lower trajectories over winter and greater use of green peakers.

Assessing investment efficiency from a national perspective?

This chart shows the impact of different levels of new renewable investment on system cost in 2050.

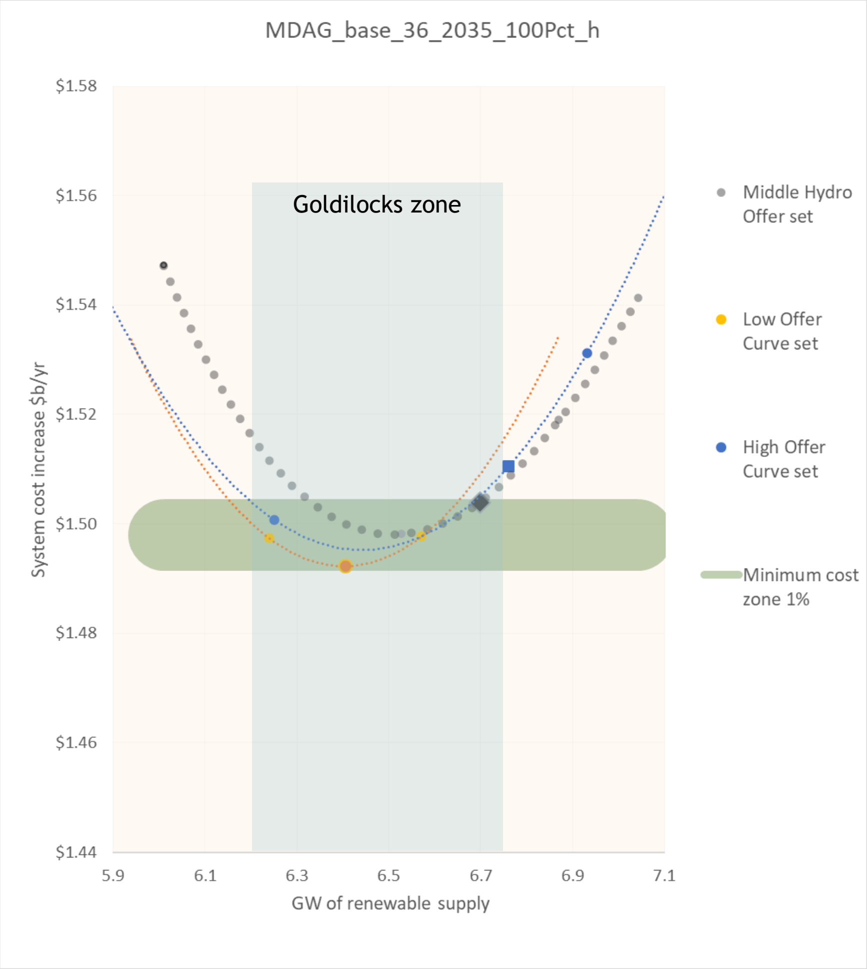


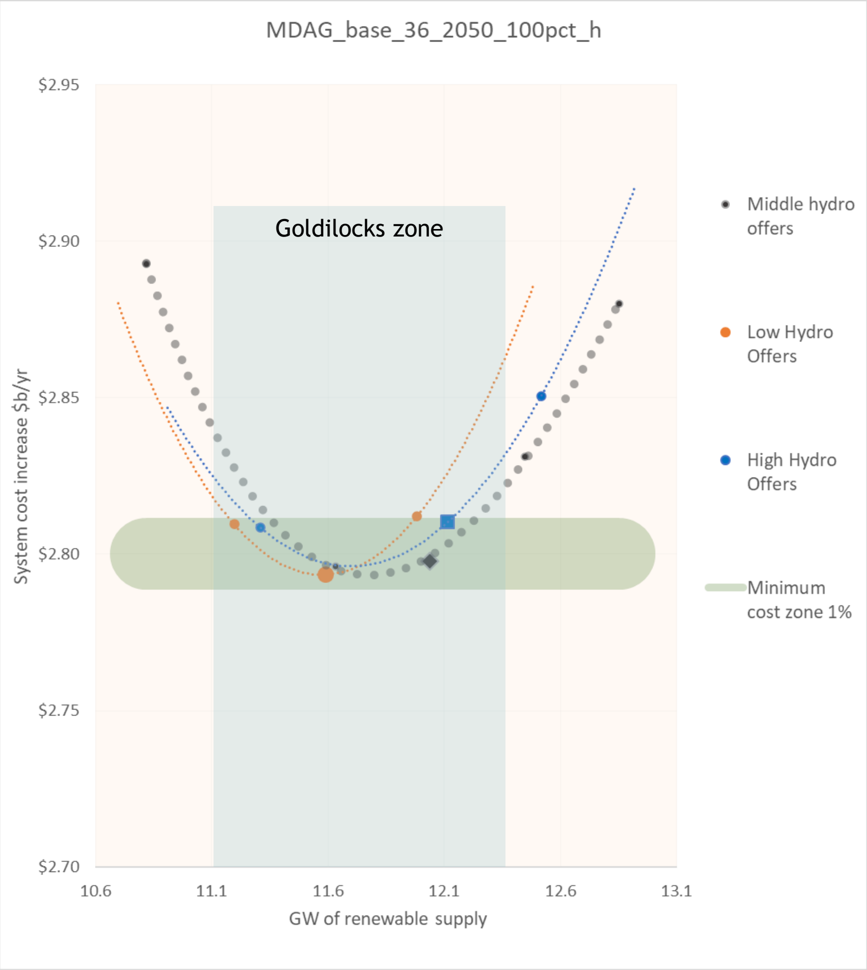
Notes:

- The chart shows the change in total system cost in 2050 as a function of the level of new investment in renewables.
  - The system cost is derived from the results of the whole system simulation averaged over the 86 weather years.
- The system cost includes:
  - the national cost of running the green peakers including a 15% additional cost to enable very flexible low-capacity factor operation, plus the costs of market demand response and any shortages or public conservation campaigns.
  - It also includes the annualised capital recovery and fixed operating costs for the incremental new investment in batteries, renewable plant etc. This is mainly a mix of renewable (mostly wind and solar).
- As additional renewables are built the cost of running the green peakers and market demand response declines,
  - but there is a rising fixed annual cost for the new plant (approximately linearly proportional to a weighted average of the mix of solar/wind investment).
- The sum of these is the total system cost which has a relative flat social minimum “goldilocks” zone which implies 11.4 to 12.3 GW of investment.
  - The position of this range reflects both the investment cost and the assumed variable cost of green peakers, demand response and shortage. These factors are uncertain and involve judgement.
- Given that the cost is relatively flat over this “Goldilocks” zone:
  - Risk aversion would suggest that there is likely to be a social preference for being on the right-hand side of the minimum range at this provides higher security and lower volatility than the left-hand edge.
  - Given all the uncertainties in the assumptions, any outcome within the 1% tolerance Goldilocks range can be considered socially “efficient”.

The hydro offer curve shape in the middle zone creates three slightly different national cost curves as a function of new supply but the minimums are well within modelling uncertainty.

Altering the shape of the hydro offer curves in the middle zone creates slightly different national cost curves but these are well within modelling accuracy levels.





Commentary

- The charts show the curves tracing out system national cost as a function of the level of renewable investment for the middle (grey), low hydro offer policies (yellow) and high offer policies (blue).
- These curves are very similar.
  - The low hydro offer curve is biased to the left (greater volatility and less investment) and the middle/high curves are biased to the right (more investment and less volatility).
- This suggests that national benefit outcomes are relatively insensitive to the hydro offer strategy in the "middle zone".
  - The 2035 results suggest that the middle hydro offer has slightly higher national cost outcomes.
  - But in 2050 the minimum cost for the middle curve is very similar to the minimum of the low offer curve, but offset to the right slightly.
  - Note that the minimum cost band is only 1% of total incremental system costs, well below the modelling uncertainty.

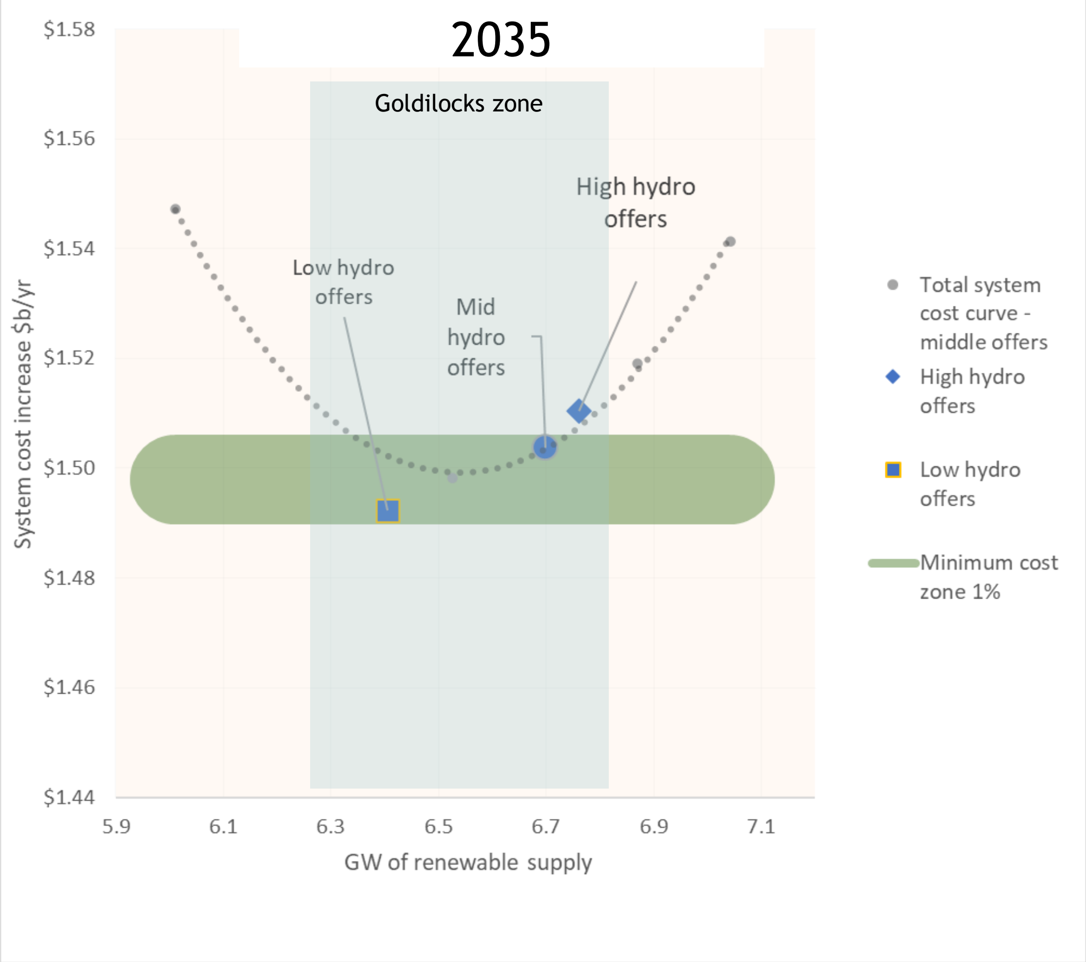
Simulating the market process of achieving revenue adequate levels for each new entry type results in national costs in the Goldilocks range, but are biased to left for low offers and to the right for the others.

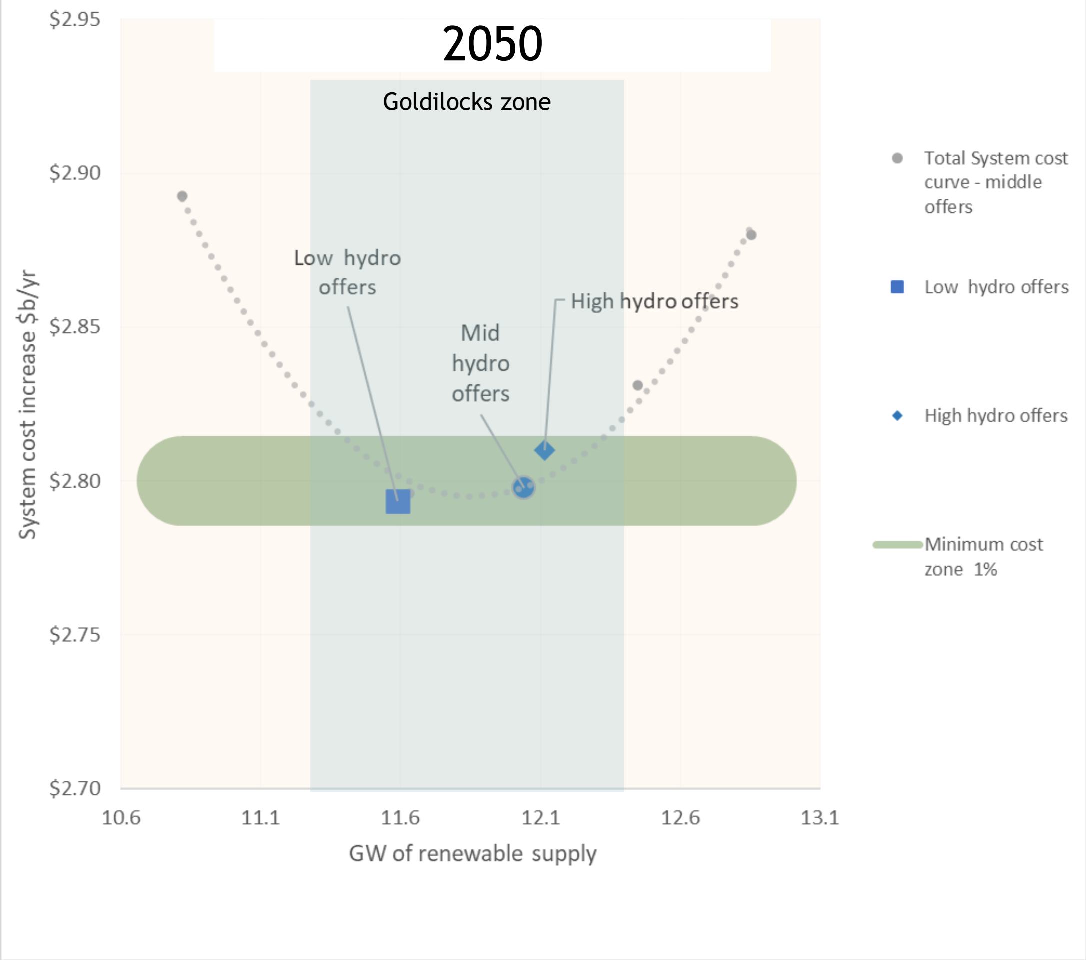
This chart shows the impact of different hydro offer strategies on the equilibrium level of investment and national system cost.

The low hydro offers provide a low system cost but are to the left of the Goldilocks zone, which has higher risk of shortages and high price volatility.

The mid offers have a similar cost but are to the right-hand end.

The high offer sensitivity has a slightly higher cost but is further to the right hand “safe” side of the Goldilocks zone.





DEMAND RESPONSE SENSITIVITY CASES

Description of Cases

Low Demand Response

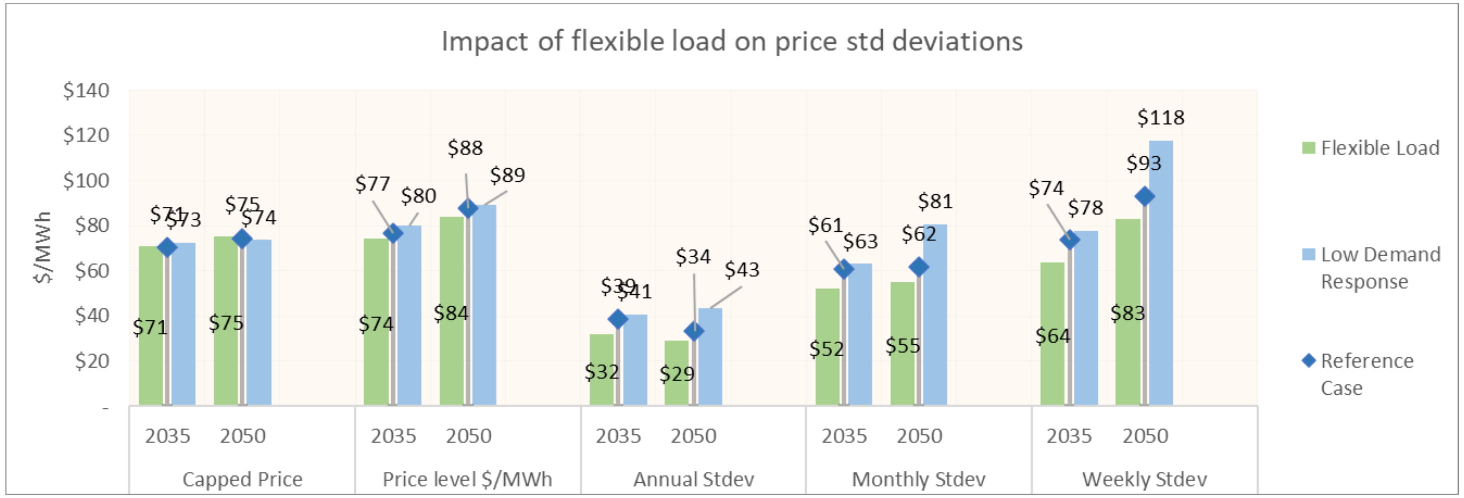
- **Low Demand Response Assumptions**
  - 50% of Reference smart EV load shifting
  - 50% of Reference PV distributed batteries
  - 70% of high price elastic demand response
  - No additional price elastic flexible demand

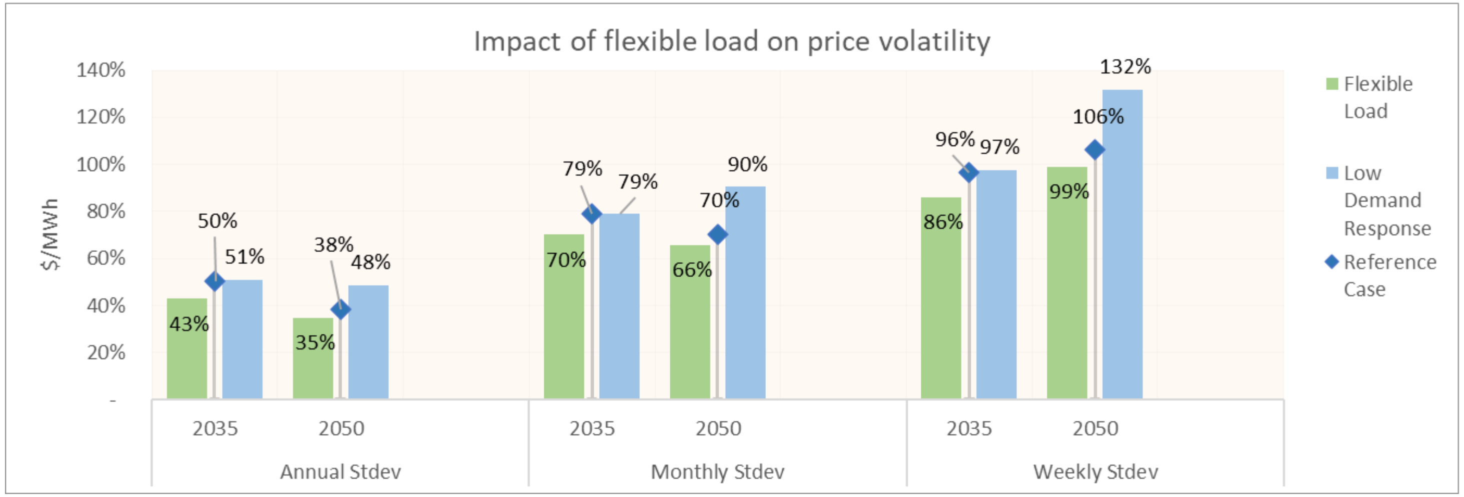
Enhanced Demand Response - Flexible load Case

- **Higher flexible load assumptions**
  - 130% of Reference smart EV load shifting
  - 100% of Reference PV distributed batteries
  - 100% of high price elastic demand response
  - Higher price elastic flexible demand
    - 400MW in 2035 and 600MW in 2050
    - Fully flexible demand triggered by prices ranging from $30 to $300/MWh.
    - This substitutes for underlying demand so total demand for generation is approximately the same.

Impacts of more or less demand response

Lower demand response lowers prices and increases price volatility modestly. Higher flexible load reduces price levels and volatility modestly.





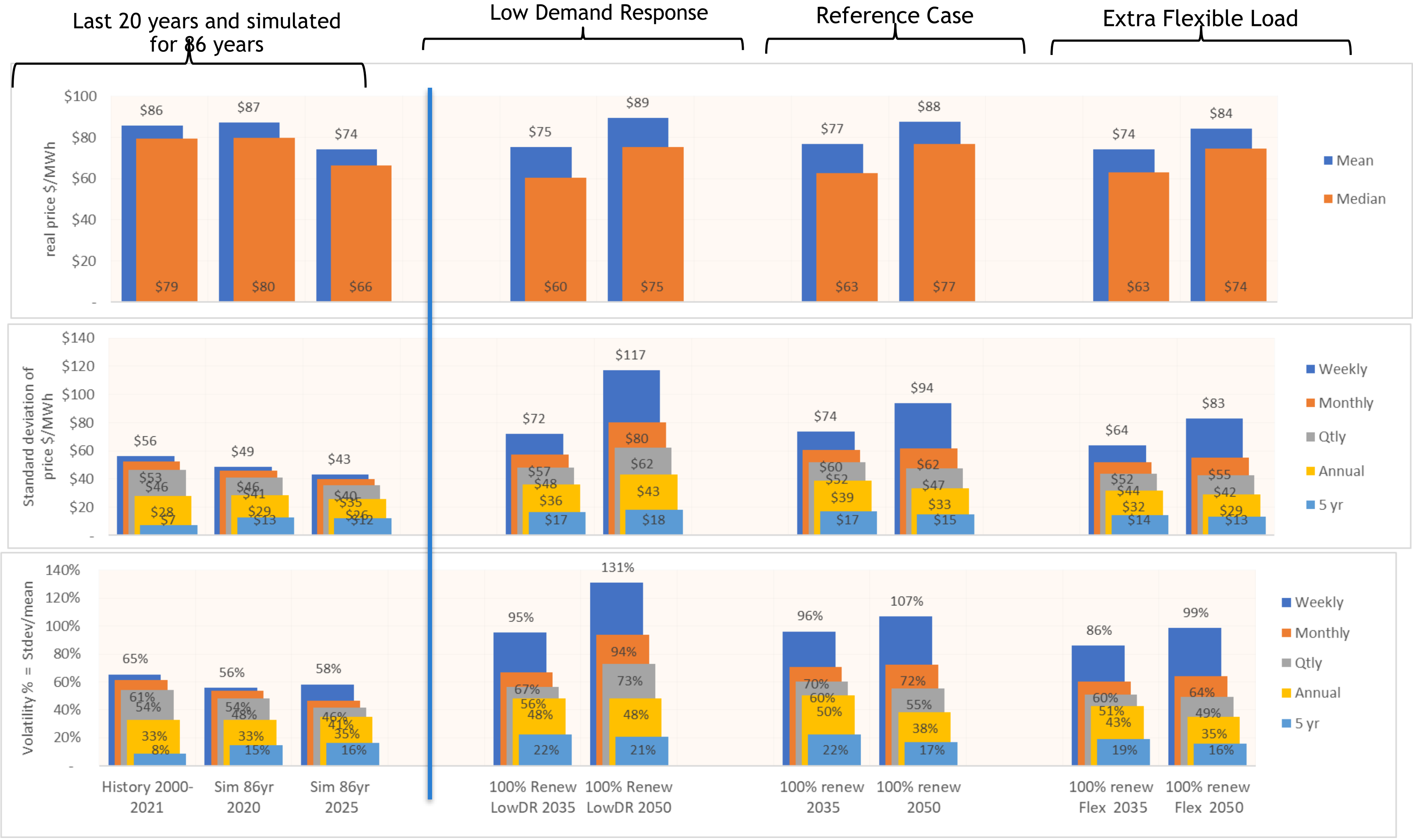
Note: The Capped price level excludes the impact of prices above $300/MWh.

Commentary

- There is only modest variation in the price levels, as the modelling for this target year allows for small medium-term adjustments in new entry in response to the altered pattern of prices in each sensitivity.
  - The pattern of prices can have an impact on the capture rates and dispatch levels for wind and solar and this will impact the level and mix of new entry to some degree.
  - This second order impact is more pronounced in 2050 when the system has a higher level of intermittent supply.
- The annual standard deviation impact of hydro offers is greater in 2035 than 2050. Hydro variations are proportionally greater than other renewable supply in 2035.
- In 2050 the impact of capacity issues with greater intermittent supply start to become more important than hydro.
- The impact of low demand response is relatively minor since any loss of demand load shifting is replaced with a mix of shorter and longer term batteries and an increase in green peakers.

Overall measures of volatility on annual, quarterly and monthly time frames

Variation in the simulated hydro offer behaviour has a material plus or minus 10-20% on the weather driven volatility measures



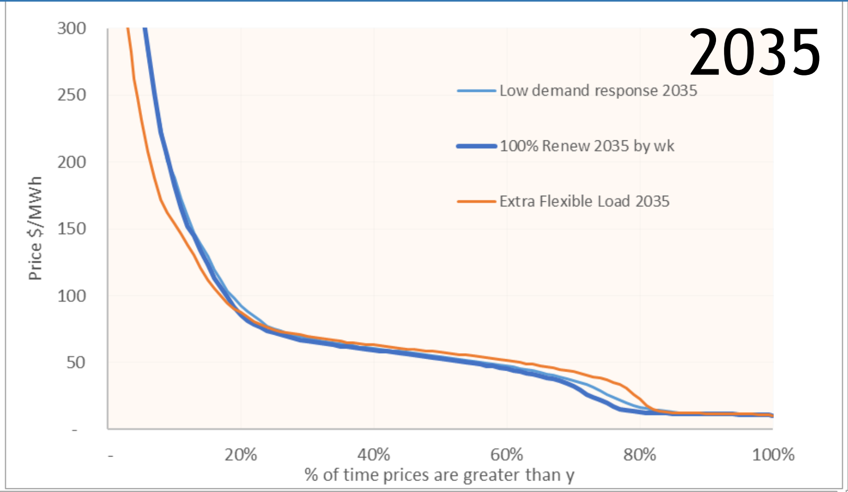
Commentary

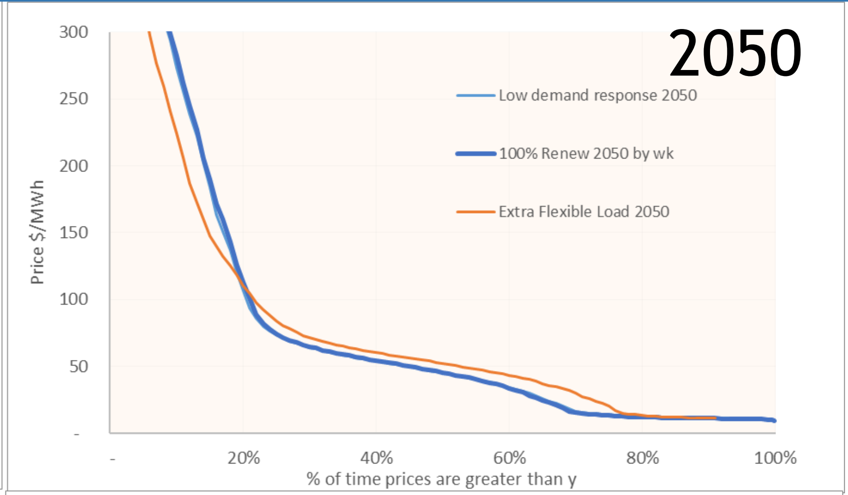
- These charts show the same results but also include some additional time frames and enable results to be compared with historical and simulated 2020 results.
- The level of prices is very similar in the low DR case in 2035.

Weekly PDCs - with 100% renewables reference case and with high and low demand response

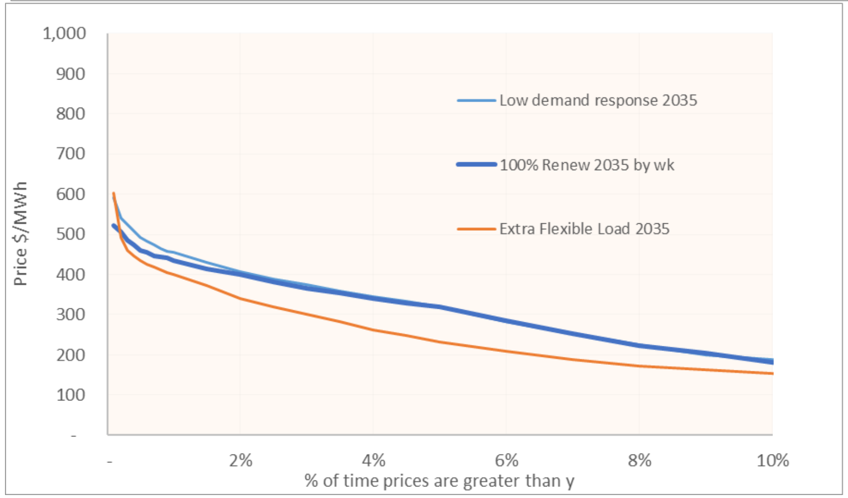
The shape of the weekly PDCs is very similar for the reference and low demand response cases, as the loss of within day demand response is compensated for by increased investment in batteries and green peakers. The flexible load case has a much larger impact since it responds in the lower price bands and replaces medium/longer term storage and reduces spill.

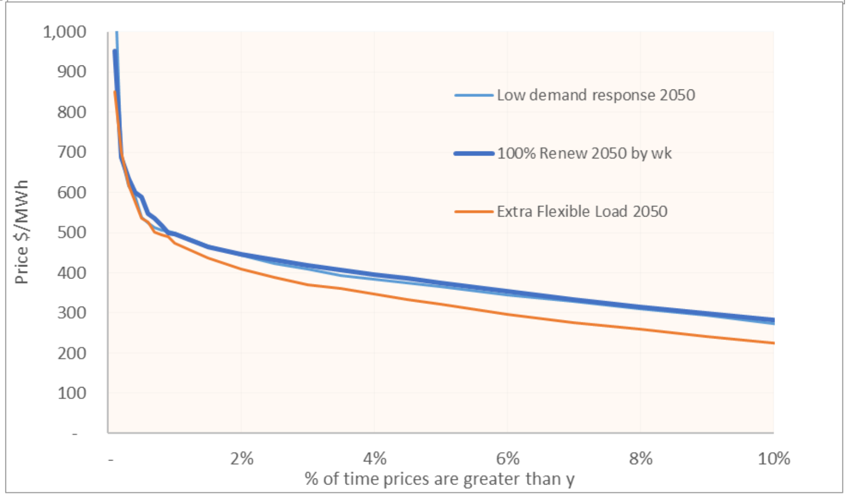
Bottom of PDC





Top of PDC.





Additional Commentary

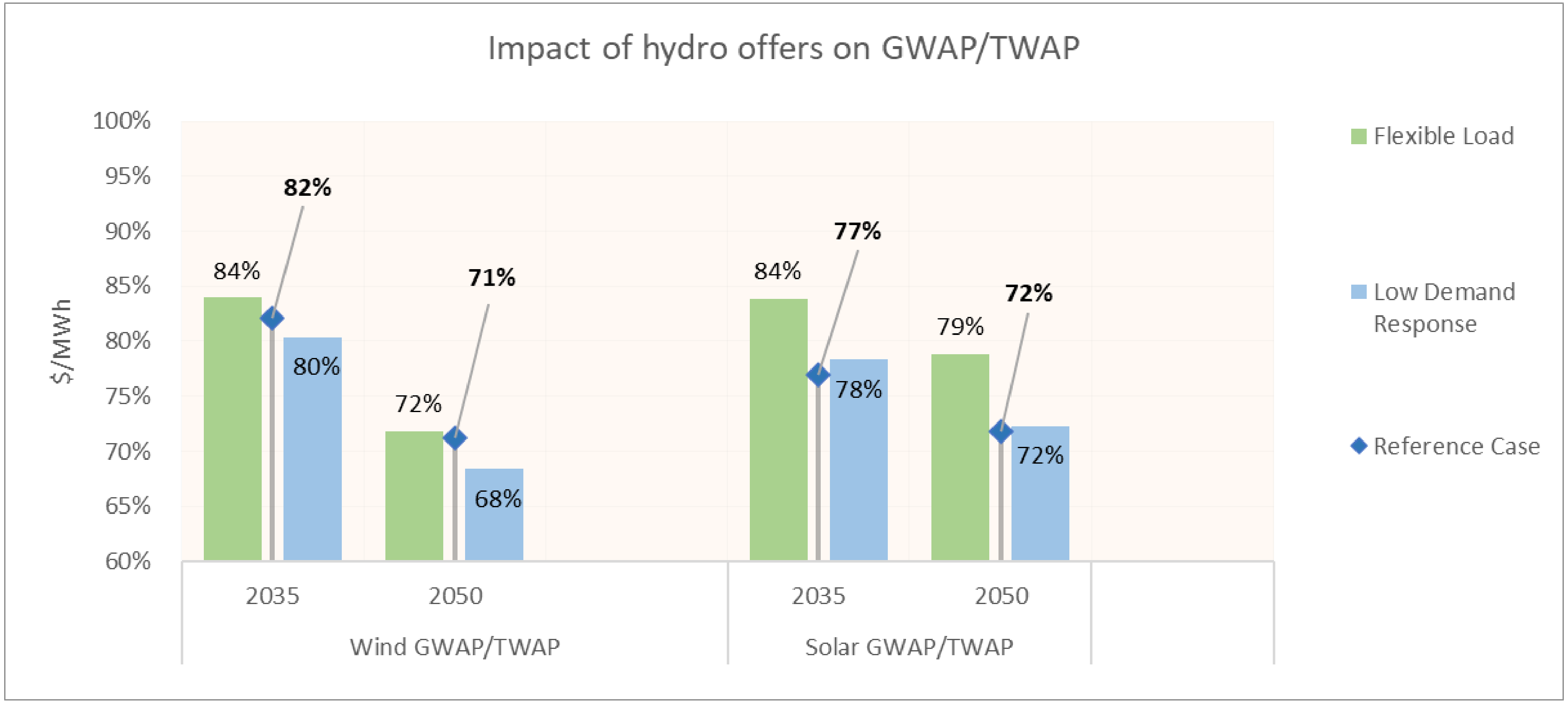
- **These charts show resultant distributions of weekly average prices.**
- **This shows that there is only a small impact of the low demand response case:**
  - This is expected since the modelling approach for periods within each week is simplified.
  - A loss of solar batteries or EV load shifting capability is compensated by building grid connected batteries of 5 to 12hr duration.
- **The impact on the weekly price duration curve of additional fully flexible price responsive demand is much greater.**
  - This is because such flexible load can effectively provide weekly, seasonal and dry year backup which has a much greater impact on weekly price volatility.

GWAP/TWAP factors fall for wind and solar with low hydro offers (higher volatility) and rise for high hydro offers (lower volatility)

The impact of high and low demand response on GWAP /TWAP for wind and solar is relatively modest.

Low demand response reduces GWAP/TWAPs and more lower price responsive flexible load increases GWAP/TWAP factors.

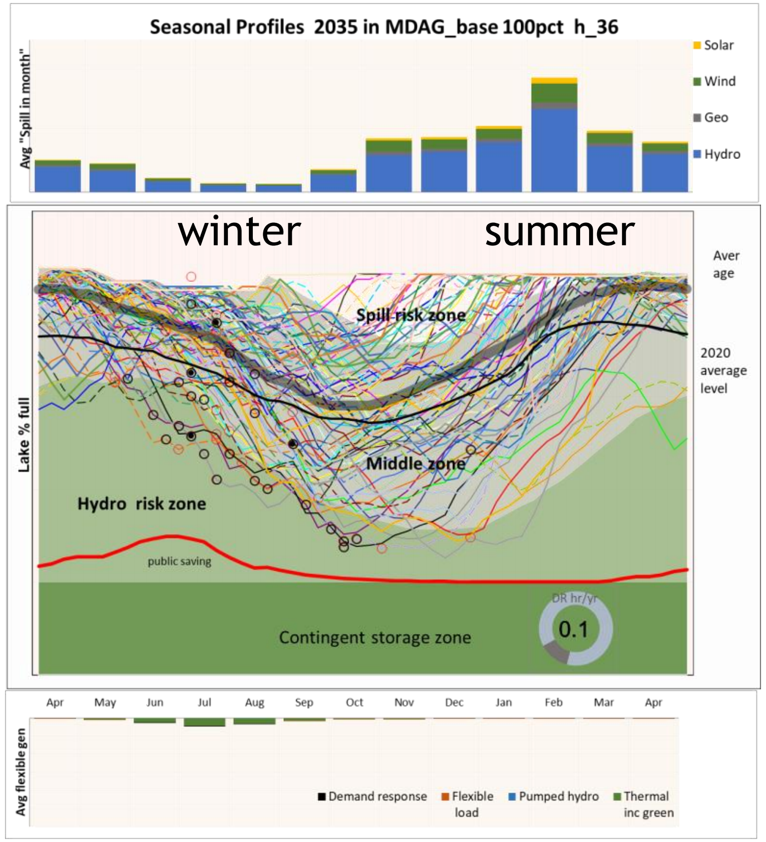
The effect is greater in 2050 due to greater frequency of capacity shortfalls.



Notes: The Wind GWAP/TWAP ratios are adjusted for spill so they can be compared more easily. This means that the GWAP is expressed in terms of the potential generation before spill. The achieved GWAP/TWAP based on actual generation after spill will be higher if the wind generators offer at a non-zero price and are dispatched off when prices are lower.

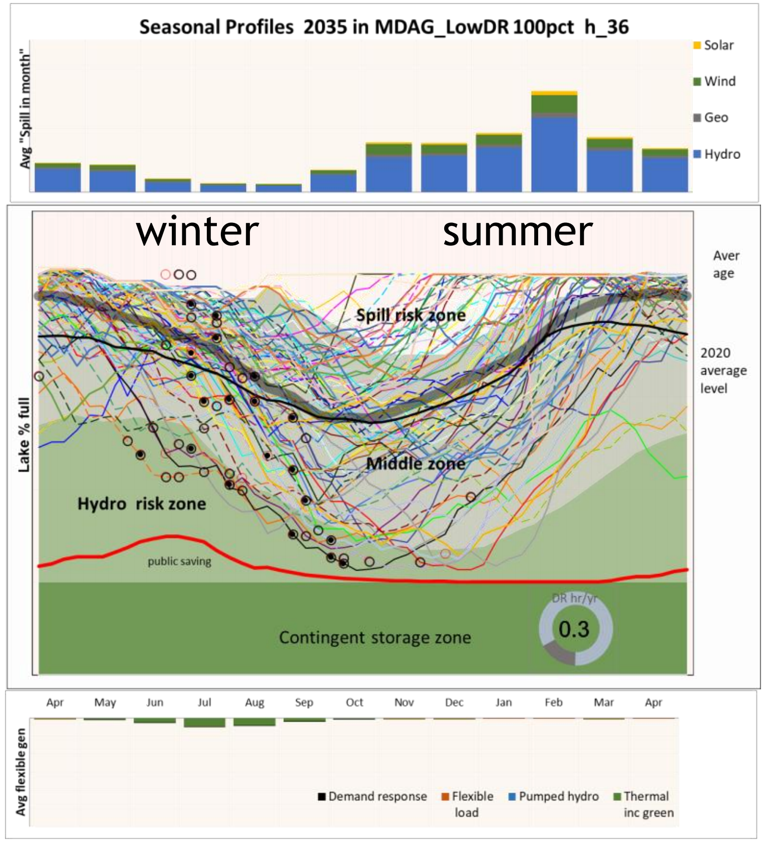
Lake level trajectories and use of green peakers is similar in the reference and low demand response cases in 2035

Reference Case



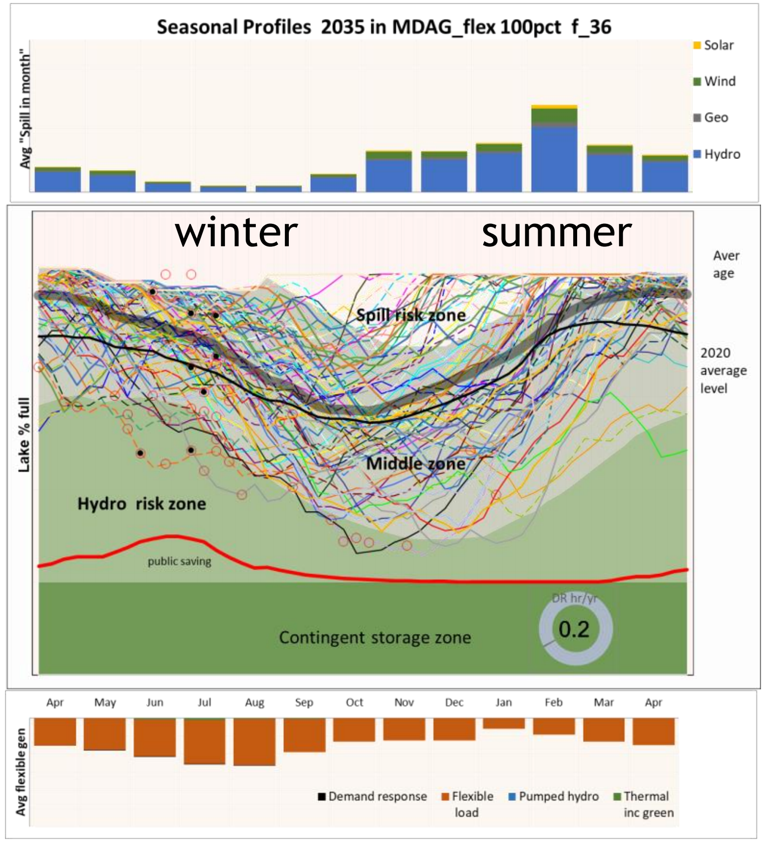
The middle hydro offer case is the same as our original reference case.

Low Demand Response Case



The low demand response case is very similar to the reference case but has a greater frequency of demand response and capacity constraints in 2035

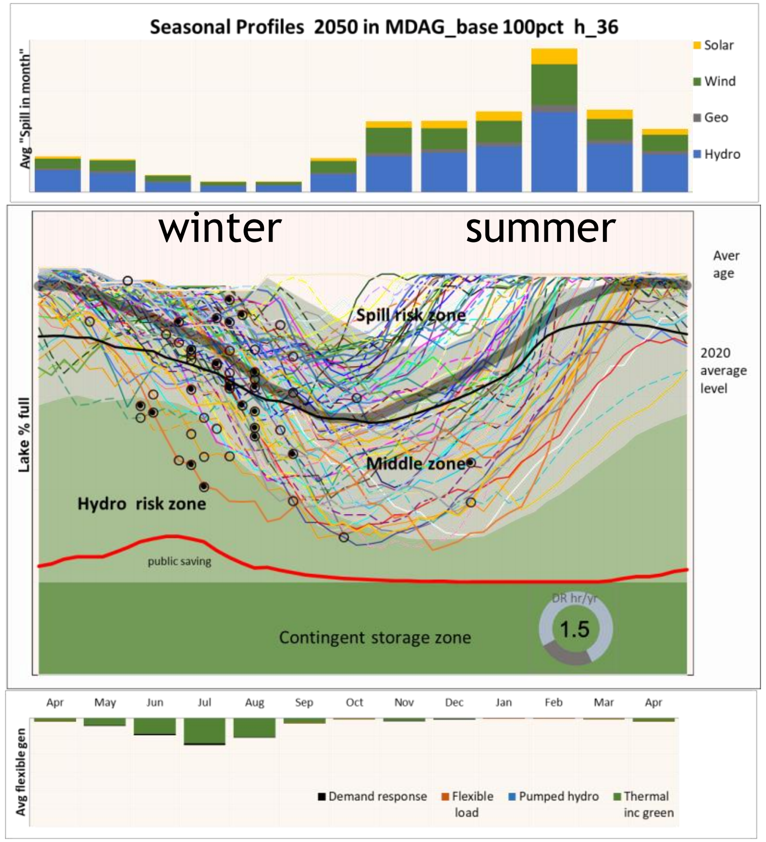
High Flexible load case



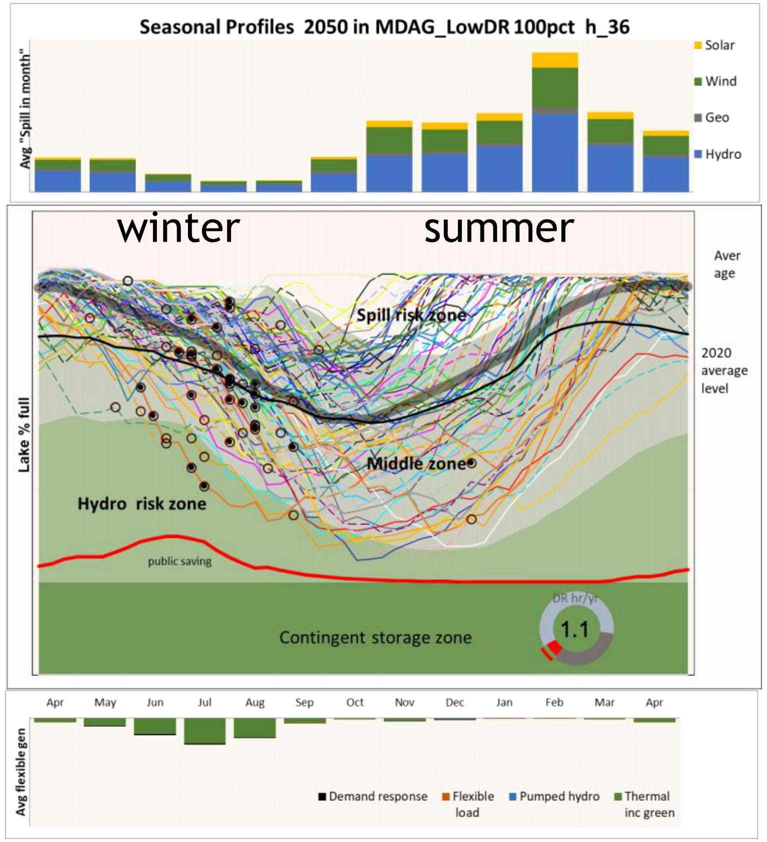
The higher flexible load has a modified seasonal demand shape and lower spill

Lake level trajectories are similar in the reference and low demand response cases in 2050 as well

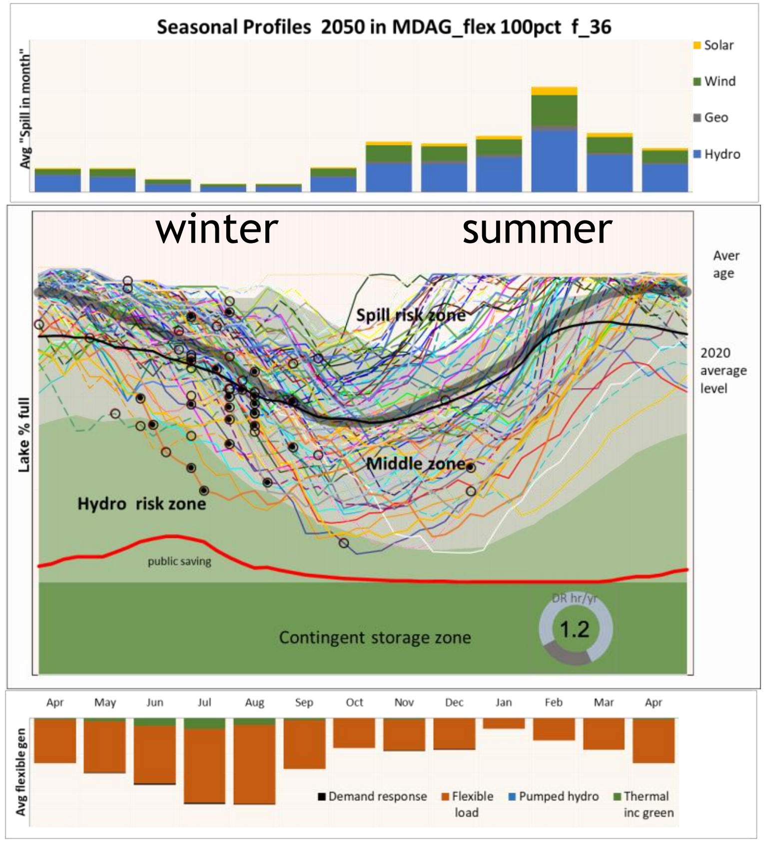
Reference Case



Low Demand Response Case



High Flexible load case



The middle hydro offer case is the same as our original reference case.

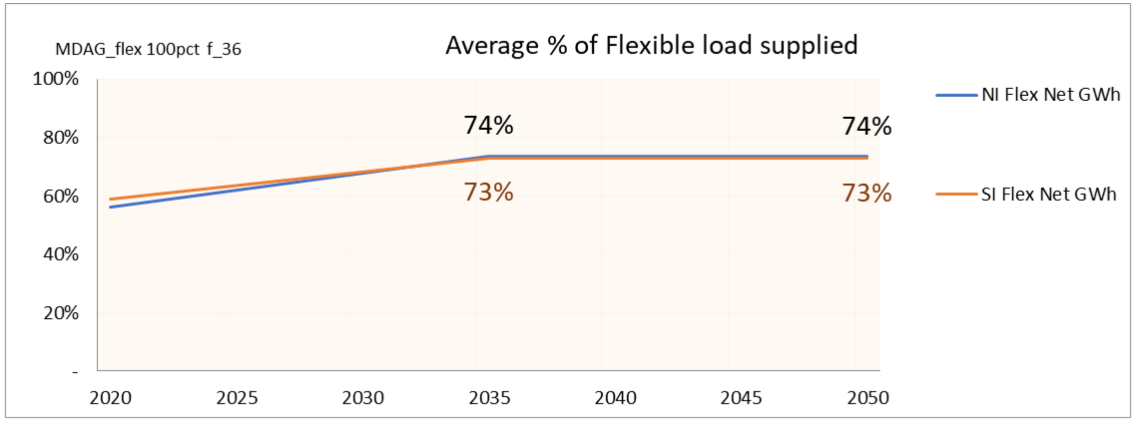
The low demand response case is very similar to the reference case except that there is a little more shortage and slightly less spill (2nd order impact of having more green peakers)

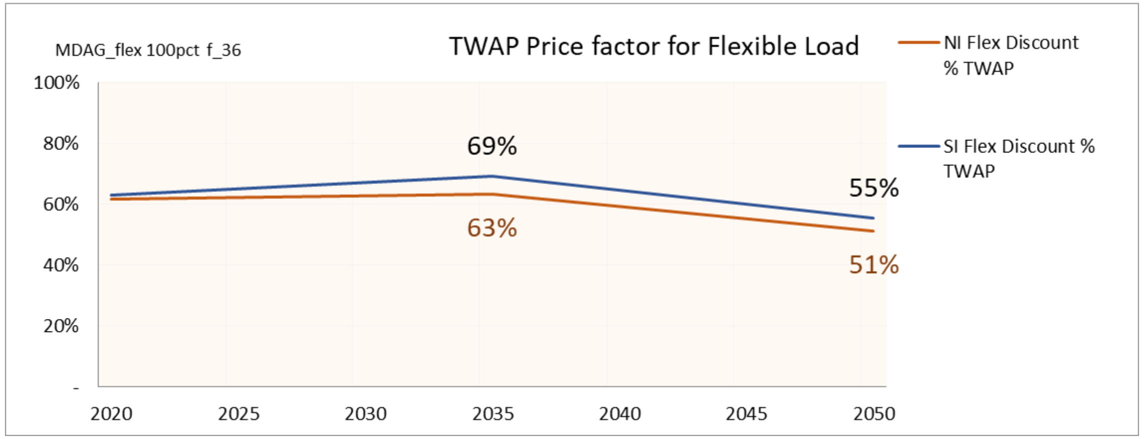
The higher flexible load has a modified seasonal demand shape and lower spill

Fully flexible load can be very valuable to the system and can earn substantial discounts relative to inflexible reference load

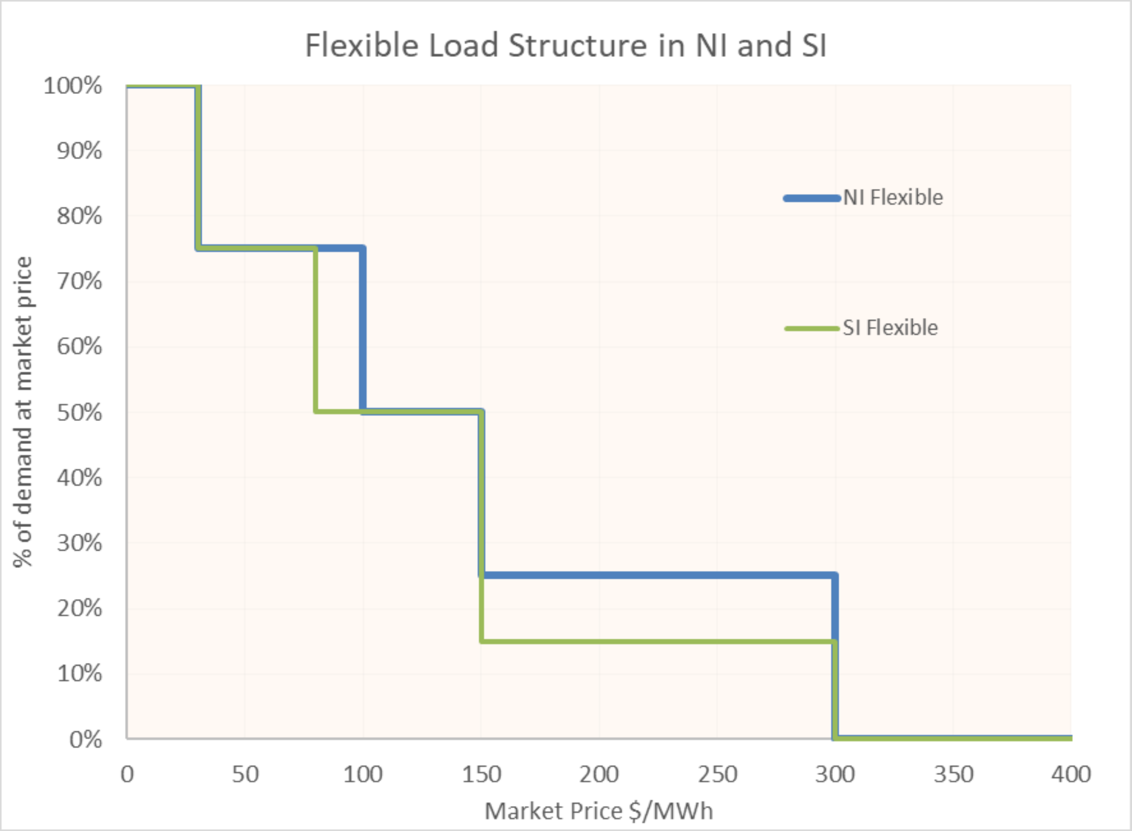
On average around 75% of the nominal flexible demand is served, but significant price discounts are available if the demand is fully flexible. These discounts increase from around 30% to over 45% by 2050.

Demand curve assumed for flexible load in each Island, each is assumed to curtail above $300/MWh and back-off to 50-25% above $150/MWh. Each flexible load is assumed run at 75-80% at prices below $100, and boost to 100% at prices below $30/MWh.





Note that the modelling assumes that demand is fully flexible within the day, over the weeks and year by year. The price discounts for only partly flexible load can be substantially less.

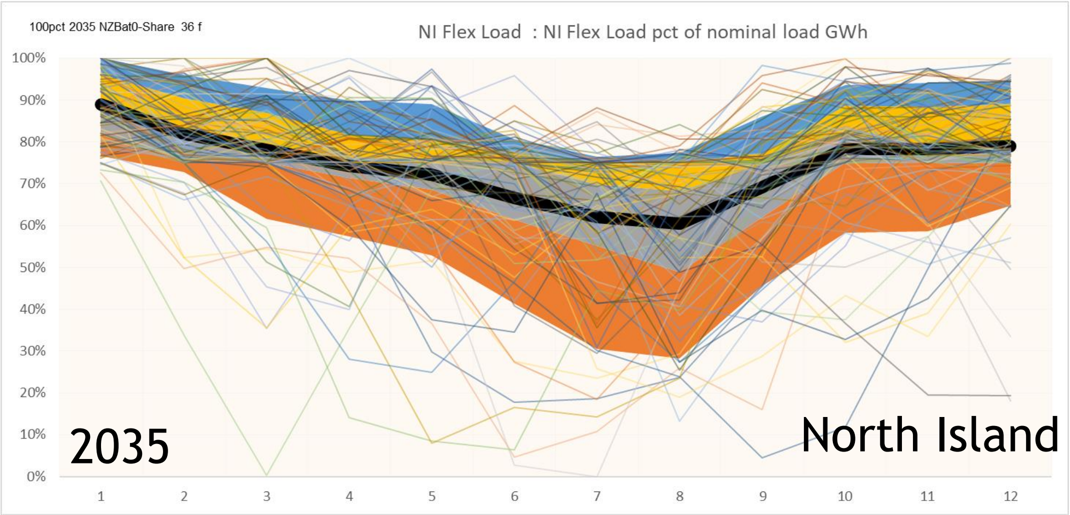


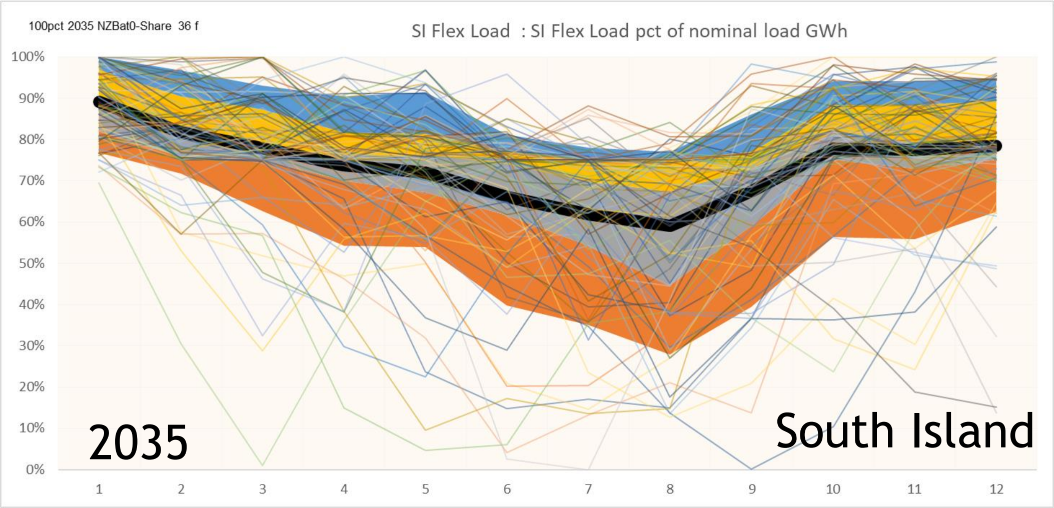
Patterns of flexible load generation by month and weather year

North Island – flexible load reduces during periods of low wind during the winter and increases during the summer when the risk of spill is higher

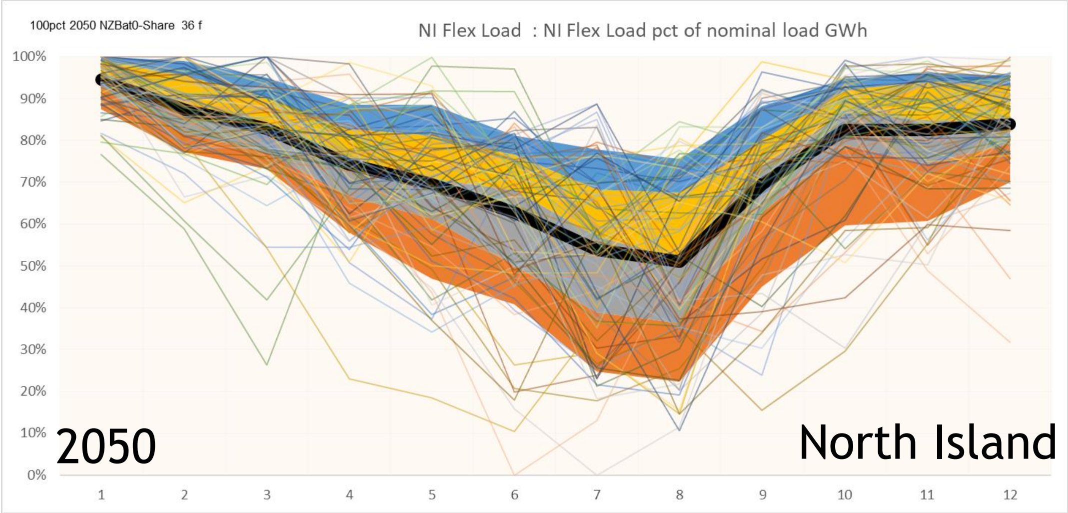
South Island – follows the same logic. Note that there are occasional months when the flexible demand is not supply at all.

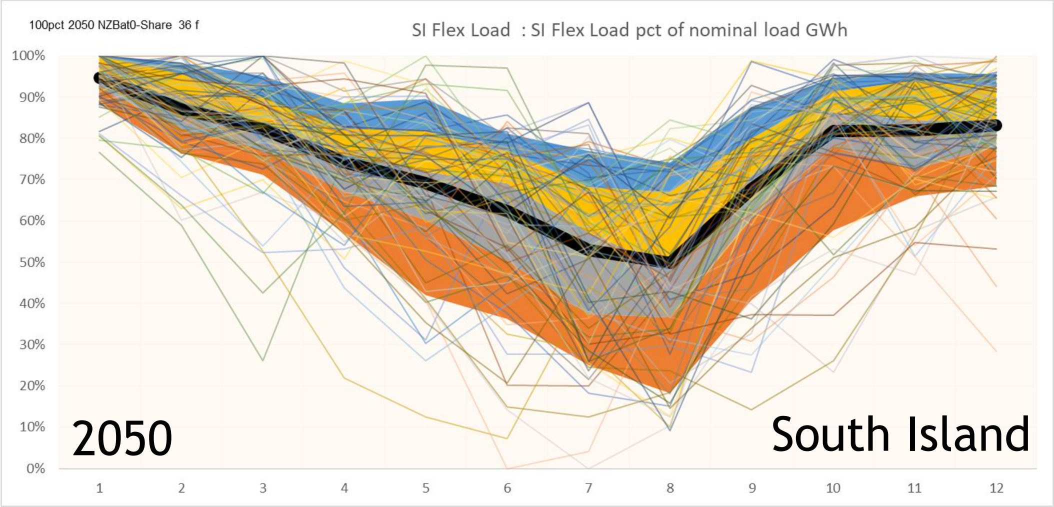
% of flexible monthly load supplied





% of flexible monthly load supplied



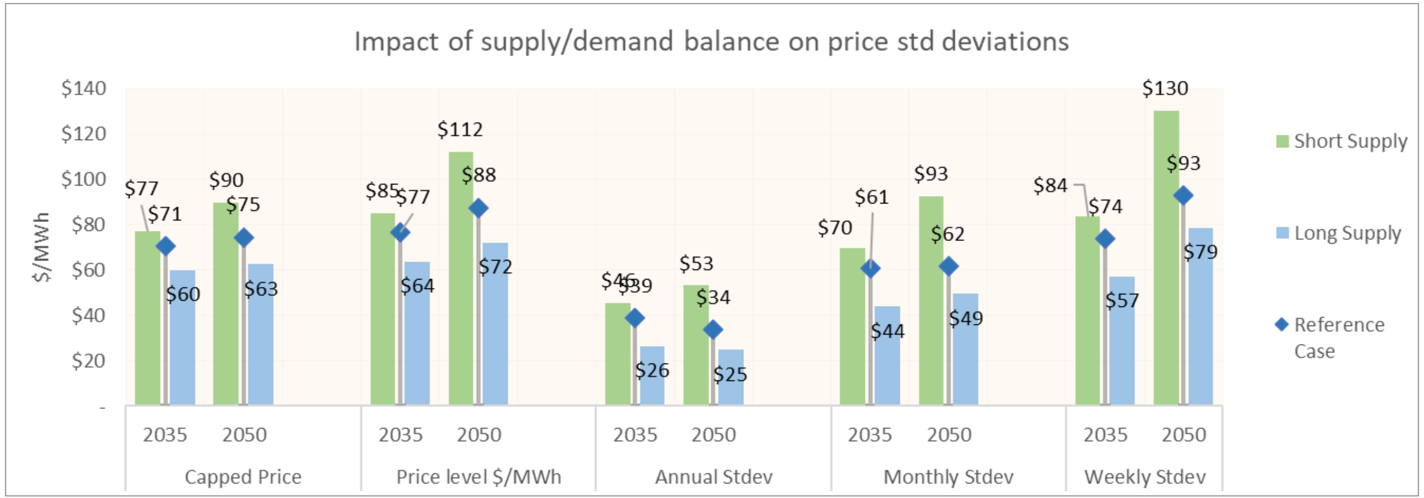


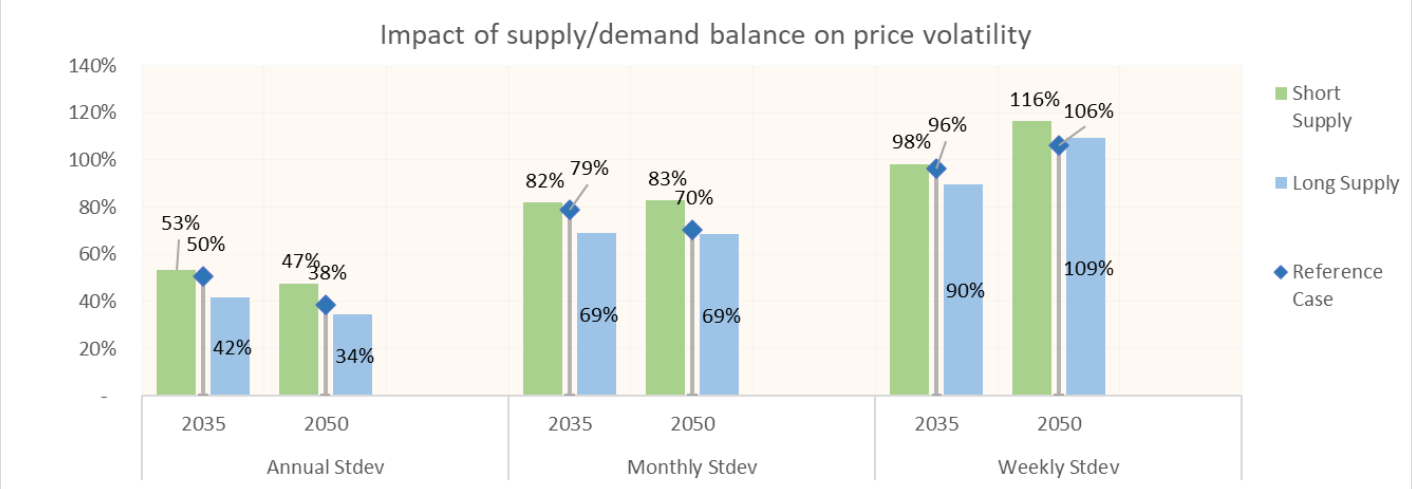
Note: the fine lines show results for each simulated weather year, the solid black is the average over all simulated years, the coloured bands are 10%, 25%, 50%, 75% and 90% percentiles.

SYSTEM MARGIN SENSITIVITY CASE RESULTS

System margin balance has a big impact on price level but a much lower impact on price volatility

Changes in the level of renewable supply resulting from investment timing or lumpiness variations of the order of ± 0.5GW





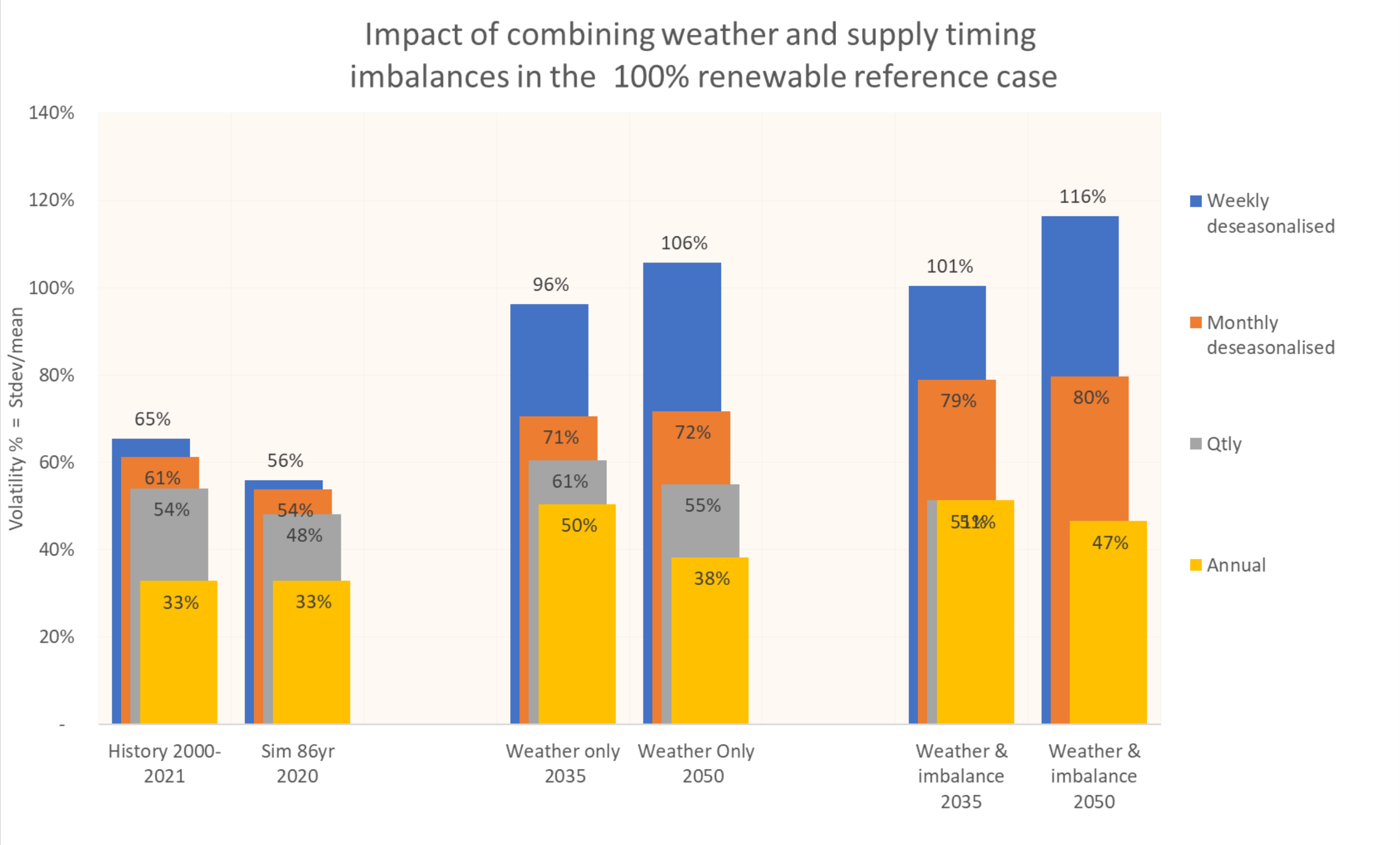
Note: The Capped price level excludes the impact of prices above $300/MWh.

Commentary

- We assume a change in the supply of new renewables of around ± 0.5GW of renewable capacity in 2050 (a mix of wind and solar). This is equivalent to around 1.5 years of the annual renewable investment during the 15 years from 2035 to 2050.
- This has a significant impact on the expected level of prices as indicated in the chart of around ± $10/MWh in 2035 and ± 20/MWh in 2050.
- The change in the level of prices flows through to the standard deviation estimates, but the volatility expressed as a % of the mean prices in each case is on the order of 2-10%.
- These results treat system margin as a known variable - either short/long/base
- In practice, it will be unpredictable and may oscillate up and down
- Ideally, this unpredictable variation in system margin should be convolved with the weather driven volatility already estimated
- The effect of this is shown in the next slide.

Combining system margin variation with weather effects increases the overall volatility by around 2-5%

Adding the supply and demand imbalances (of the order of ± 0.5GW) with weather driven variations adds around 5-9% to the volatility measures derived from weather variations alone.



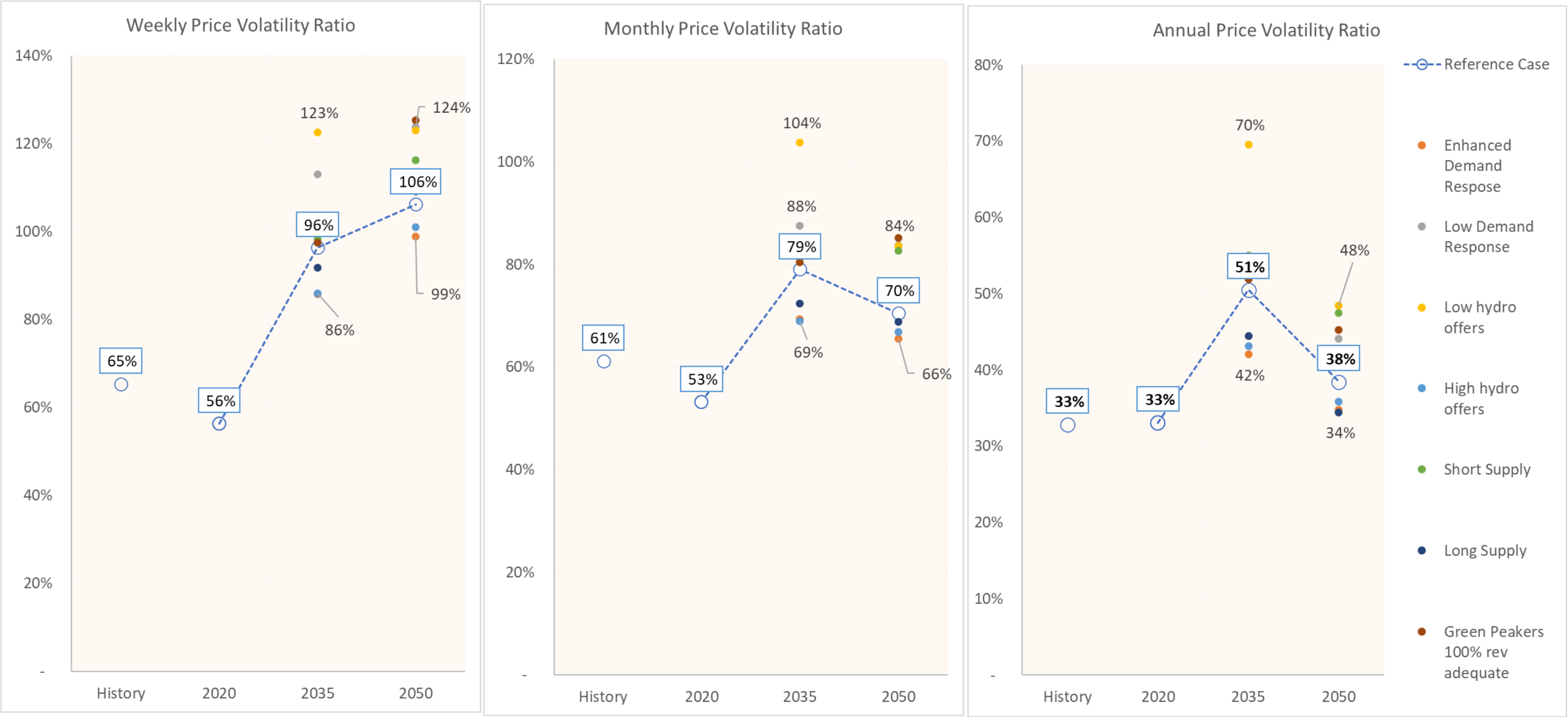
Notes

- We are not aware of any reason to suggest weather-related volatility and system margin will not be correlated
- Assuming they are independent, the combined volatility is derived assuming equal weights on the 3 supply/demand imbalance scenarios and then combining the results for the 3*86 simulated years.
- The same method for de-seasonalising the monthly and quarterly results is applied to the expanded set of scenarios.
- The effect of adding extra supply and demand lumpiness and timing imbalances is relatively modest
- This seems surprising at first, but the weather driven volatility by itself is significant (larger than system margin stand-alone effect) - and if system margin is independent it does not materially alter the volatility.

SENSITIVITY CASE SUMMARY

Summary of sensitivity runs on weekly, monthly and annual price volatility ratios

The largest upwards impact on volatility is low hydro offers and the largest downward impact is enhanced demand response and high hydro offers.

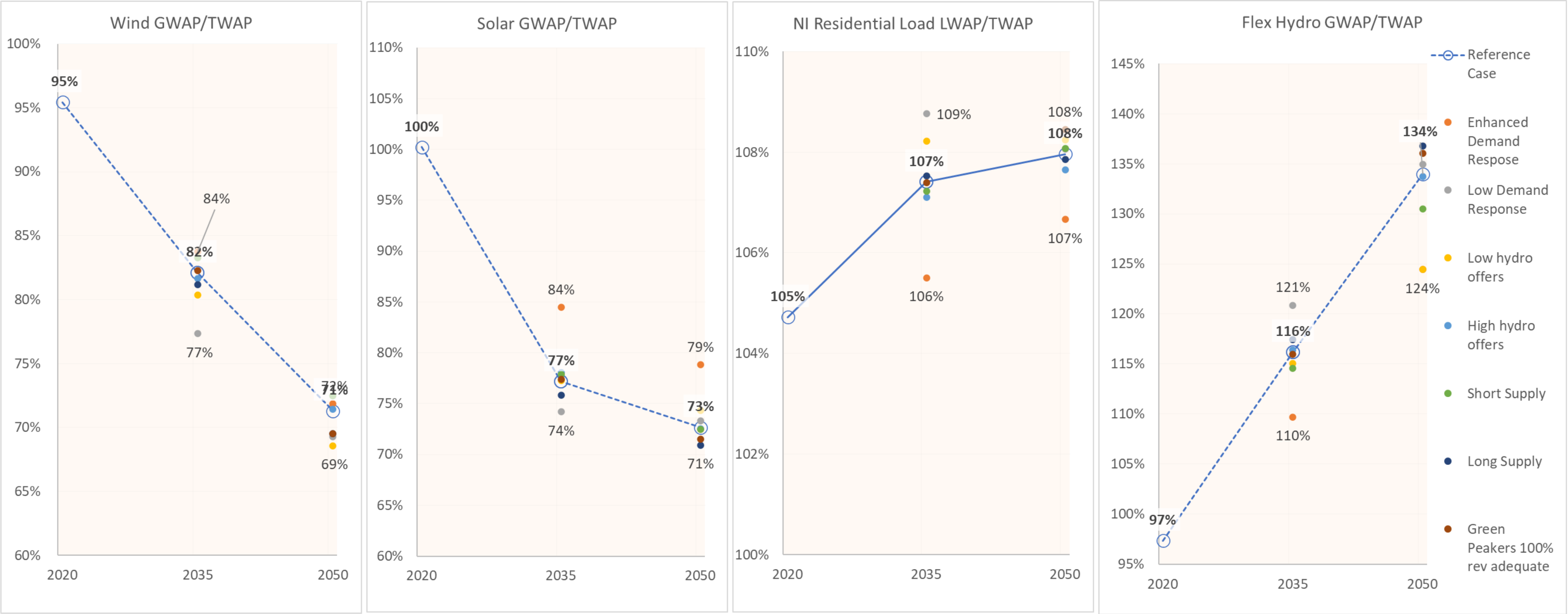


Observations

- **In summary:**
  - **The highest price volatility results from:**
    - the low hydro offers,
    - low demand response,
    - the 100% green peaker revenue case.
  - **The lowest price volatility arise from:**
    - the enhanced demand response case,
    - the long supply case,
    - the high hydro offer case.
  - **The general trends of increasing price volatility are consistent across the sensitivities**
    - particularly for weekly volatility
  - **The trends for annual results are less consistent**
    - mainly as a result of moving towards greater capacity constraints in 2050 compared with 2035

Summary of GWAP/TWAP sensitivities

The trends over time in the GWAP/TWAP ratios are consistent for each - downward for wind/solar and strongly upwards for flexible hydro, and weakly upward for a residential demand profile (mainly driven by seasonal factors)

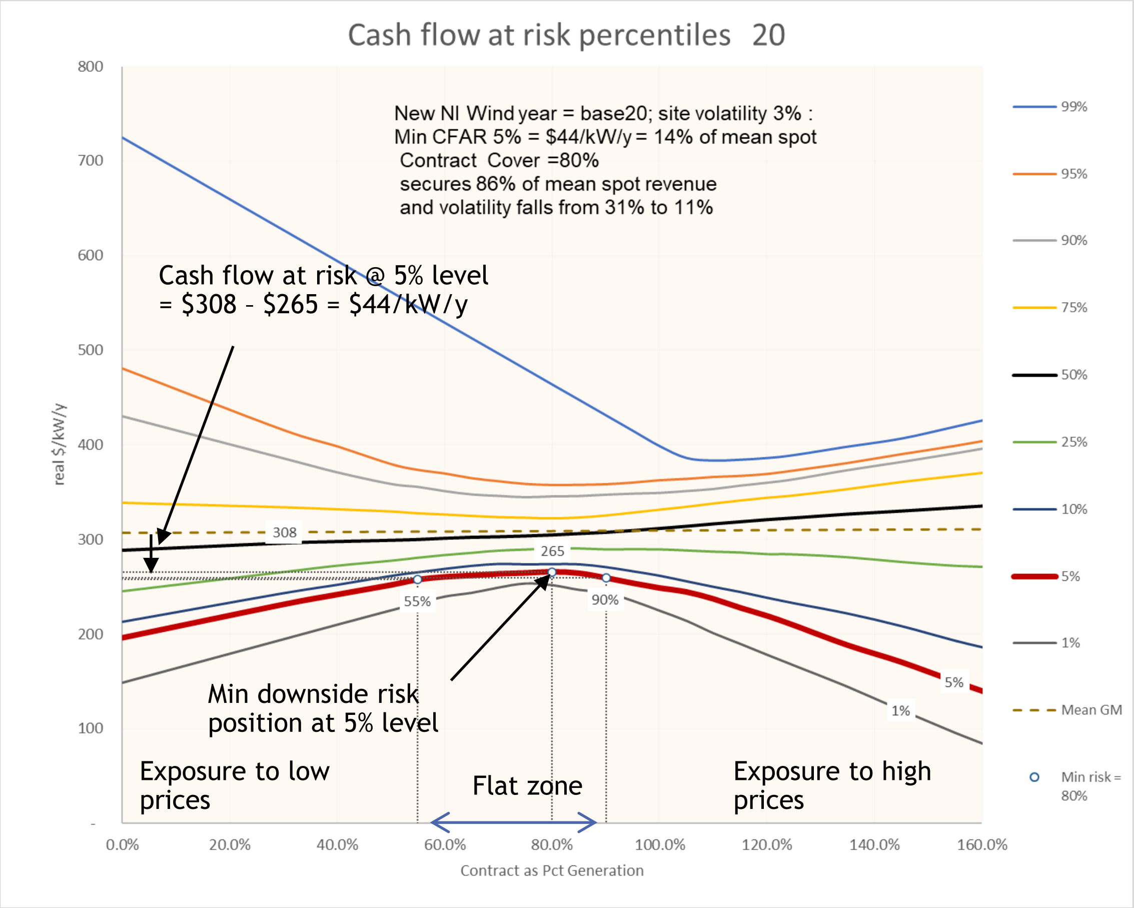


The wind GWAP/TWAP is affected by hydro offering, but not solar. Enhanced demand response increases solar and wind GWAP/TWAPs and reduces load and flexible hydro factors.
Low demand response increases load LWAP/TWAPs, as does low hydro offers.

PARTICIPANT RISKS WITH HEDGING

It is possible to assess the scope to hedge new entrant generation revenues via conventional hedges.

The Bow-tie or Butterfly chart - shows the annual distributions of hedged gross revenues for a typical new entrant wind farm - there is a reasonably flat minimum from 55% to 90%



Explanation

- **The chart shows the distribution of hedged revenues for a typical wind farm investment for a range of levels of contract cover. This chart uses simulated results of spot market earnings and wholesale spot prices over 86 weather years for the current system. It includes volume, price and GWAP/TWAP ratio risks.**
    - It does not include basis risk for this sample calculation but can if required.
  - **In this case a simple flat ASX hedge over the year is assumed**
    - Other contract structures are considered later.
  - **The x axis is the percentage of expected annual generation that is hedged by a flat contract over the whole year.**
    - At 100%, the hedge would be a flat MW at the total mean generation/hours in year.
  - **The y axis is the level of hedged gross spot market returns.**
    - For each level of contract cover from 0% to 160%, the separate lines show the percentiles of the hedged gross revenue.
    - It is assumed that the generator will attempt to hedge to minimise the downside risk at the 5% probability level. This 5% risk level is indicated by the red line.
    - This hedging of weather-related volume and price risk can be achieved via a long-term hedge, or by a rolling hedging strategy which achieves the desired level of annual cover.
    - The latter will be exposed to additional (non-weather) related fluctuations in 1-3 years ahead contract prices.
  - **With this simple hedging structure, contracting to 80% of expected volumes at the mean TWP will ensure there is only a 5% chance that net returns will be $44/kW/y less than the expected spot revenue.**
    - In equilibrium mean unhedged gross margin is sufficient to pay for fixed new entry costs.
    - The volatility (Std Dev/mean) in weather driven annual returns is reduced from 31% (unhedged) to 11% (hedged to 80%).

Note: this analysis is based on several simplifying assumptions (e.g. that participants can make a reasonable estimate of the volatility and correlation of their wind or solar resource with other intermittent supply and the correlation with market spot prices). It also focusses on annual cashflow variability only, whereas quarterly, monthly and weekly variability might also be important for financing and cashflow smoothing. Also, it does not capture the longer-term technology and international market fluctuations, but rather just the short-term weather-related factors. Nor does it consider the supply and demand for hedging products and the price premium or discounts that might arise; nevertheless, the analysis can provide a basis for comparing the current situation with around 85% renewable supply against a future with 100 renewable supply.

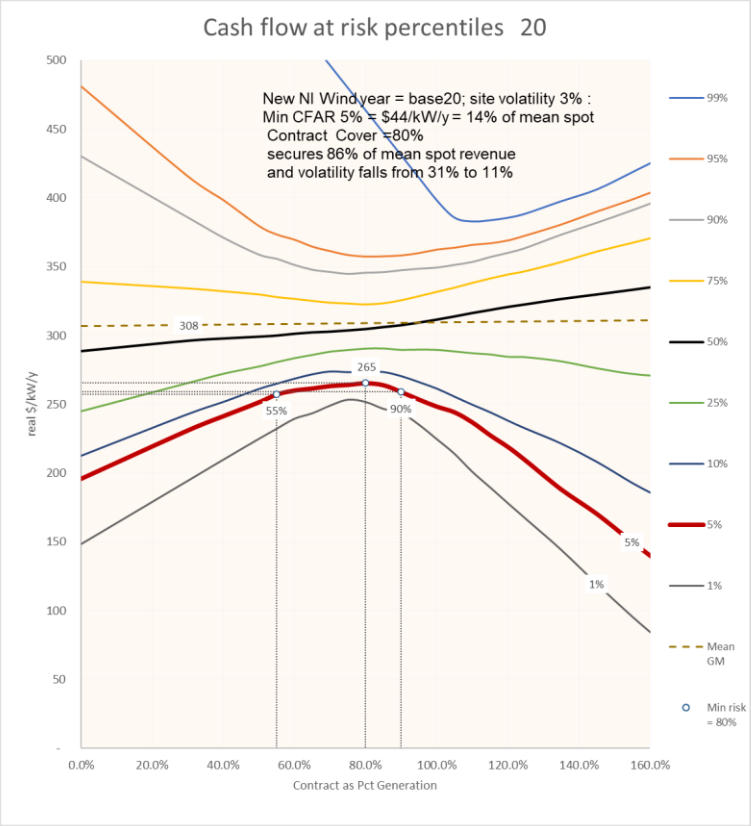
After hedging around 80% of wind output, net revenue volatility is reduced from 30% to 10% in 2020. By 2050 the hedged volatility increases to 14 -16%.

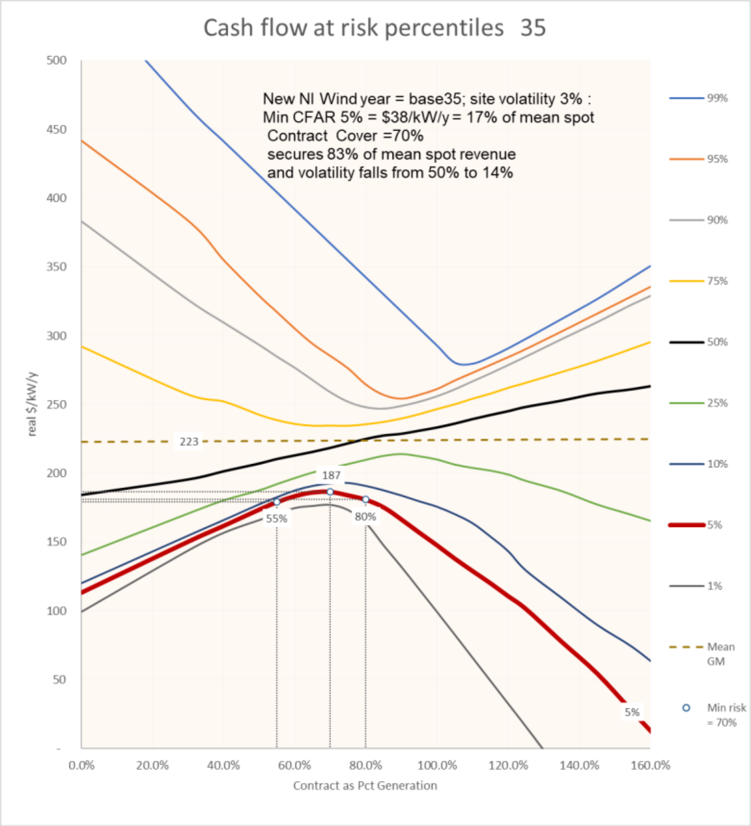
With the simulated 2020 system, weather volatility downside risk can be minimised by contracting to 80%. This secures 87% of expected revenues at a 5% risk level – giving a Cash flow at Risk (CFaR) value of 14%.

By 2035 the increased spot price volatility results in a lower contract cover to 70%, and a 3% increase in CFaR and a 3% increase in hedged revenue volatility

By 2050 the optimal contract cover falls to 60% and CFaR increases but spot price volatility reduces.

Wind faces extra volume/price risk as % wind on system increases.



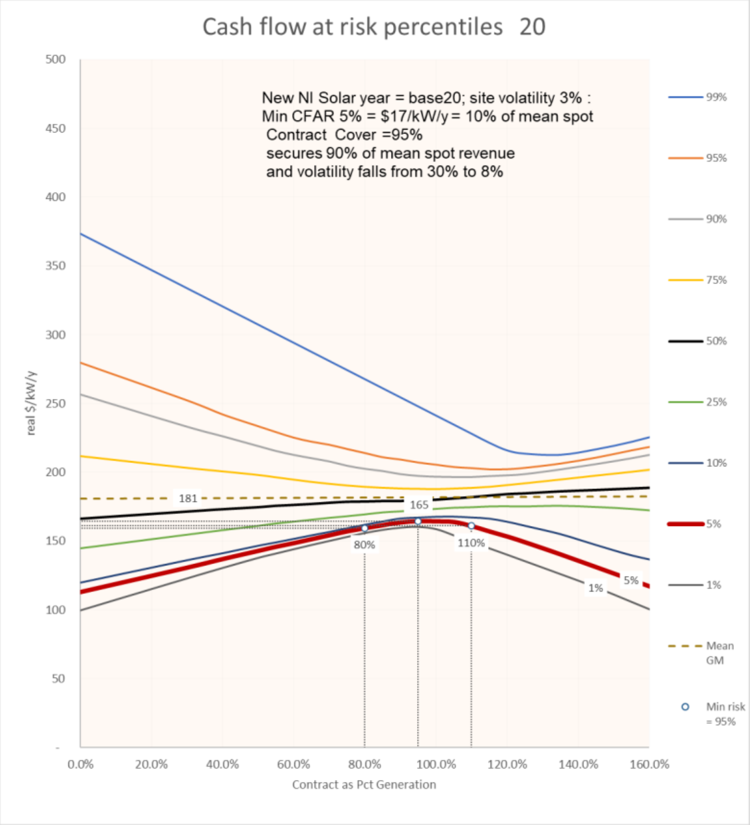


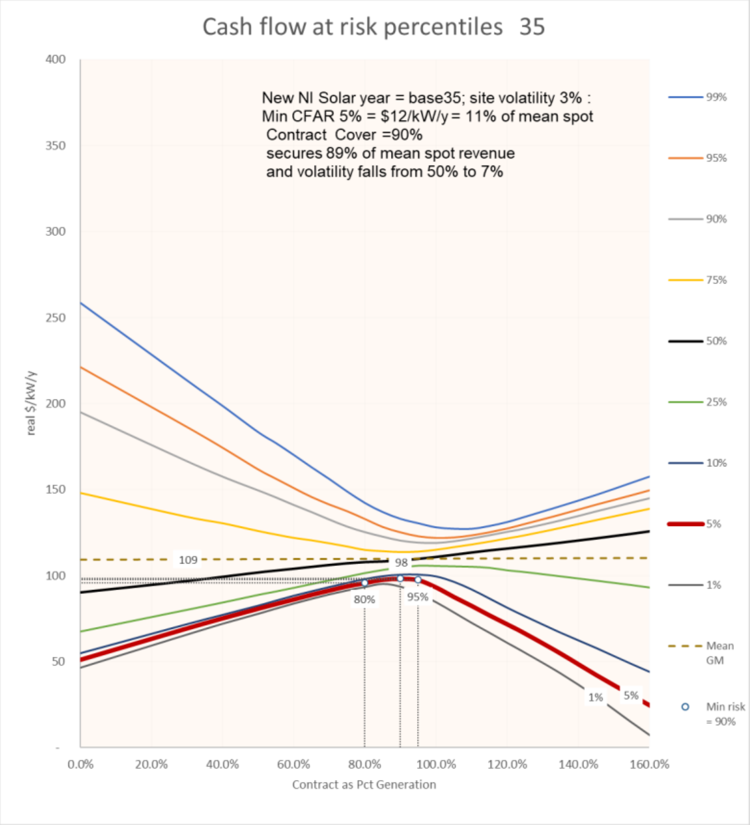
Reference case for a typical solar with a winter / summer volume shaped flat hedge

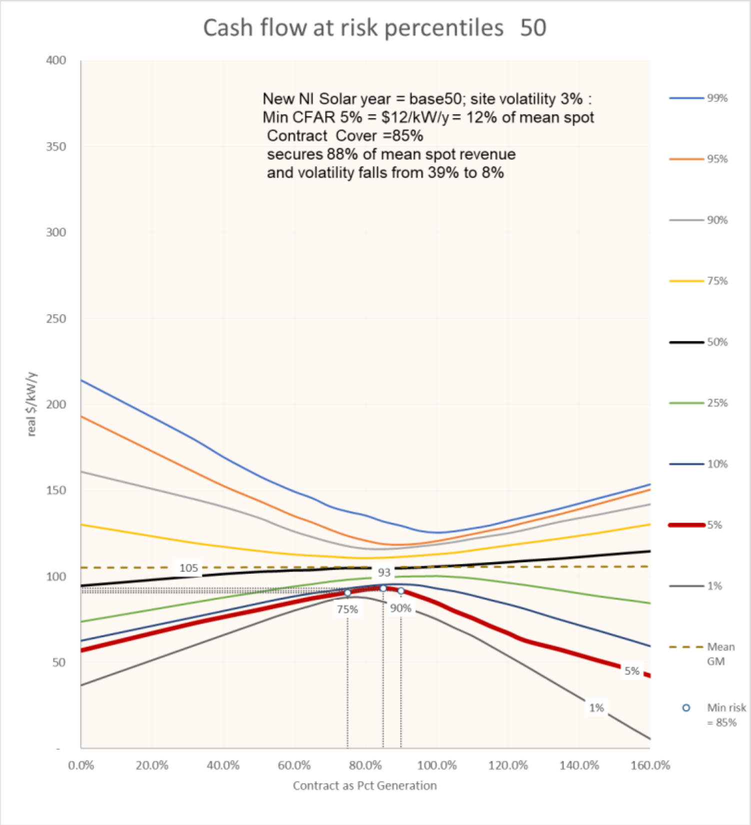
The reference case assumes a seasonal summer oriented contract shape (30% lower MW over winter). This results in a CFaR of 11% of mean revenue at the 5% level.

The higher spot revenue volatility in 2035 reduces contract cover slightly to 90%, but only increases the CFaR 1%.

The spot revenue volatility is lower in 2050, the optimal contract level reduces to 75% and and the CFaR only increases 1%.





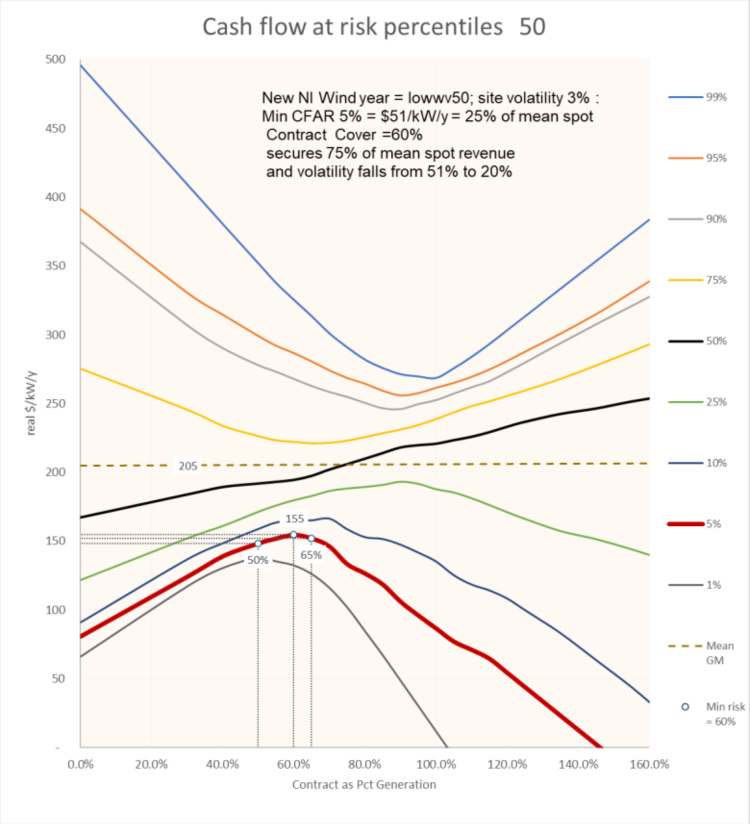


Note: the modelling is based on a broad utility scale solar profile, with an additional site specific additional independent volume volatility of 5%. Solar has a typical annual volume volatility of around 3% .

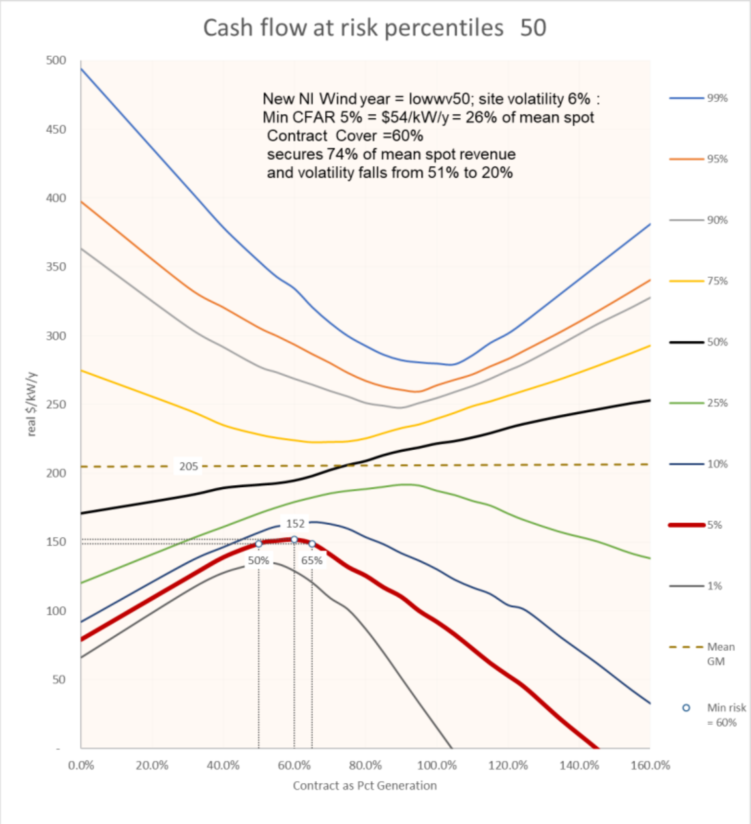
Impact of higher price and volume volatility on wind cash flow at risk

This shows the reference case in 2050 with flat hedges

This shows that the impact of higher price volatility arising from the low hydro offer curve sensitivity does not change the optimal contract level, but increases the CFaR from 23% to 25%



Extra site specific volume volatility leaves the optimal contract position the same but increases the CFaR from 25% to 26%

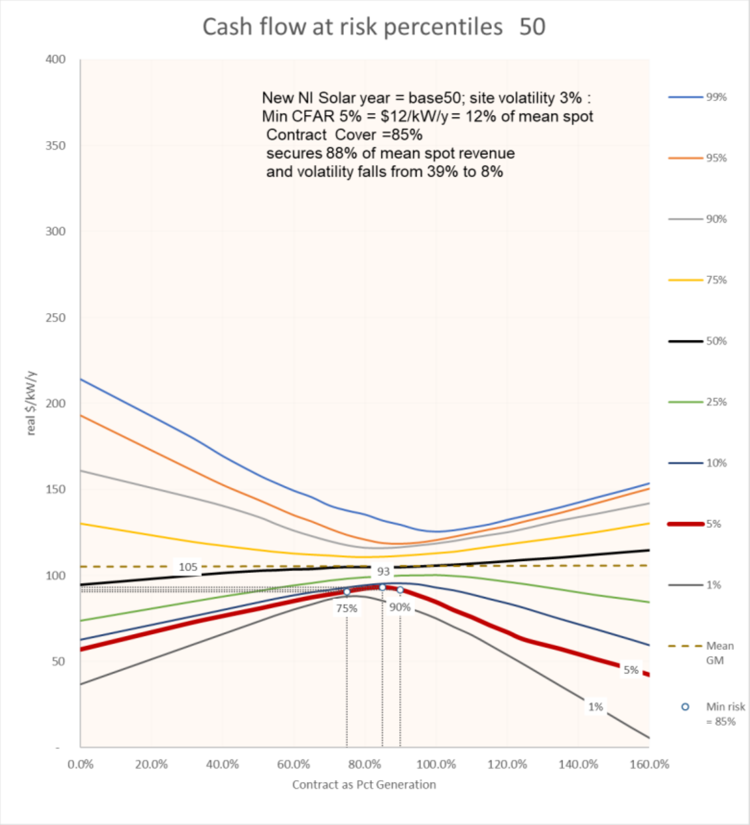


Impact of additional price and volume volatility on a typical solar new investment with profiled winter/summer firm hedges

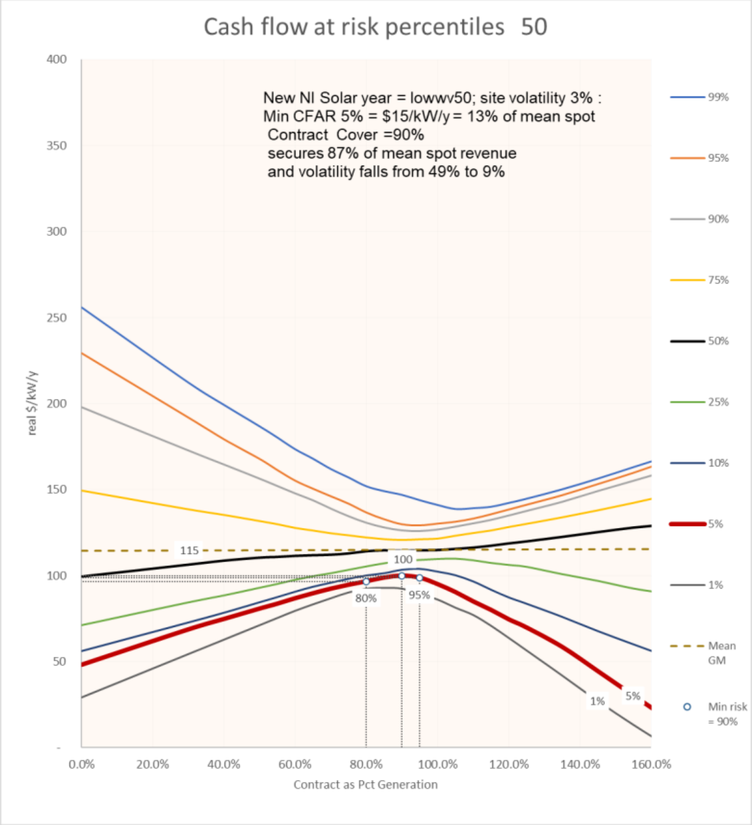
concept consulting

JC2

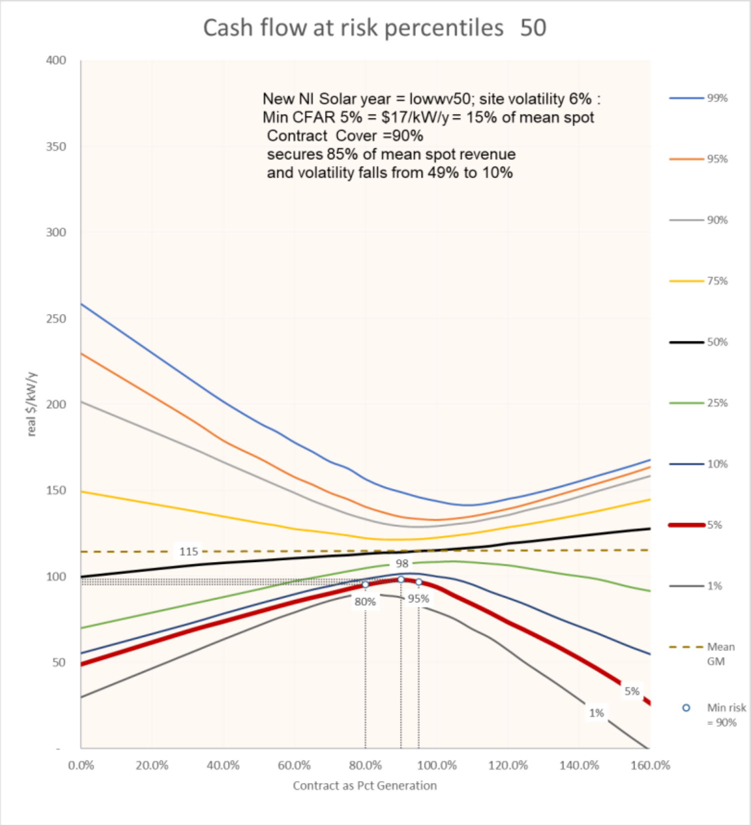
Reference case 2050 for typical solar plant



High price volatility case - the optimal contract cover is similar, but CFaR increases 1%



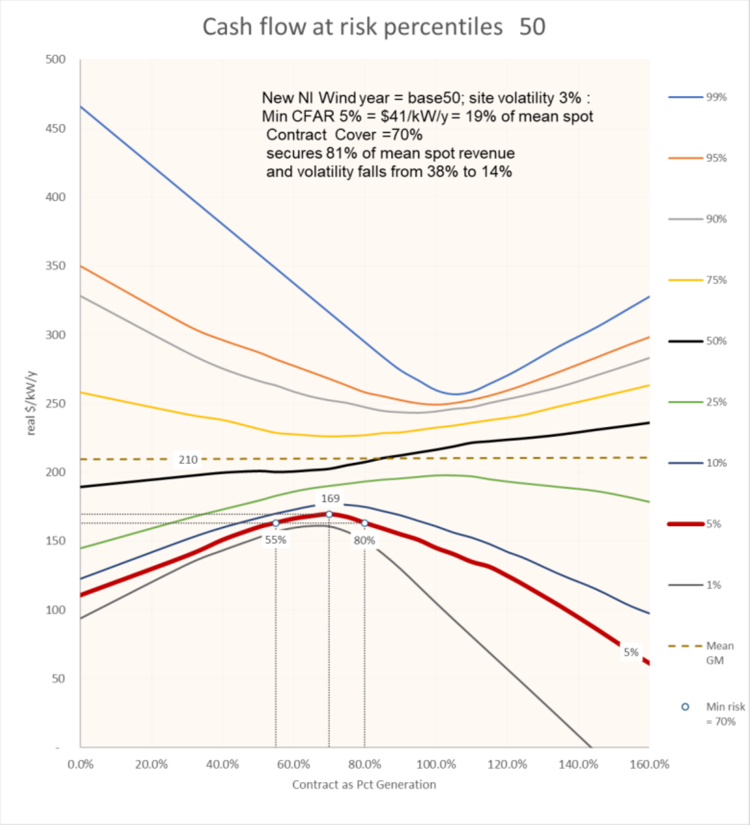
With extra site specific volatility - similar contract levels and 2% increase in CFaR



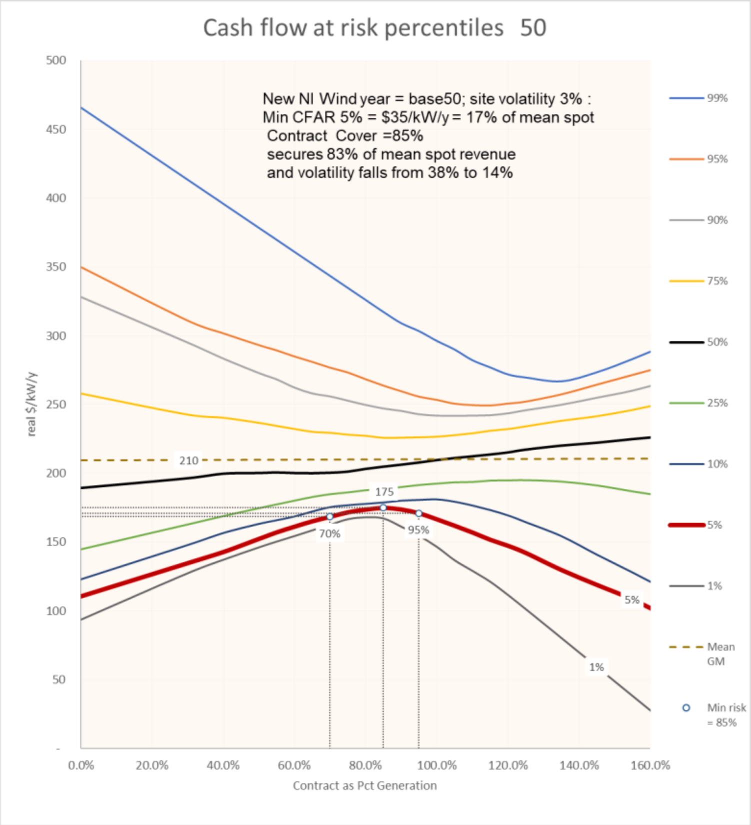
Including $300 cap contracts enables wind to sell more firm swaps, and reduces the CFaR by 6%

Reference Case in 2050 - selling a firm flat swap results in a CFaR of 23%.

… and buying 50% cap backup - enables a 10% higher swap contract level, and reduces the CFaR by 4%



… or 100% cap backup - enables yet more firm swaps to be sold and reduces the CFaR 6% to 17% 0f mean spot revenue

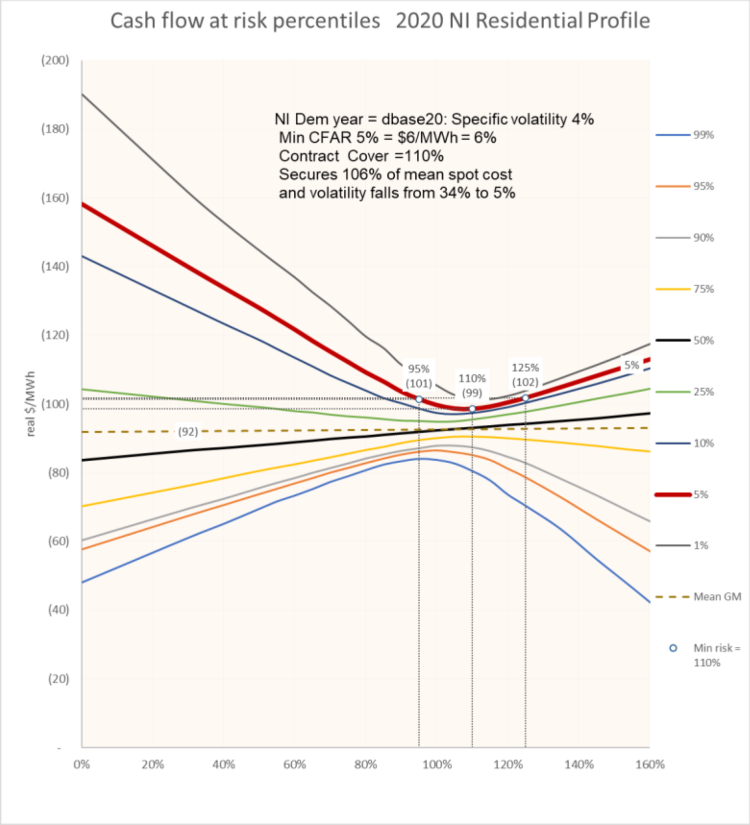


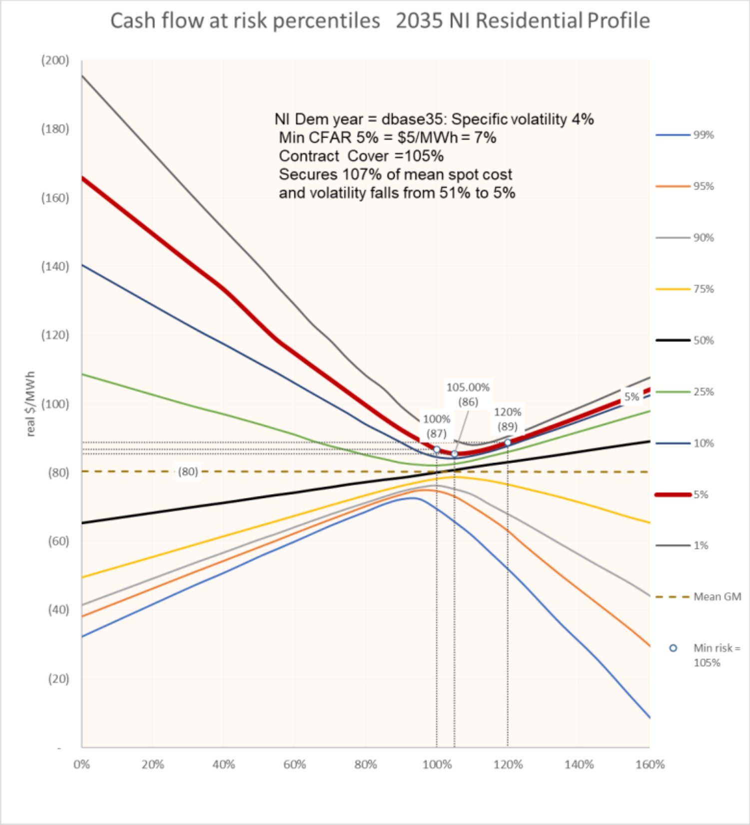
Demand side hedging – optimal is close to 110% - but could be in region of 95-125% for shaped flat swap. The CFaR at 5% level does not change significantly

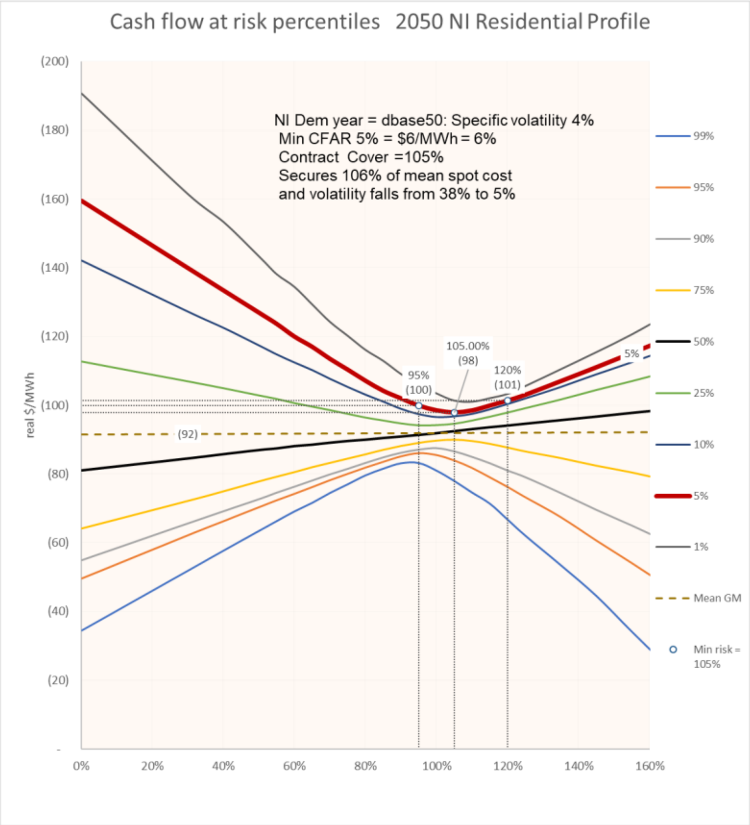
Reference Case in 2020 - shaped winter oriented firm flat swap - optimum 110% contract cover : but could be as low as 95% or as high as 125%. The CFaR is 6% of mean purchase costs.

Reference Case in 2035 - Optimum 105% - could be as low as 100% or as high as 120%. The higher volatility results in a slightly higher CFaR of 7%.

Reference Case in 2050 - The optimum contract level is the same, and CFaR reduces to 6% of mean purchase costs. Load is now less correlated with price given higher level of supply side intermittency.



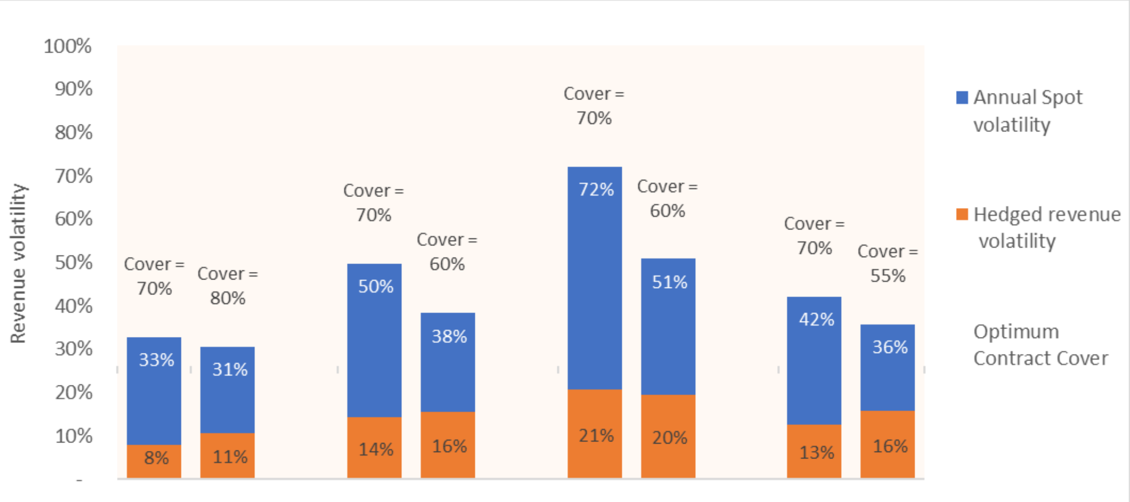


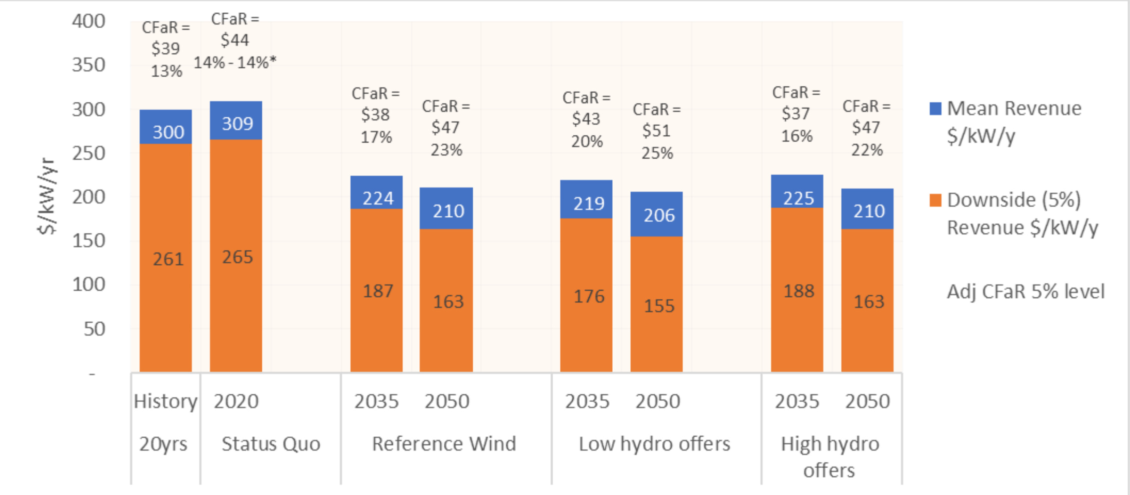


NB: Assumes a 4% annual variability in load with a NI residential shape with winter load being around 9% above annual average levels.

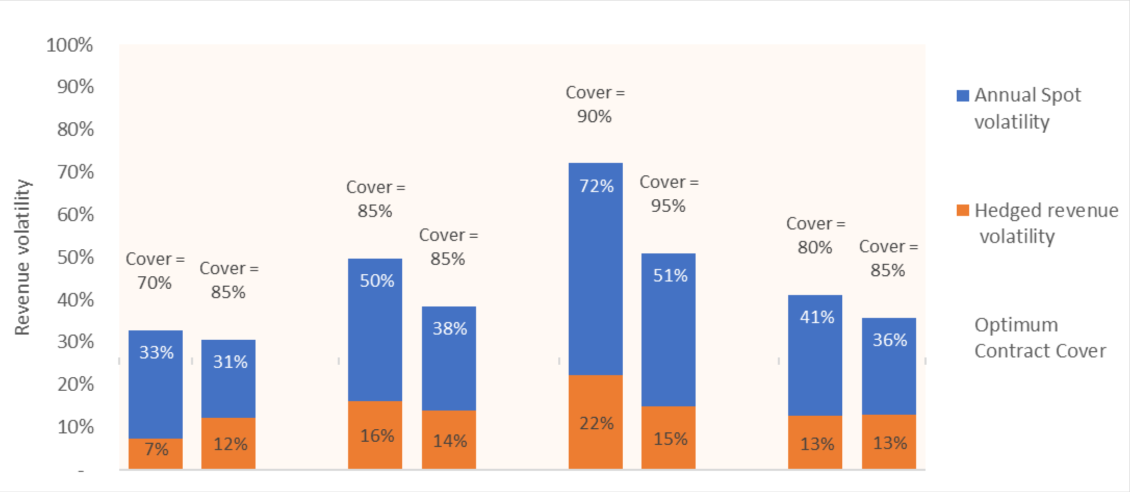
The increased spot price volatility causes optimal contract cover to fall somewhat but this can be mitigated by purchasing $300 cap contracts to provide backup

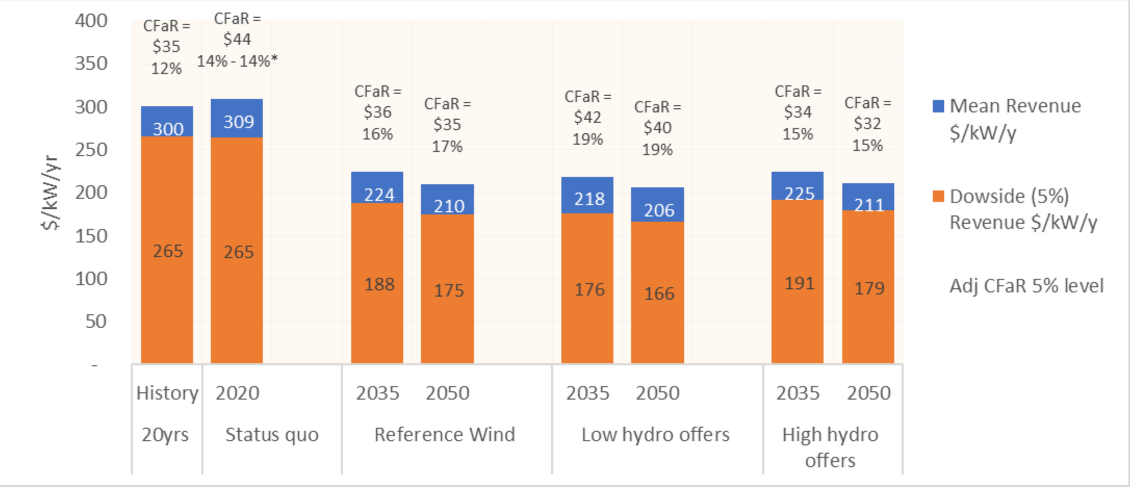
A typical wind Investor - sells a firm swap





A typical wind investor - sells a firm flat swap and buys a $300 cap for backup

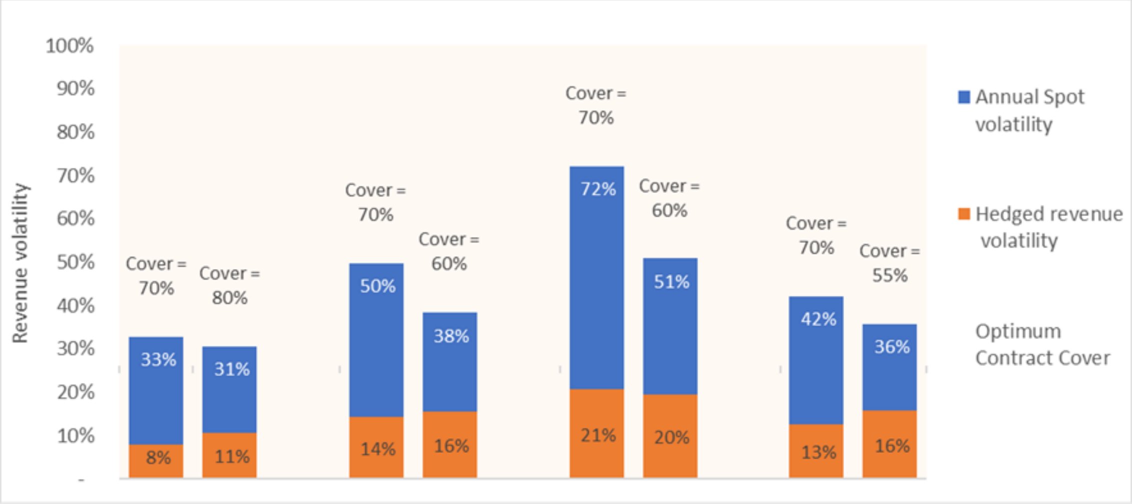


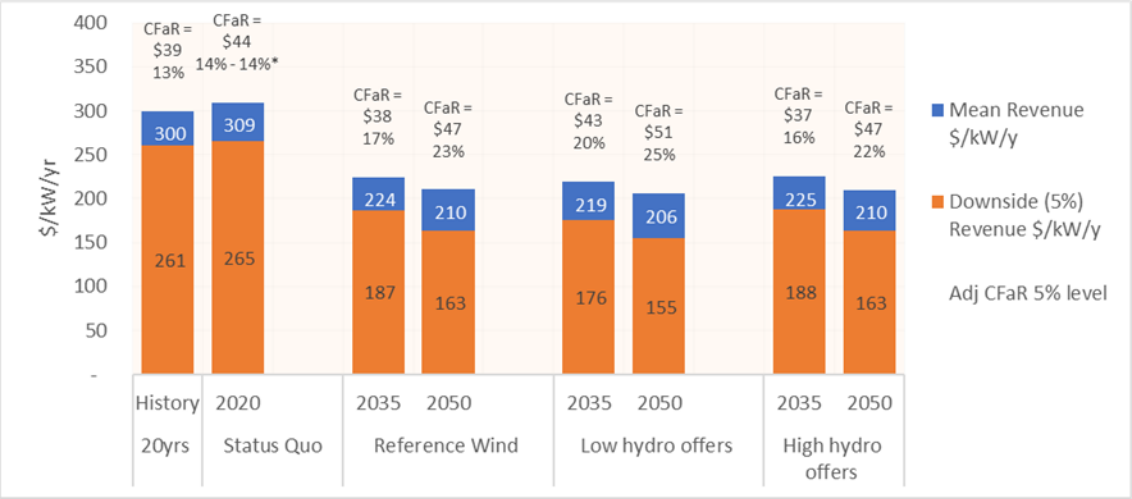


NB: The history is based on a Tararua wind profile and a Ninja upper NI solar profile for last 20years and historical real prices. The historical CFaR at 5% level is approximated based on the estimated standard deviation of hedged revenues over 20years and assuming hedged revenue can be represented with a normal distribution.

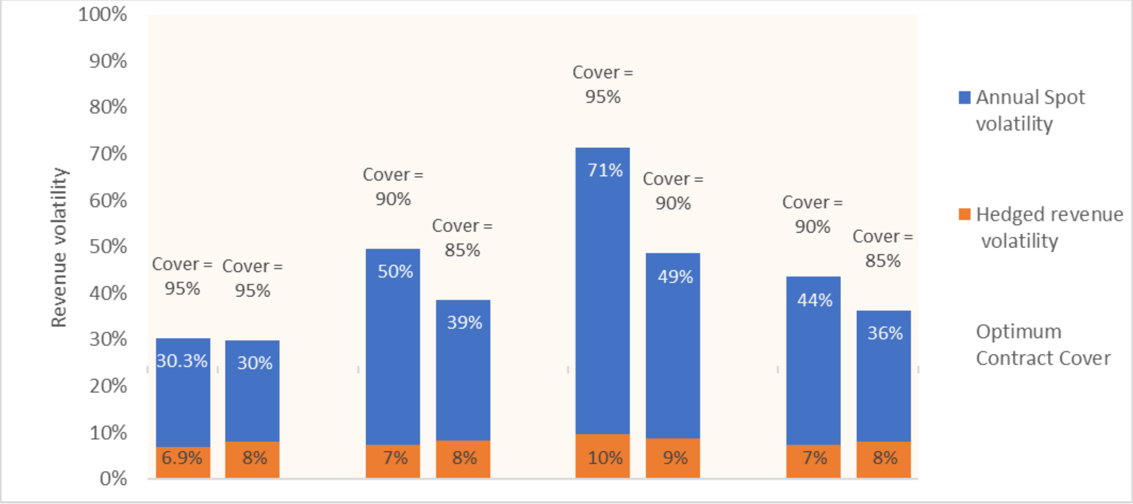
The residual risks after optimal hedging with simple seasonal profiled hedges is expected to increase more for wind than solar

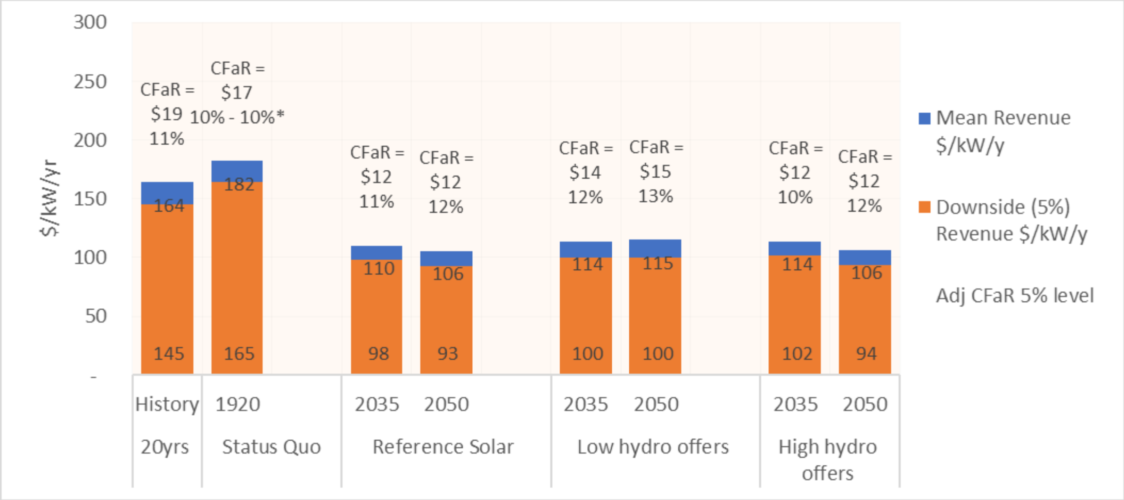
A typical wind Investor - sell a firm swap





A typical solar investor - sell a winter/summer shaped firm swap

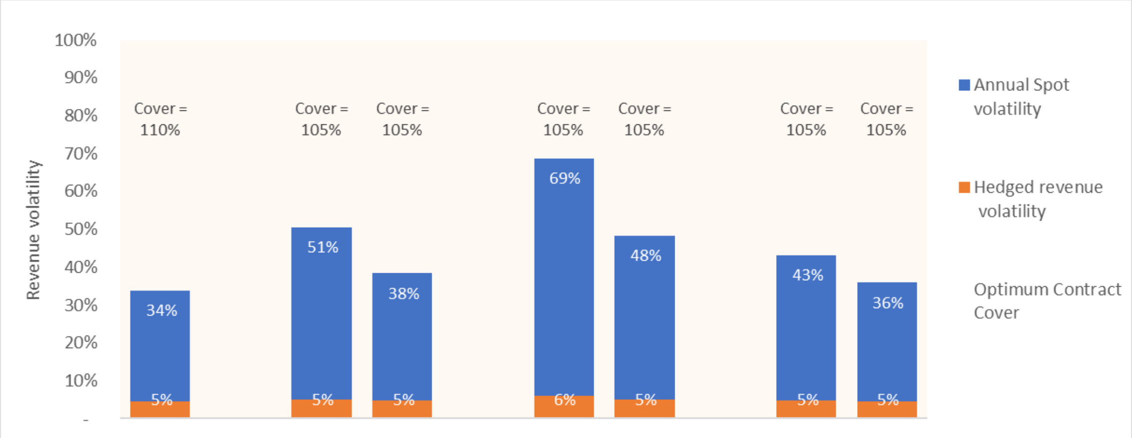


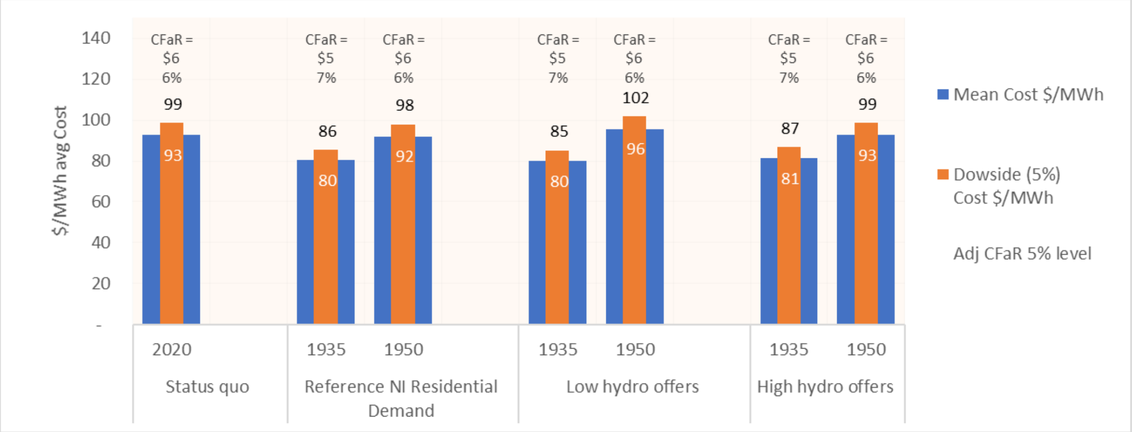


NB: The history is based on a Tararua wind profile and a Renewable Ninja upper NI solar profile for last 20 years and historical real prices. The CFaR at 5% level is approximated by the minimum annual revenue over 20 years.
(*) The upper CFaR % in 2020 has been adjusted to reflect the % of the required new entry revenue to be comparable with the 2025 and 2050 target years.

We expect only slightly higher upside risk on retail load hedges if an optimal hedging strategy of around 105% above demand with a 9% higher winter than summer profile.

Hedging a typical NI residential profile





Comments

- The downside annual cost risk for retailers is not expected to change significantly if they continue to hedge with flat contracts somewhat above expected load profiled on a summer winter basis.
- This is somewhat surprising given that a substantial increase in price volatility is expected.
- The reason for this is that the correlation between retailer's demand and spot prices is expected to reduce as weather variations relating to solar and wind become a more significant factor than demand in causing spot price variations as the penetration of these intermittent supply sources increases.
- That said, it is expected that there will be an increase in the demand for new more sophisticated hedging (including with-in day profiling and cap products) to manage shorter term variations in the wholesale costs on a weekly or monthly time frame.

In summary we expect that 5% downside risks, after optimal rolling hedges, to increase by up to 1-10% for wind projects, up to 3% for solar and up to 1% for typical loads.

The charts show the 1 in 20 downside revenue risks for wind and solar, and the 1 in 20 upside risk on hedged load cost, after the optimal level of rolling hedges.

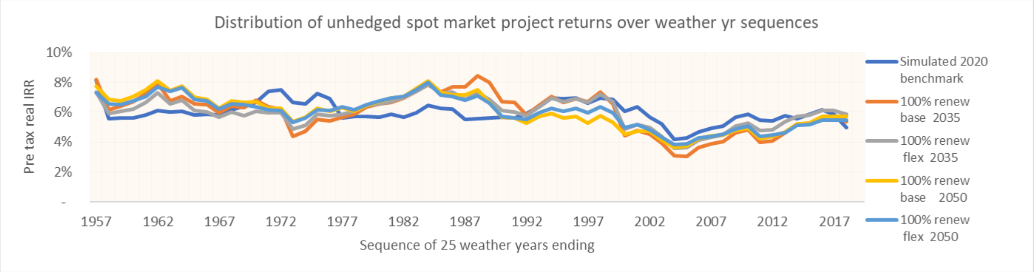
Commentary

- For wind there is no significant benefit from seasonal shaped hedges and so it is assumed that wind has a simple flat swap over the whole year at a fixed MW level.
  - **This hedging shape can reduce the downside revenue risk to around 14% of mean spot revenue now (i.e. secure 86% of mean spot revenue at 5% probability level).**
    - As we go to 100% renewable by 2050 the % of intermittent wind on the system will increase substantially, this will increase price volatility and also increase the negative correlation between wind and price.
      - This combination should see the downside revenue at risk increase from 14% up 8-11% to 22-25% (depending on different hydro offering assumptions).
    - Much of this increased risk could be hedged if wind projects could buy “backup” by way of $300/MWh cap contract.
      - In this case the downside risk increase should be limited to 1-5%.
- For solar there is a significant benefit in shaping the MW hedge down 30% in winter and up 22% in summer.
    - Ideally solar would benefit by hedging using a day/night profile, but this has not been explored here.
  - As we go to 100% renewable we expect this strategy to increase the downside revenue risk from 10% up 0-3% to 10-13%.
    - This increase in weather related annual revenue risk is relatively small compared with the other long term technology driven risk factors facing a solar investor.
- For demand there is a significant benefit shaping the MW hedge to be around 9% higher in winter and 6% lower in summer.
    - Ideally demand would also benefit from a day/night profile.
  - With this, the upside cost risk at a 5% probability is around 6% of mean spot costs.
    - It is not expected that this upside cost risk will increase by more than 0 to 1%. Although there is greater price volatility, the correlation between demand and price should decline as the % wind/solar increases.

The variability in project internal rates of return (IRR) for a typical generic wind investment is increased. The downside risk appears to be around 3-4% compared with 4% in the benchmark.

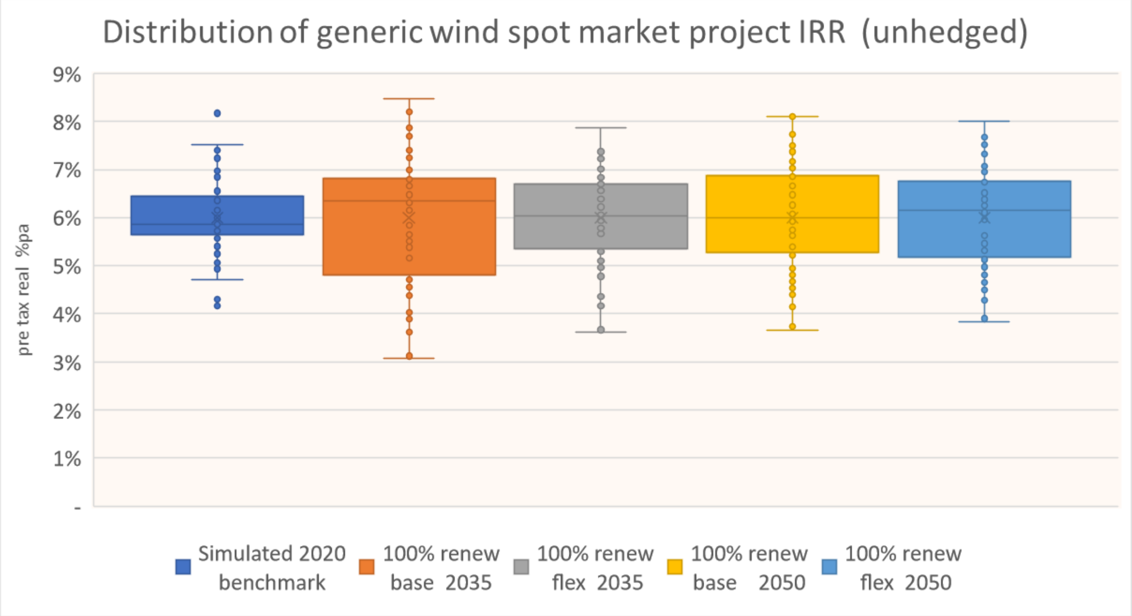
We have assessed the impact of increased spot price variability from different weather sequences on overall project returns for typical new investors in a generic wind project.

- To assess the impact of price volatility for new investments we have calculated the ungeared pre-tax project IRR for a typical wind project with a 25-year life for different sets of simulated weather years (start in year 1 through to year 60).
- This project IRR accounts for the initial capital cost and spot market earnings minus variable and fixed costs each weather year.
  - For this calculation it is assumed there is no hedging at all.
- The variability in full project returns for the 61 different sequences of weather are calculated and summarised in the chart on the right.
  - To enable a comparison of variabilities the returns are adjusted to achieve an assumed target pre-tax real 6% p.a. return in each case.



- The box and whisker chart on the right shows that unhedged project returns are somewhat more variable with a 100% renewable supply system, but the downside exposure is still around 3-4% p.a., not too much lower than the current system with a 4% down-side.
  - In reality, projects are likely to be at least partly hedged through contracts or vertical integration. This will reduce the downside risk somewhat.
- Additional flexible demand reduces the variation in weather driven project returns modestly.

There is an increase in unhedged market-based project IRRs with 100% renewables, but the downside risk remains at around 4-3% p.a. Additional flexible demand reduces the spread in returns modestly.

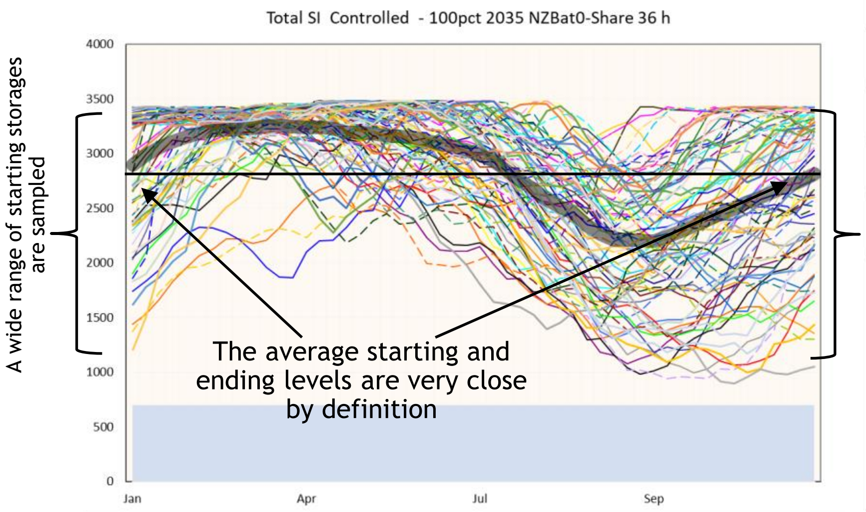


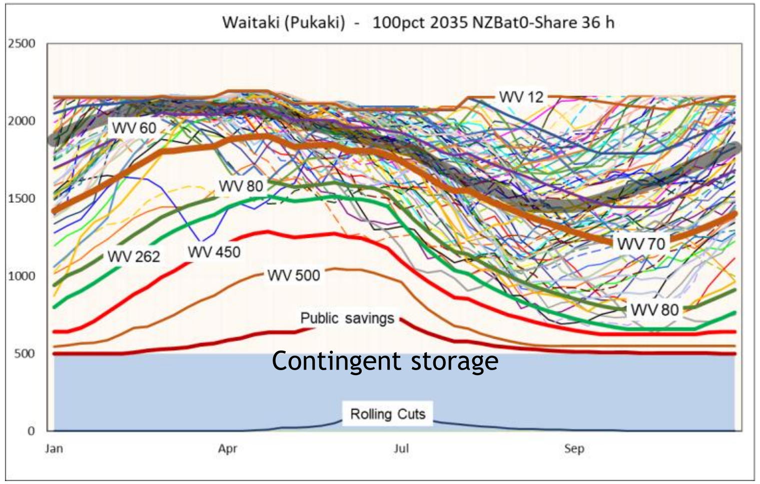
Note: the greater variability in the reference case results for 2035 compared with 2050 probably reflects the impact of the modelling approach rather than being significant. The results are derived from the same weather years, but the starting lake levels used in the 2035 and 2050 simulations are not the same and the hydro guidelines also differ. This makes comparisons between 2035 and 2050 a little more difficult in this case.

APPENDIX 1: HYDRO OPERATION AND DRY YEAR SECURITY

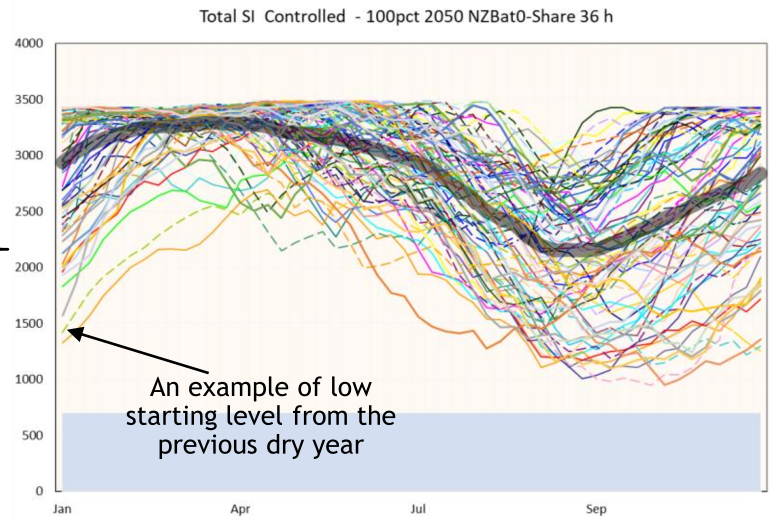
The model is producing sensible looking lake operation and dry year security in the reference case

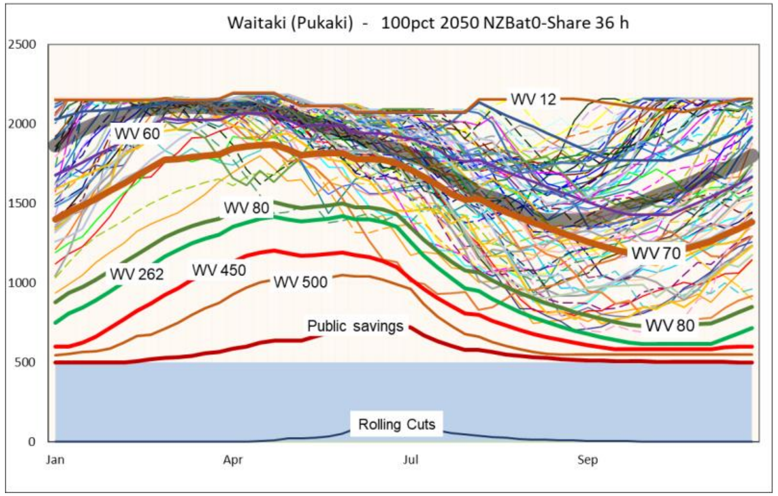
2035 - Reference case - 100% renewable





2050 - Reference case - 100% renewable



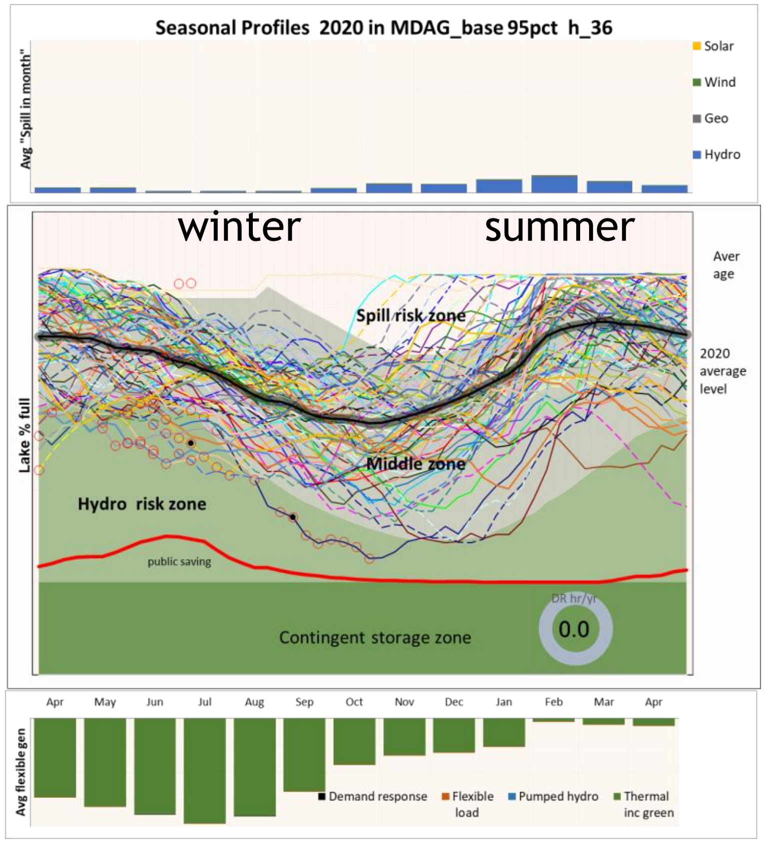


Comments:

- The offer prices on operating guidelines reflect the cost of spill when lake levels are full, and the risk of spill is high. They reflect the cost of green peakers, demand response and shortages when lake levels are low, and the risk of supply is higher.
- The guidelines are shaped to ensure that, with the level of new renewable investment, the risks of running into the contingent zone in the worst simulated sequence is very low.
- For intermediate lake levels the offer prices are set to achieve a new entry equilibrium whereby new geothermal/wind/solar are able to achieve revenue adequacy and hydro storage levels are able to be maintained at a sufficiently high level prior to winter to manage dry year risks, without a major new pumped hydro investment.
- Dry year security can be maintained with existing levels of storage capability under 100% renewables via additional renewable build to ensure that lake levels are adequate in all but the worst sequence.
- Renewable build is also driven by the need to avoid "capacity" and green peaker costs in winter days with low wind.
- Spill occurs when lakes are filled prior to winter and there is high inflow and or wind/solar.

Average lake levels need to be increased to enable secure system operation under 100% renewable operation without pumped storage or flexible load

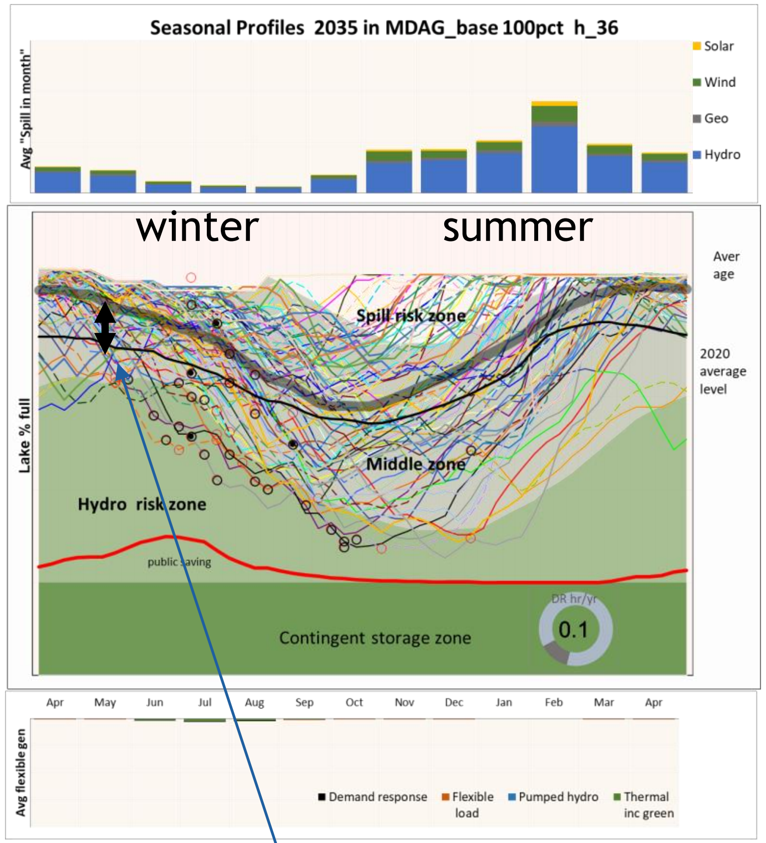
Status Quo System



The 2020 system with around 85% renewable generation, hydro lakes can be operated at lower levels on average.

Thermal backup available for dry years enables sufficient headroom in major lakes to avoid spill during the summer.

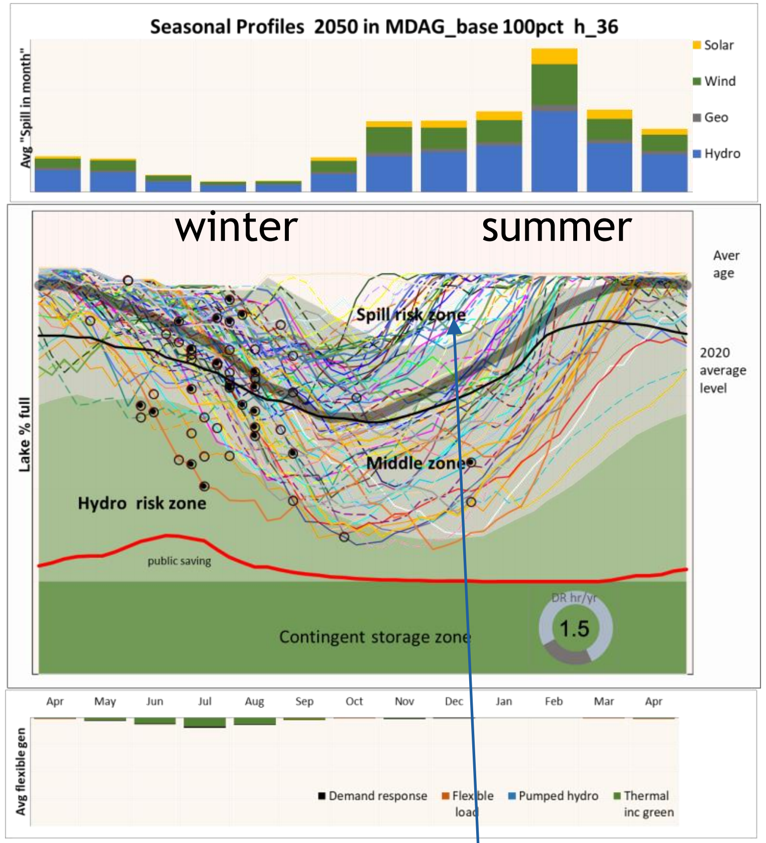
2035 - Reference case - 100% renewable



2020 average lake level shown by black line.

The new average is much higher (600GWh in SI) to enable dry year security at expense of higher spill as a result of reduced head room to absorb lumpy inflows during first half of year.

2050 - Reference case - 100% renewable

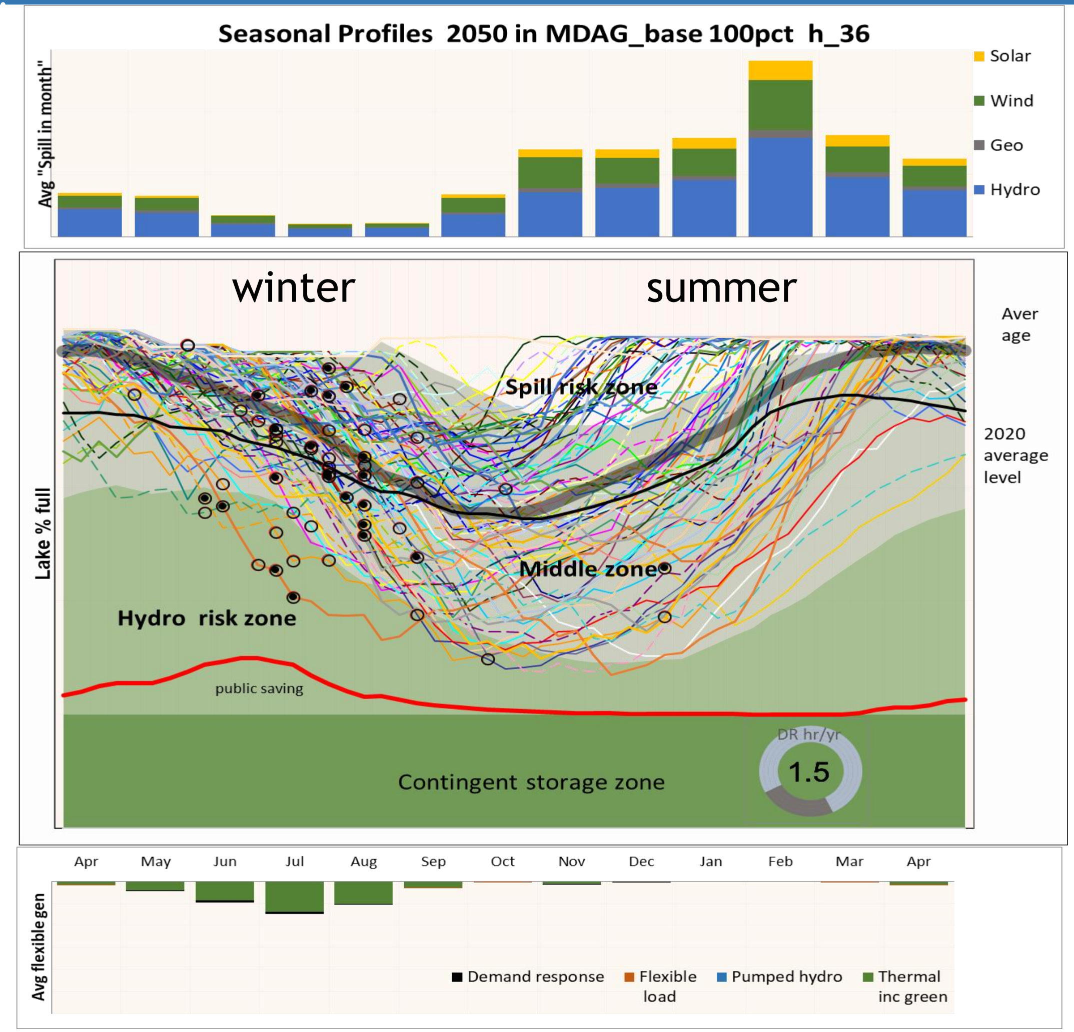


New average in 2050 is similar as the hydro energy risk has not changed significantly.

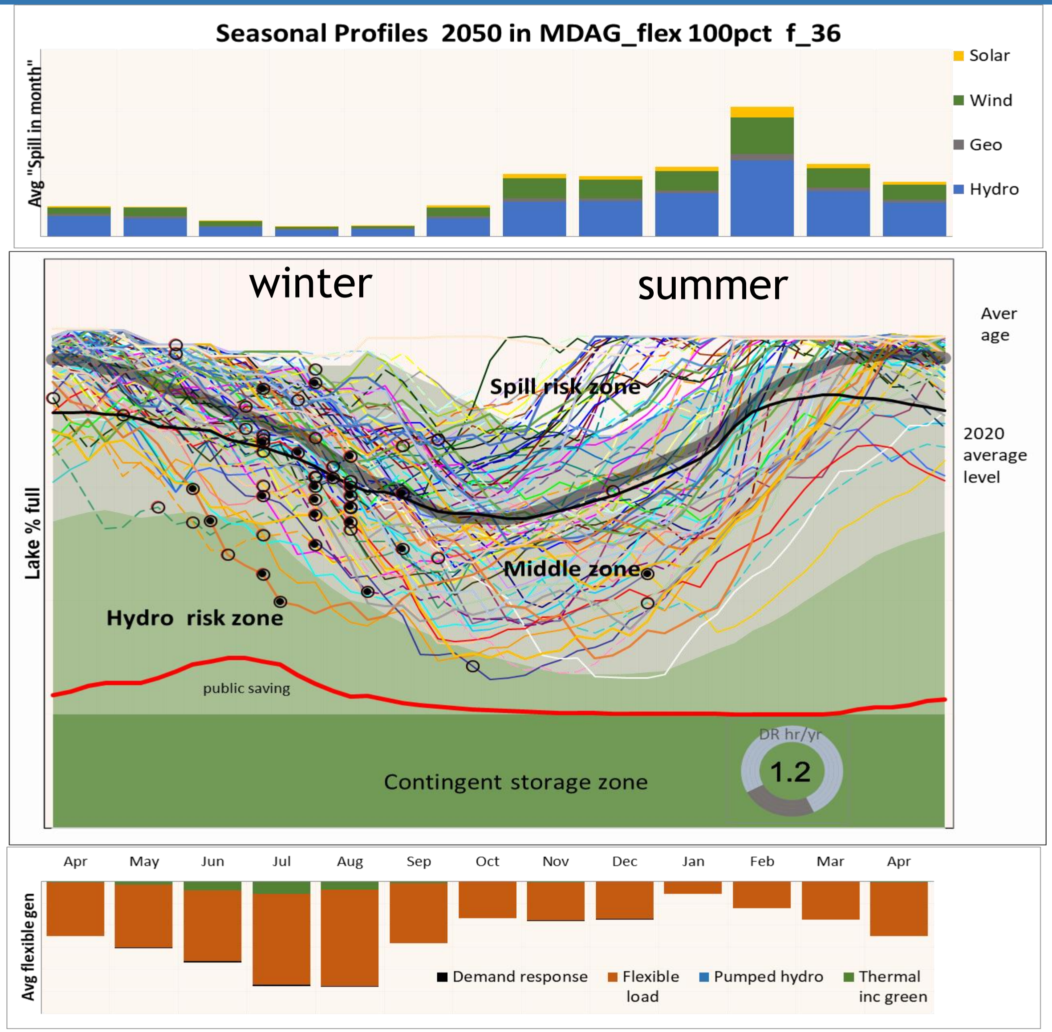
Note the steeply rising trajectories when there are dumps of inflows in Nov to Jan. These cause hydro spill.

A significant level of fully flexible load enables lake levels in spring to be lowered providing headroom to reduce hydro spill somewhat

2050 - Reference case - 100% renewable

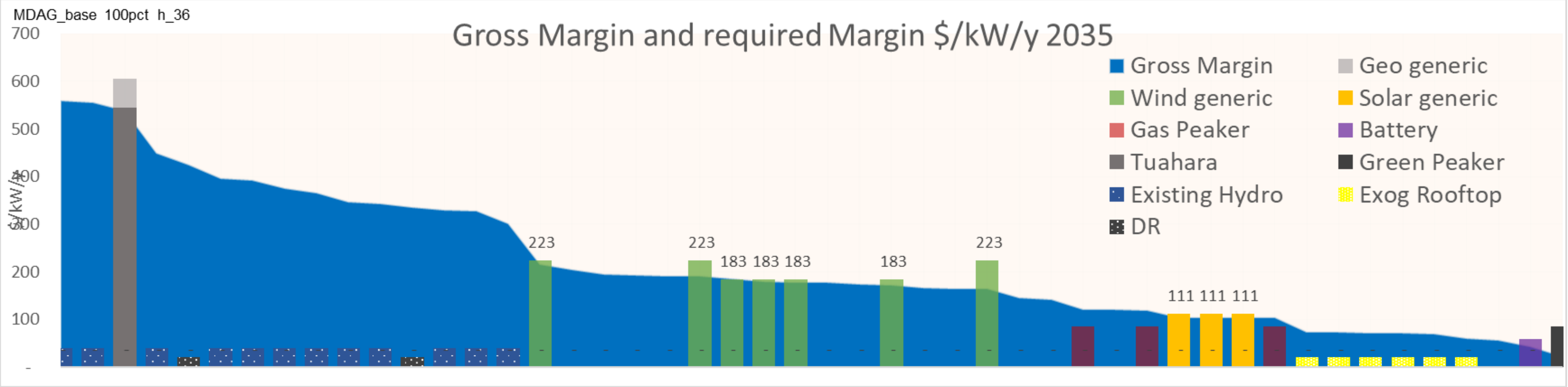


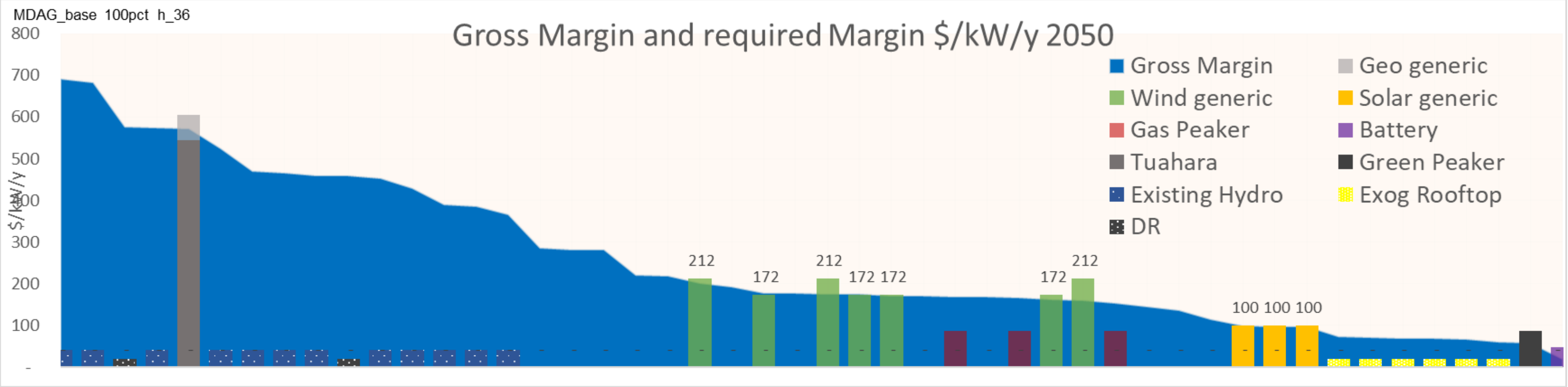
2050 - Reference case - 100% renewable with extra flexible load



APPENDIX 2: NEW ENTRY EQUILIBRIUM

Revenue adequacy in 2035 and 2050 for new plant can be achieved in 100% renewable case scenario





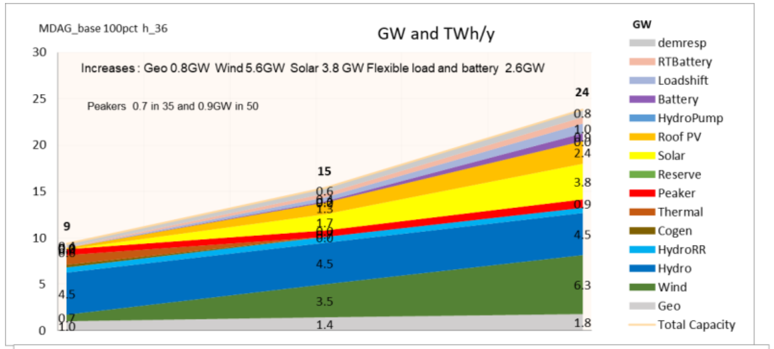
- The chart shows the gross margin in $/kW/yr earned by each type of plant ranked from highest to lowest.
  - This is derived from the full simulation model by week and time zone averaged over 86 weather scenarios.
  - Gross margin = spot revenue minus assumed SRMC.
  - This is calculated for actual new plant and for a notional very small new plant where none is built yet.
- The columns show the gross margin required to cover fixed operating costs and to provide a 7% nominal post tax return on capital.
  - There are several generic wind and solar options with different locations and profiles.
- The methodology involves progressively adding new capacity of the different technology and location until the marginal spot gross margin just covers its fixed costs. This an attempt to mimic competitive new entry by private investors.

APPENDIX 3: SYSTEM CHANGES AND TABLE OF RESULTS

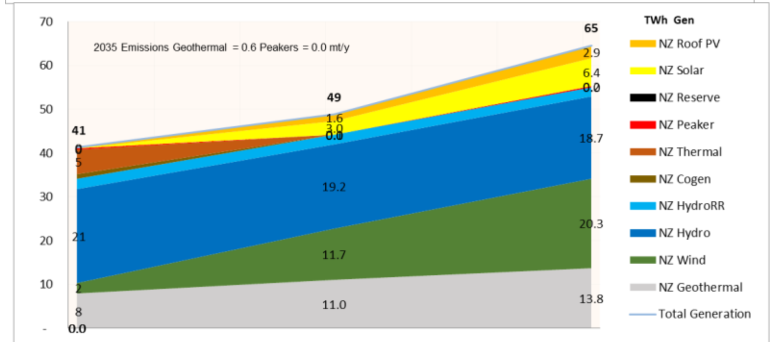
Significant investment in new renewable plant is required to replace existing thermals and to meet load growth – particularly if 100% renewables is required.

100% renewable reference case

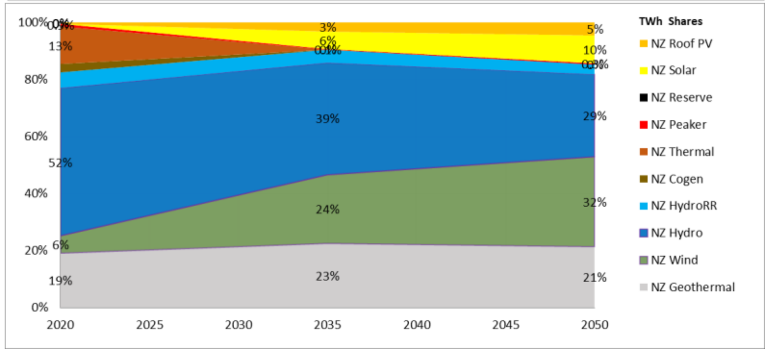
Capacity GW



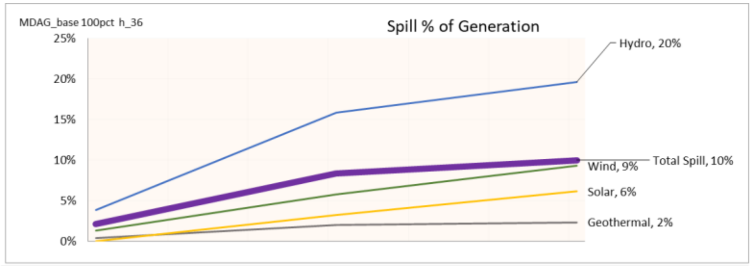
Energy TWh

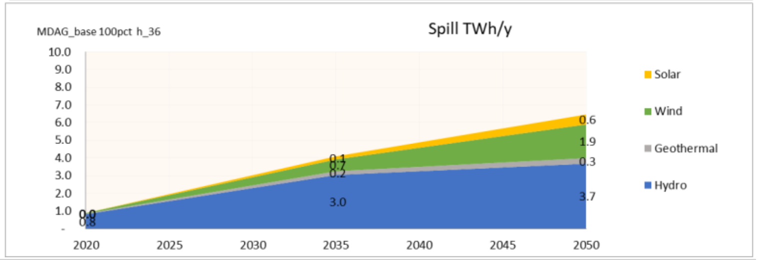


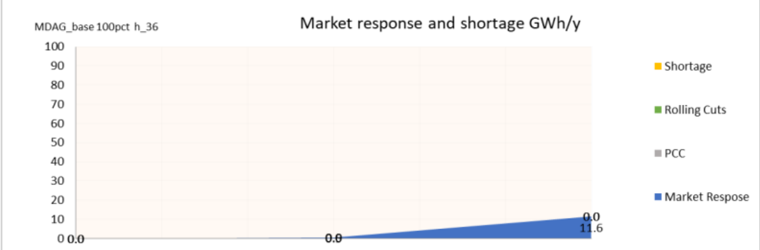
Energy shares %

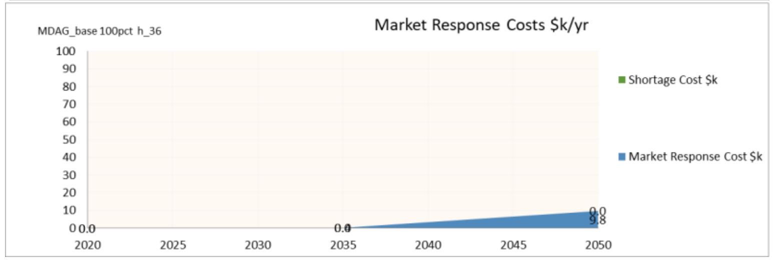


Spill and Shortage



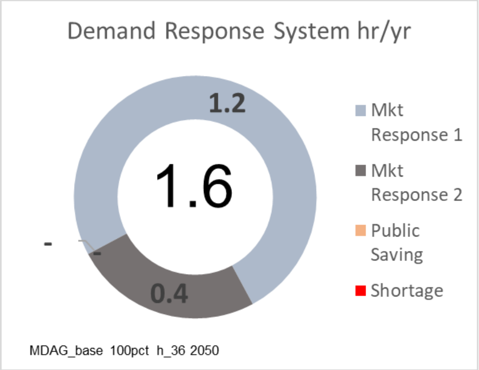






Comments:

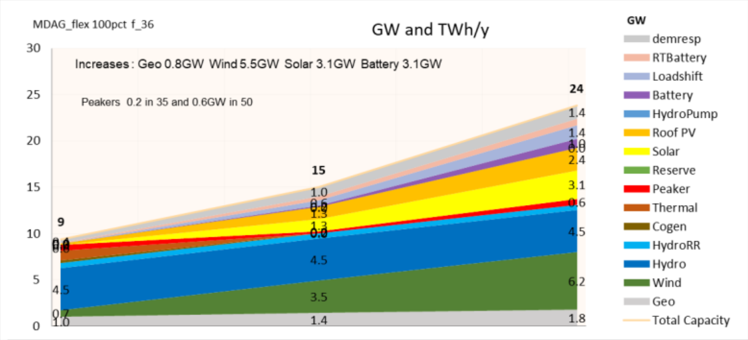
- In the 100% renewable world, 0.9 GW green peakers and 2.6 GW extra battery, flexible demand and load shifting capacity is required.
- There is substantial extra renewable build
  - Wind increases 5.6GW, utility solar increases 3.8GW and geothermal increases 0.8GW.
  - Building additional renewable generation enables security to be met, at the expense of additional "spill".
  - Green peaker emissions are zero, but 0.6mt/y emissions from geothermal continue.
  - Intermittent supply increases from 6% to 47%.



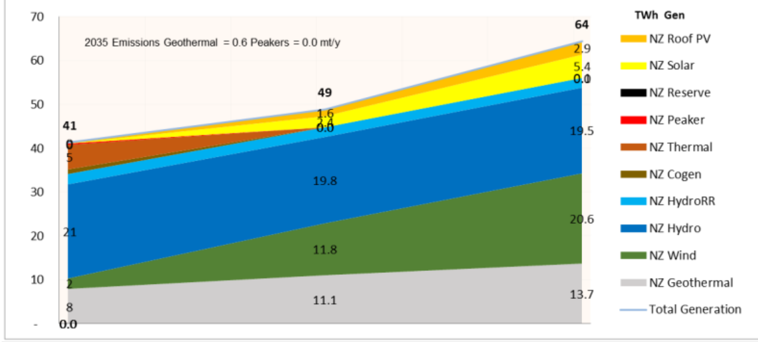
With additional flexible demand it is possible to reduce the investment in new plant while still maintaining system security.

100% renewable with extra demand response

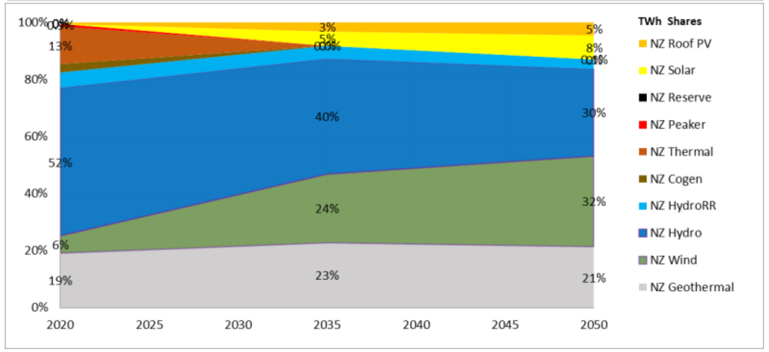
Capacity GW



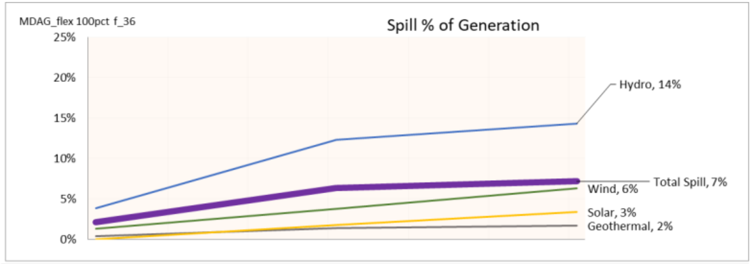
Energy TWh

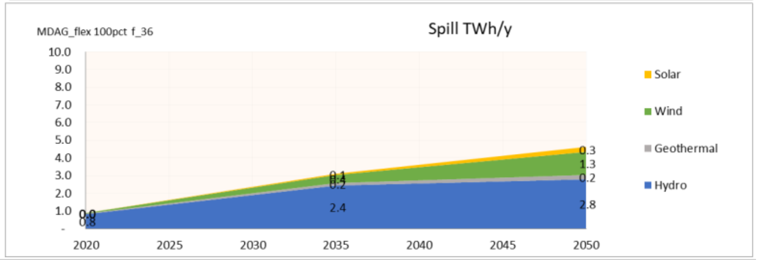


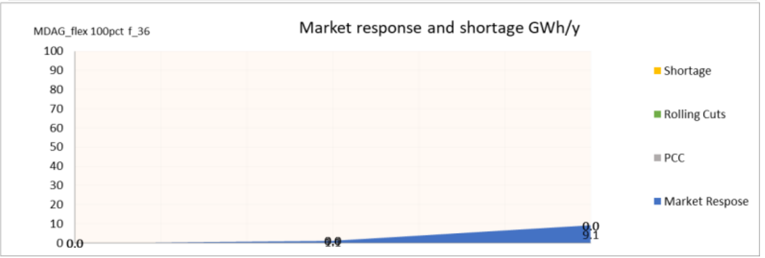
Energy shares %

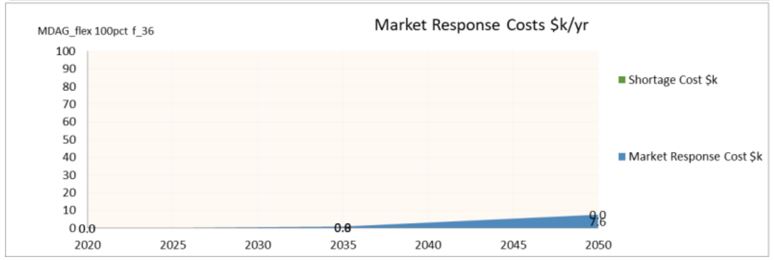


Spill and Shortage









Comments:

- In the enhanced demand flexibility case investment in new renewables can be reduced:
  - Relative to the reference case in 2050:
    - Geothermal is the same
    - Wind is 0.1GW lower
    - Solar is 0.6 GW lower
    - Green peakers are 0.3GW lower
    - Intermittent supply is reduced by around 2% by 2050.

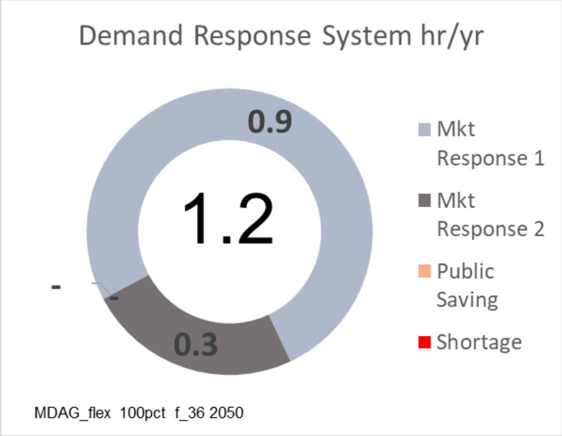


Table of key results – Reference and Enhanced Demand cases

Reference Case

Group	Units	2020	2035	2050	Increase GW/15yrs 2020 to 2035	Increase GW/15yrs 2035 to 2050	Increase MW/yr 2020 to 2035	Increase MW/yr 2035 to 2050
		Reference Demand Case						
Thermal	GW	0.3	0.0	0.0	(0.3)	(0.0)		
Cogen	GW	0.3	0.0	0.0	(0.3)	-		
HydroRR	GW	0.6	0.6	0.6	-	-		
Hydro	GW	4.5	4.5	4.5	-	-		
Geo	GW	1.3	1.4	1.8	0.2	0.4	10	24
Wind	GW	1.3	3.5	6.2	2.2	2.7	150	181
Solar	GW	0.0	1.7	4.0	1.7	2.3	116	151
Rooftop PV	GW	0.4	1.3	2.4	0.9	1.1	63	76
Peaker (Gas - Green)	GW	0.6	0.7	0.9	0.1	0.2	7	13
Grid 5-12hr Battery	GW	0.1	0.2	0.9	0.1	0.8	3	50
Loadshift 5hr (EV charging)	GW	0.0	0.4	1.0	0.4	0.6	26	38
Distributed Battery (3hr) with solar	GW	0.1	0.4	0.7	0.3	0.3	19	23
Market Response (>$700/MWh)	GW	0.4	0.6	0.8	0.2	0.2	11	13
Elastic Flexible Load (>$300/MWh)	GW	0.0	0.0	0.0	-	-		
Total Capacity	GW	9.9	15.4	23.9	5.5	8.5	5.5	3.0
Shiftable load & Batteries	% pk	3%	12%	26%				
Price Elastic Load	% pk	6%	7%	8%				
Total non-hydro grid renewable	GW	2.6	6.7	12.0	4.1	5.3	276	356
Total non_hydro renewable	GW	2.9	8.0	14.5	5.1	6.5	339	432
Total Reserves	GW	1.3	2.3	4.3	1.0	2.1	66	138

Group	Units	2020	2035	2050	Increase GW/15yrs 2020 to 2035	Increase GW/15yrs 2035 to 2050
		Reference Demand Case				
Thermal	TWh	0.3	0.0	0.0	(0.3)	0.0
Cogen	TWh	1.2	0.0	0.0	(1.2)	0.0
HydroRR	TWh	2.2	2.2	2.1	(0.1)	(0.0)
Hydro	TWh	19.8	19.2	18.7	(0.6)	(0.5)
Geothermal	TWh	10.0	11.0	13.8	1.1	2.8
Wind	TWh	4.4	11.7	20.1	7.4	8.4
Solar	TWh	0.0	3.0	6.7	3.0	3.7
Roof PV	TWh	0.4	1.6	2.9	1.1	1.4
Peaker	TWh	0.1	0.1	0.2	(0.1)	0.2
Total Generation	TWh	38.4	48.8	64.5	10.4	15.7
Demand	TWh	35.0	48.5	64.0	13.5	15.5
Max Flexible Load	TWh	0.0	0.0	0.0	-	0.0
Flexible Load not supplied	TWh	0.0	0.0	0.0	(0.0)	0.0
Total Market response/shortage	GWh	0.0	0.5	11.4	0.5	10.9
Total Spill	TWh	2.7	4.1	6.4	1.3	2.4
% Non Renewable	%	3%	0%	0%	(3%)	0%
Pct Intermittent	%	12%	33%	46%	21%	13%
% Wind	%	11%	24%	31%	13%	7%
% Solar	%	1%	9%	15%	8%	5%
Total Emmisons	mt	1.4	1.2	1.5	(0.2)	0.3
Thermal Emissions	mt	0.9	-	-		
Geothermal Emissions	mt	0.5	1.2	1.5	0.7	0.3

Enhanced Demand Response Case

Group	Units	2020	2035	2050	Increase GW/15yrs 2020 to 2035	Increase GW/15yrs 2035 to 2050	Increase MW/yr 2020 to 2035	Increase MW/yr 2035 to 2050
		Enhanced Demand Response						
Thermal	GW	0.3	0.0	0.0	(0.3)	(0.0)		
Cogen	GW	0.3	0.0	0.0	(0.3)	-		
HydroRR	GW	0.6	0.6	0.6	-	-		
Hydro	GW	4.5	4.5	4.5	-	-		
Geo	GW	1.3	1.4	1.8	0.2	0.3	10	23
Wind	GW	1.3	3.5	6.2	2.2	2.7	146	183
Solar	GW	0.0	1.3	3.1	1.3	1.8	90	118
Rooftop PV	GW	0.4	1.3	2.4	0.9	1.1	63	76
Peaker (Gas - Green)	GW	0.6	0.2	0.6	(0.4)	0.4	(26)	27
Grid 5-12hr Battery	GW	0.1	0.2	1.0	0.1	0.9	3	57
Loadshift 5hr (EV charging)	GW	0.0	0.6	1.4	0.6	0.8	38	54
Distributed Battery (3hr) with solar	GW	0.1	0.4	0.7	0.3	0.3	19	23
Market Response (>$700/MWh)	GW	0.4	1.0	1.4	0.6	0.4	37	27
Elastic Flexible Load (>$300/MWh)	GW	0.0	0.4	0.6	0.4	0.2		
Total Capacity	GW	9.9	15.0	23.8	5.1	8.8	5.1	3.7
Shiftable load & Batteries	% pk	3%	14%	31%				
Elastic Load	% pk	6%	17%	20%				
Total Non-hydro grid renewable	GW	2.6	6.3	11.1	3.7	4.9	246	324
Total non_hydro renewable	GW	2.9	7.5	13.5	4.6	6.0	309	400
Total Reserves	GW	1.3	2.3	5.2	1.1	2.8	72	187

Group	Units	2020	2035	2050	Increase GW/15yrs 2020 to 2035	Increase GW/15yrs 2035 to 2050
		Enhanced Demand Response				
Thermal	TWh	0.3	0.0	0.0	(0.3)	0.0
Cogen	TWh	1.2	0.0	0.0	(1.2)	0.0
HydroRR	TWh	2.2	2.2	2.2	(0.0)	(0.0)
Hydro	TWh	19.8	19.8	19.5	0.0	(0.3)
Geothermal	TWh	10.0	11.1	13.7	1.1	2.6
Wind	TWh	4.4	11.8	20.6	7.4	8.8
Solar	TWh	0.0	2.4	5.4	2.4	3.0
Roof PV	TWh	0.4	1.6	2.9	1.1	1.4
Peaker	TWh	0.1	0.0	0.1	(0.1)	0.1
Total Generation	TWh	38.4	48.8	64.3	10.5	15.5
Demand	TWh	35.0	49.4	65.3	14.5	15.9
Max Flexible Load	TWh	0.0	3.5	5.3	3.5	1.8
Flexible Load not supplied	TWh	0.0	0.9	1.4	0.9	0.5
Total Market response/shortage	GWh	0.0	1.7	9.1	1.7	7.4
Total Spill	TWh	2.7	3.1	4.6	0.3	1.5
% Non Renewable	%	3%	0%	0%	(3%)	0%
Pct Intermittent	%	12%	32%	45%	20%	13%
% Wind	%	11%	24%	32%	13%	8%
% Solar	%	1%	8%	13%	7%	5%
Total Emmisons	mt	1.4	1.2	1.5	(0.1)	0.3
Thermal Emissions	mt	0.9	-	-		
Geothermal Emissions	mt	0.5	1.2	1.5	0.7	0.3

Table of key results – low demand response case

Low demand Case

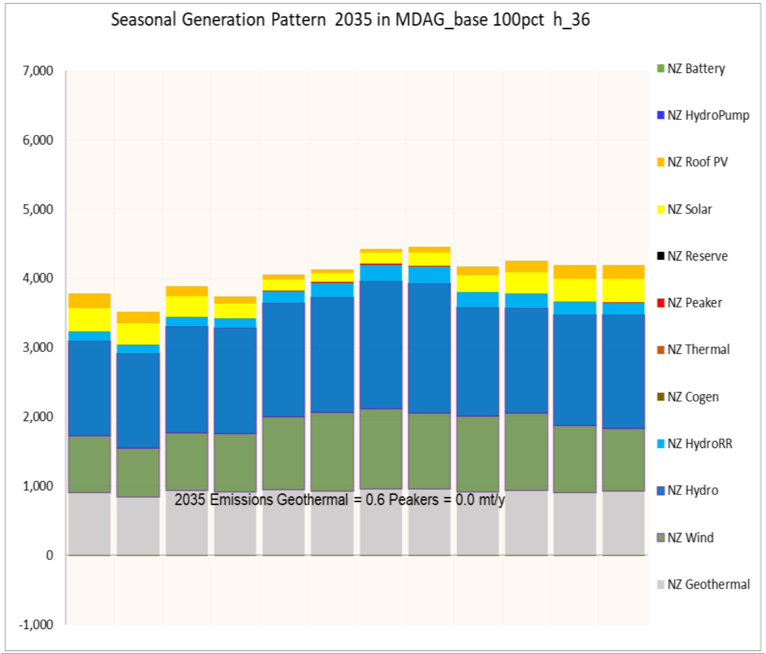
Group	Units	2020	2035	2050	Increase GW/15yrs 2020 to 2035	Increase GW/15yrs 2035 to 2050	Increase MW/yr 2020 to 2035	Increase MW/yr 2035 to 2050
		Low Demand Response Case						
Thermal	GW	0.3	0.0	0.0	(0.3)	(0.0)		
Cogen	GW	0.3	0.0	0.0	(0.3)	-		
HydroRR	GW	0.6	0.6	0.6	-	-		
Hydro	GW	4.5	4.5	4.5	-	-		
Geo	GW	1.3	1.4	1.8	0.2	0.4	10	24
Wind	GW	1.3	3.7	6.4	2.4	2.7	160	181
Solar	GW	0.0	1.5	3.8	1.5	2.3	99	151
Rooftop PV	GW	0.4	1.3	2.4	0.9	1.1	63	76
Peaker (Gas - Green)	GW	0.6	0.3	0.9	(0.3)	0.6	(20)	40
Grid 5-12hr Battery	GW	0.1	0.3	1.3	0.2	1.0	13	67
Loadshift 5hr (EV charging)	GW	0.0	0.2	0.5	0.2	0.3	12	19
Distributed Battery (3hr) with solar	GW	0.1	0.2	0.4	0.1	0.2	6	11
Market Response (>$700/MWh)	GW	0.4	0.4	0.6	(0.0)	0.1	(1)	9
Elastic Flexible Load (>$300/MWh)	GW	0.0	0.0	0.0	-	-		
Total Capacity	GW	9.9	14.4	23.1	4.6	8.7	4.6	4.1
Shiftable load & Batteries	% pk	3%	9%	21%				
Elastic Load	% pk	6%	5%	5%				
Total Non-hydro grid renewable	GW	2.6	6.6	11.9	4.0	5.3	269	356
Total non_hydro renewable	GW	2.9	7.9	14.4	5.0	6.5	332	433
Total Reserves	GW	1.3	1.4	3.6	0.2	2.2	11	146

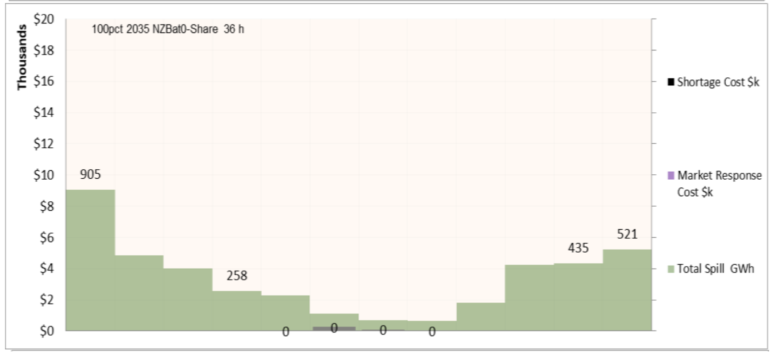
Group	Units	2020	2035	2050	Increase GW/15yrs 2020 to 2035	Increase GW/15yrs 2035 to 2050
		Low Demand Response Case				
Thermal	TWh	0.3	0.0	0.0	(0.3)	0.0
Cogen	TWh	1.2	0.0	0.0	(1.2)	0.0
HydroRR	TWh	2.2	2.2	2.1	(0.1)	(0.0)
Hydro	TWh	19.8	19.2	18.7	(0.6)	(0.5)
Geothermal	TWh	10.0	11.0	13.8	1.0	2.8
Wind	TWh	4.4	12.2	20.5	7.9	8.3
Solar	TWh	0.0	2.6	6.3	2.6	3.7
Roof PV	TWh	0.4	1.6	2.9	1.1	1.4
Peaker	TWh	0.1	0.0	0.2	(0.1)	0.2
Total Generation	TWh	38.4	48.8	64.6	10.5	15.8
Demand	TWh	35.0	48.5	64.0	13.5	15.5
Max Flexible Load	TWh	0.0	0.0	0.0	-	0.0
Flexible Load not supplied	TWh	0.0	0.0	0.0	(0.0)	0.0
Total Market response/shortage	GWh	0.0	4.7	11.0	4.7	6.3
Total Spill	TWh	2.7	4.1	6.5	1.4	2.3
% Non Renewable	%	3%	0%	0%	(3%)	0%
Pct Intermittent	%	12%	34%	46%	21%	12%
% Wind	%	11%	25%	32%	14%	7%
% Solar	%	1%	9%	14%	7%	6%
Total Emmisons	mt	1.4	1.2	1.5	(0.2)	0.3
Thermal Emissions	mt	0.9	-	-		
Geothermal Emissions	mt	0.5	1.2	1.5	0.7	0.3

APPENDIX 4: SEASONAL AND WITHIN DAY GENERATION PROFILES

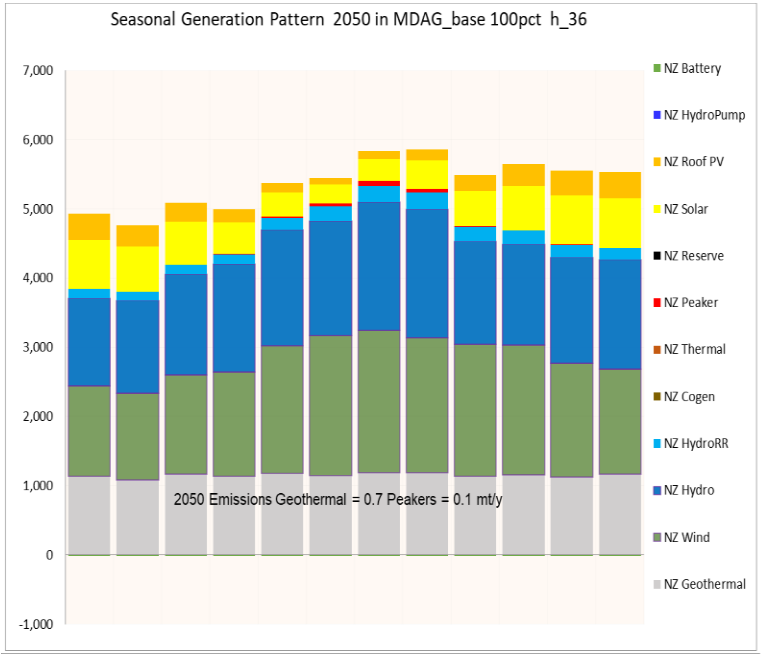
The seasonal pattern of generation is expected to change under 100% renewable reference case

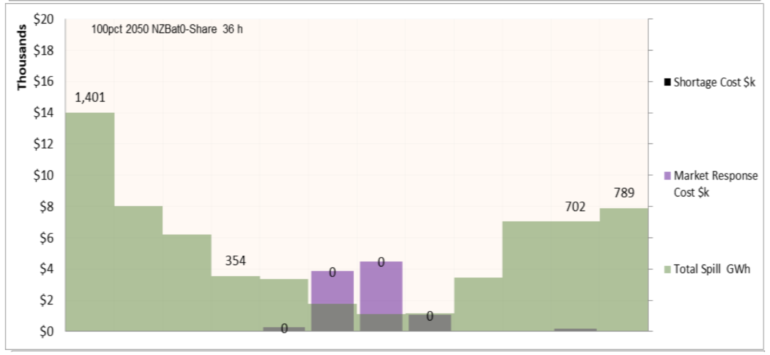
2035 - mean MW generation over each month averaged over 86 weather years





2050



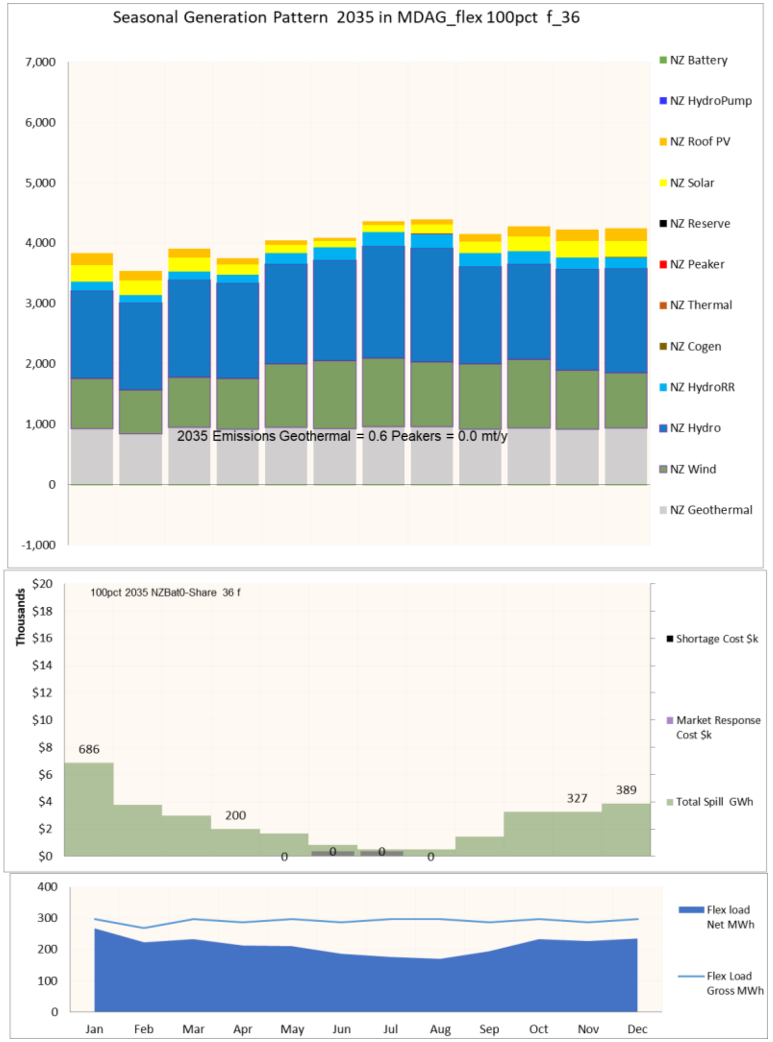


Commentary

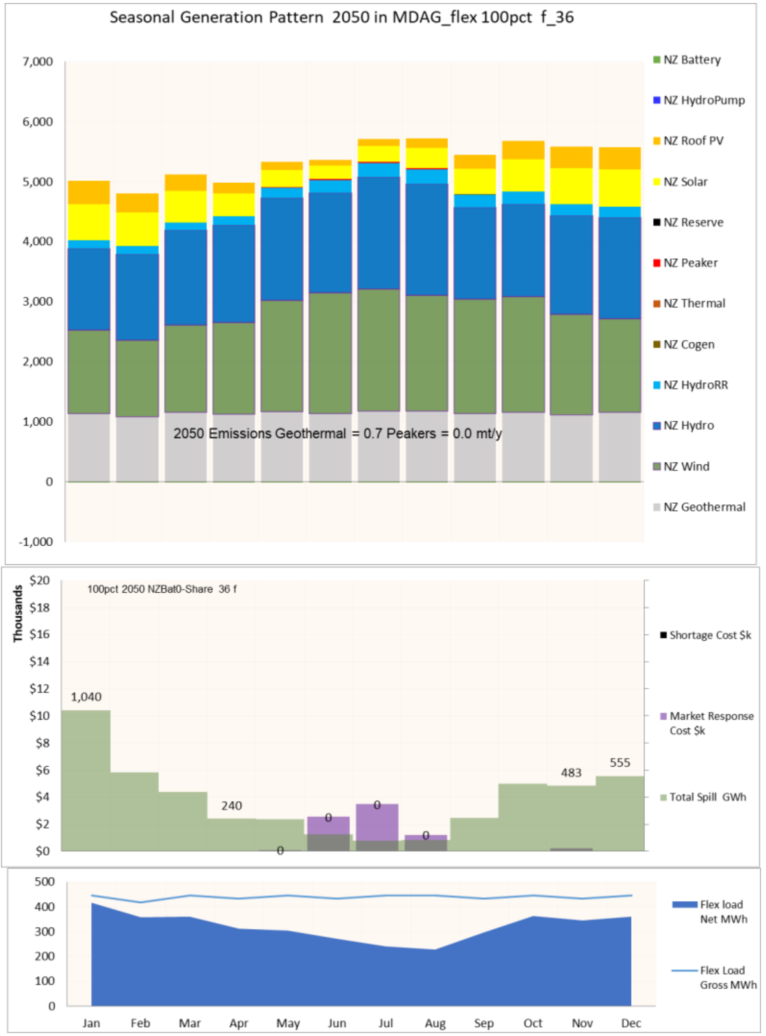
- Note the impact of rooftop and utility scale solar on the seasonal components.
- The chart shows actual generation from wind. The apparent seasonal shape, reflects expected levels of wind being dispatched off during high wind/solar/hydro periods in the summer.
- Spill is greatest in summer when hydro lakes are being filled prior to winter, and negligible over winter when lakes are being used to meet demand.
- Shortage is greatest in winter because there is limited capacity from the hydro system to cover longer periods of low wind. These must be met from a mix of green peakers and demand response. There is also a risk of shortage in the most extreme weather conditions.

The increased seasonal pattern of generation is reduced by greater flexible load reductions during the winter compared with the reference case scenario.

2035 - mean MW generation over each month averaged over 86 weather years (Enhanced Demand Scenario)



2050 (Enhanced Demand Scenario)



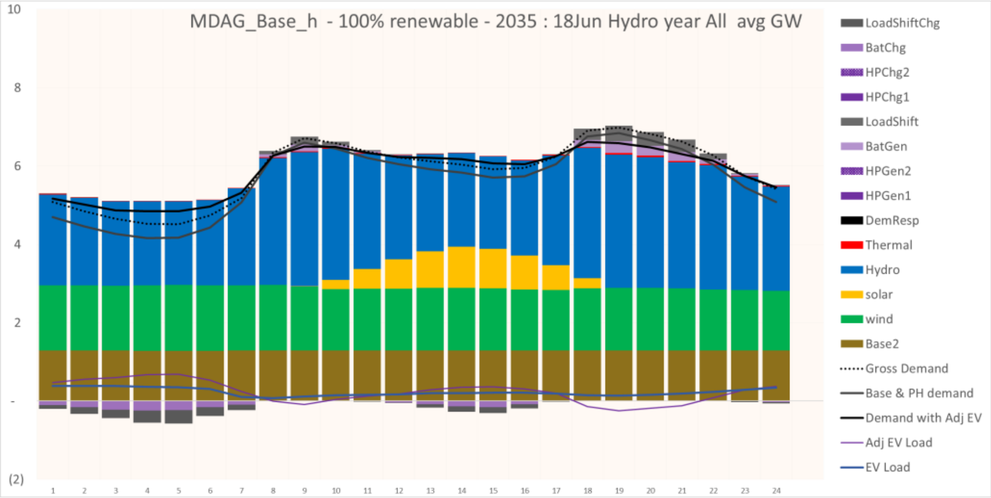
Commentary

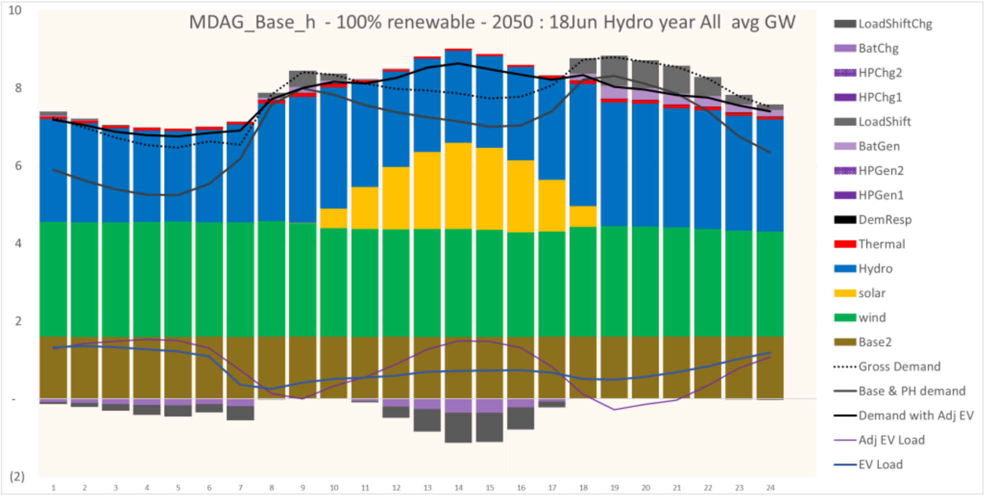
- Note the impact of rooftop and utility scale solar on the seasonal components.
- The chart shows actual generation from wind. The apparent seasonal shape, reflects expected levels of wind being dispatched off during high wind/solar/hydro periods in the summer.
- Spill is greatest in summer when hydro lakes are being filled prior to winter, and negligible over winter when lakes are being used to meet demand.
- Flexible load is reduced more significantly in winter as prices are higher then.
- Shortage is greatest in winter because there is limited capacity from the hydro system to cover longer periods of low wind. These must be met from a mix of green peakers and demand response. There is also a risk of shortage in the most extreme weather conditions.

The average daily generation pattern changes under 100% renewables reference case

2035	2050

A typical winter week

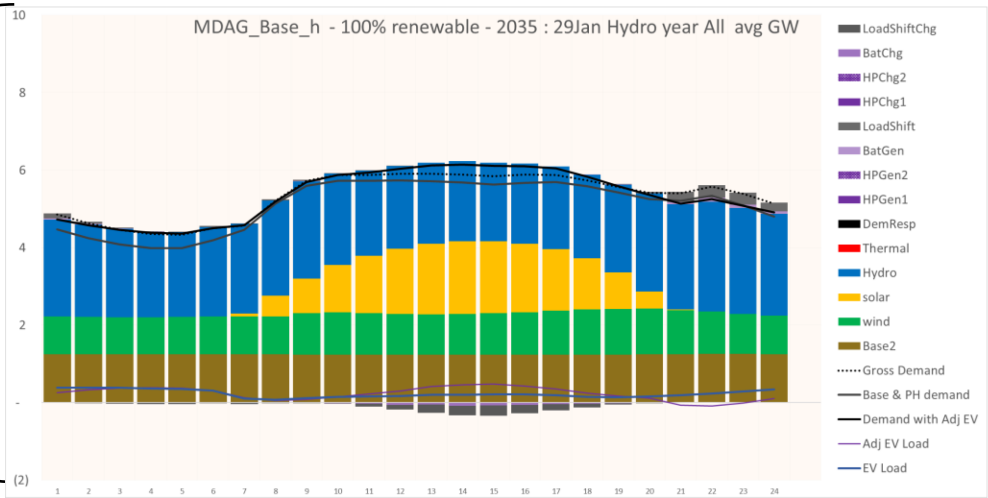


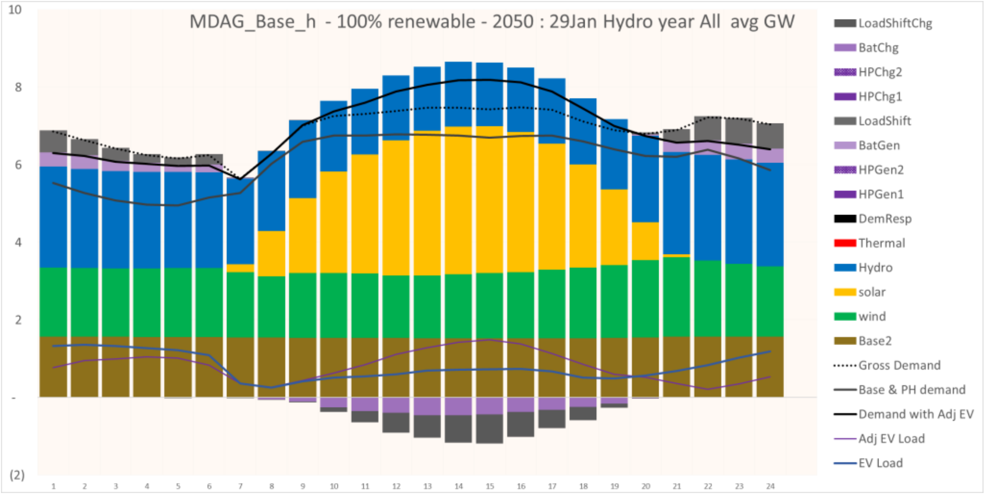


The within-day patterns of generation supply are heavily influenced by increasing solar and use of batteries and EV load shifting.

Chart shows average for a typical work day in early June.

A typical Summer week





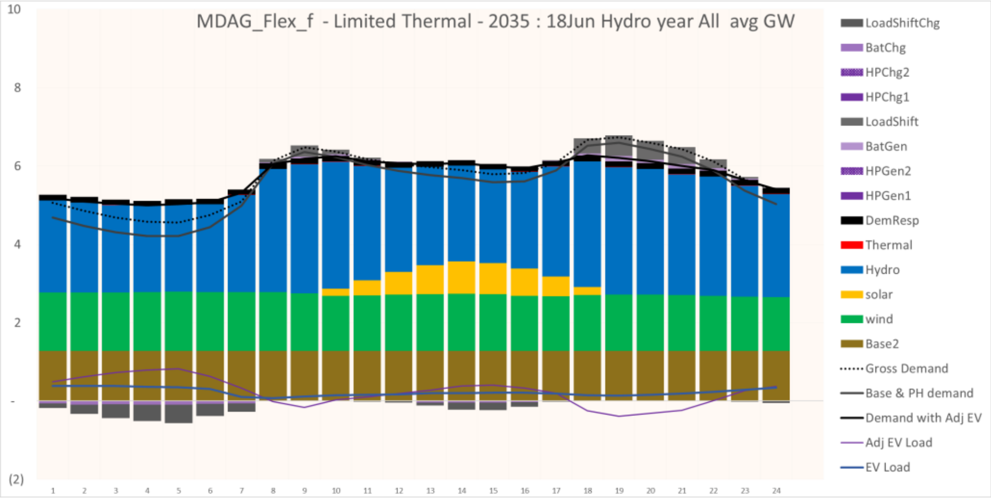
The effect of solar is greatest in the summer as expected.

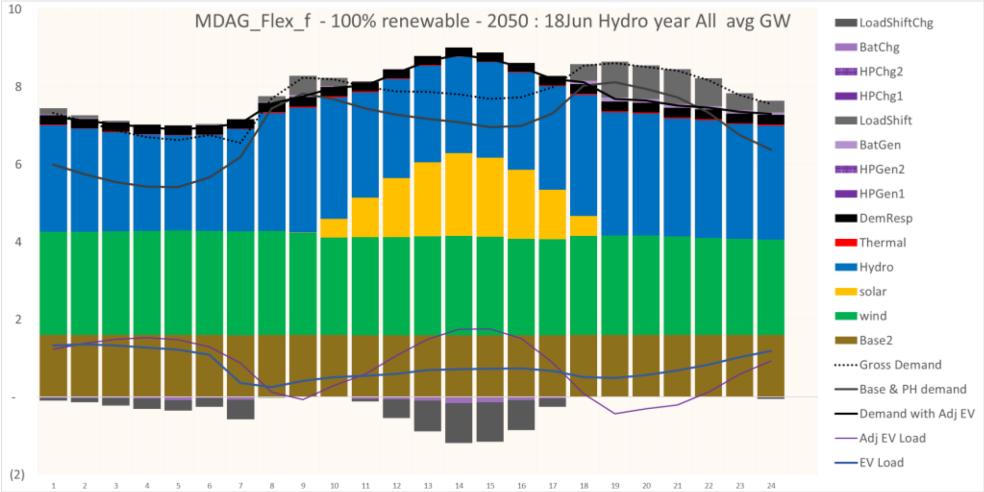
Chart shows average for a typical work day in late January.

The average daily generation pattern changes under 100% renewables with extra flexible load

2035 - Enhanced demand response	2050 Enhanced demand response

A typical winter week



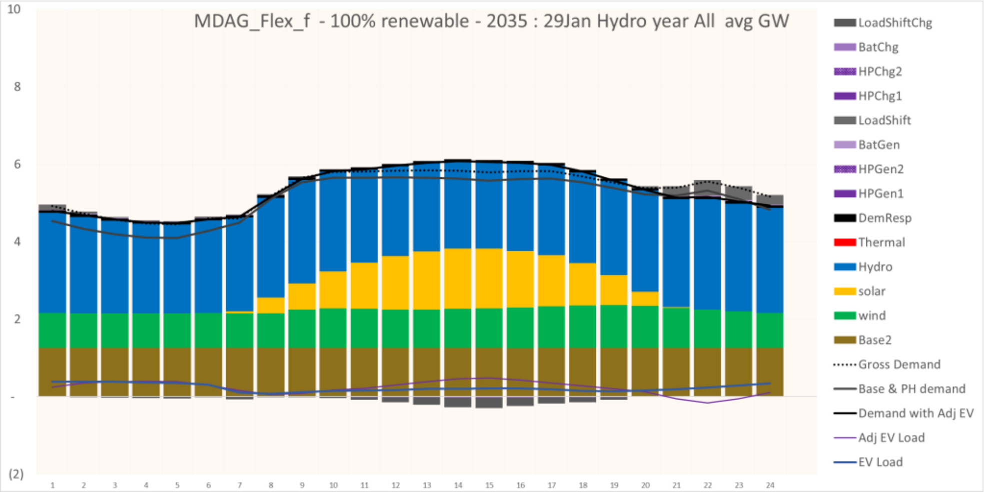


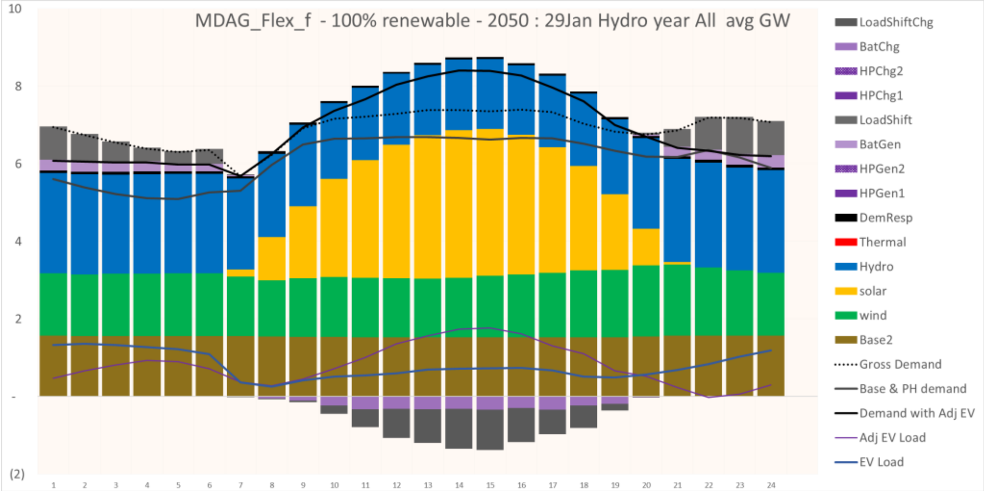
The within-day patterns of generation supply are heavily influenced by increasing solar and use of batteries and EV load shifting.

Flexible load is backed off more in the winter than the summer.

Extra load shifting capacity enables fully flexible load reductions to be spread out over the day to a degree.

A typical Summer week





Extra load shifting enables vehicle charging to be shifted into the middle of the day in summer.

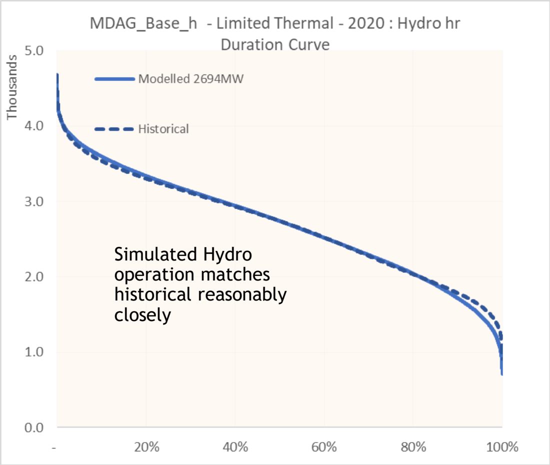
APPENDIX 5: GENERATION, RESIDUAL DEMAND AND FLOW DURATION CURVES

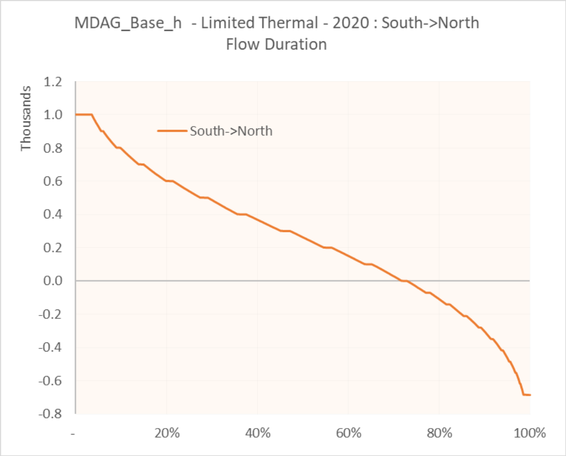
Benchmarking generation duration curves and load/residual load duration curves in 2020

concept consulting JC2

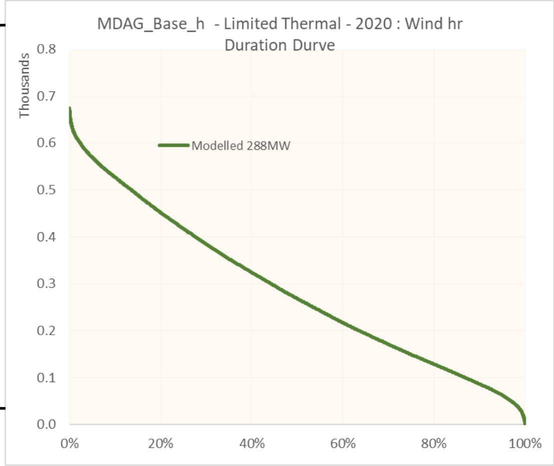
2020 Benchmark Generation Duration

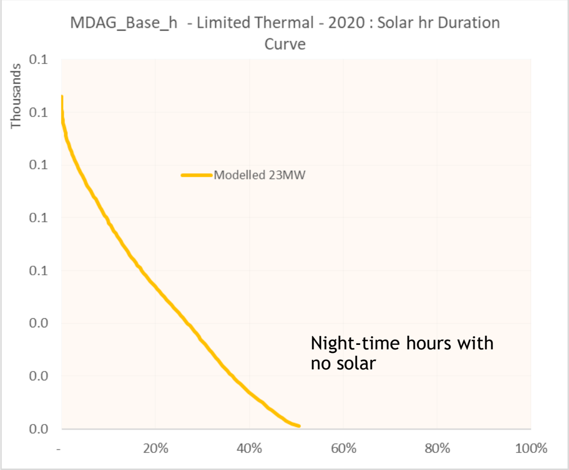
GW





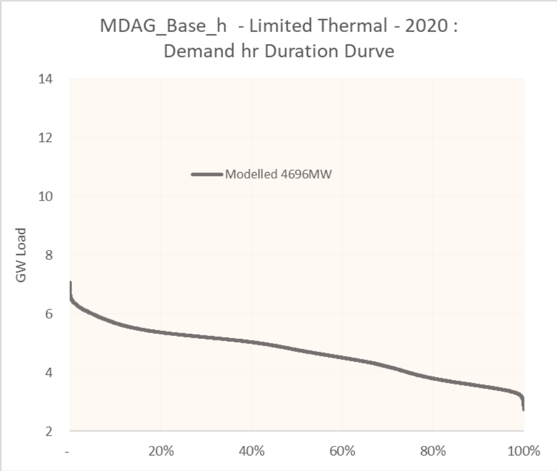
GW

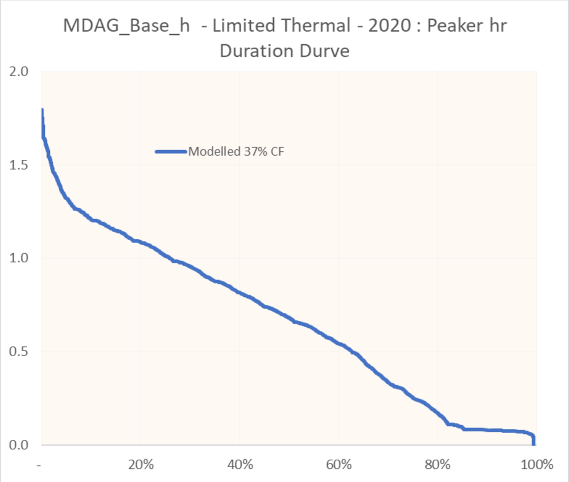


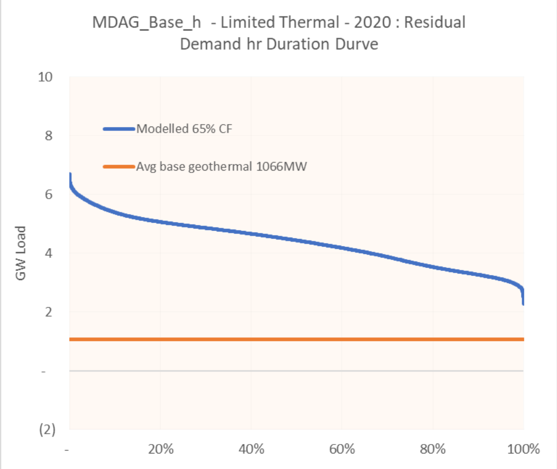


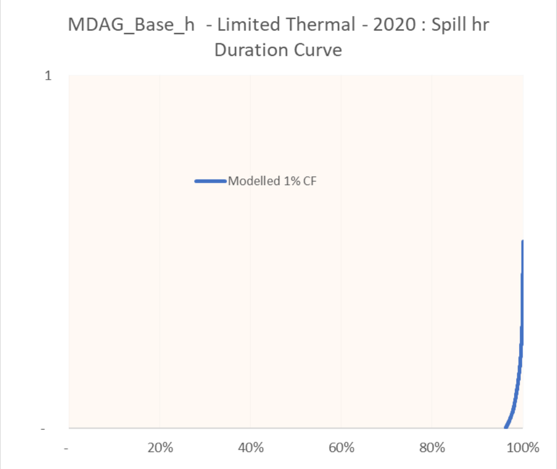
Cumulative % of hours ranked from high to low generation.

2020 Benchmark Load and Residual Load Duration curves







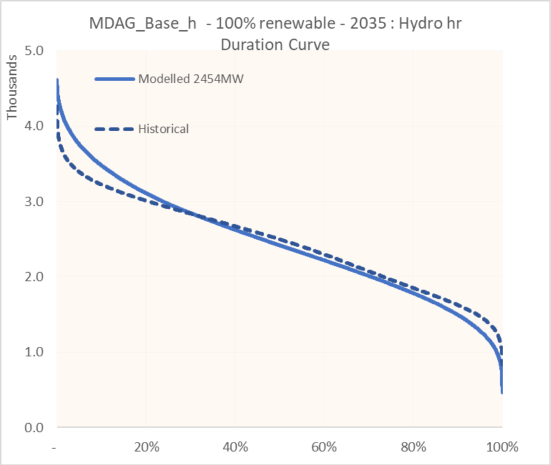


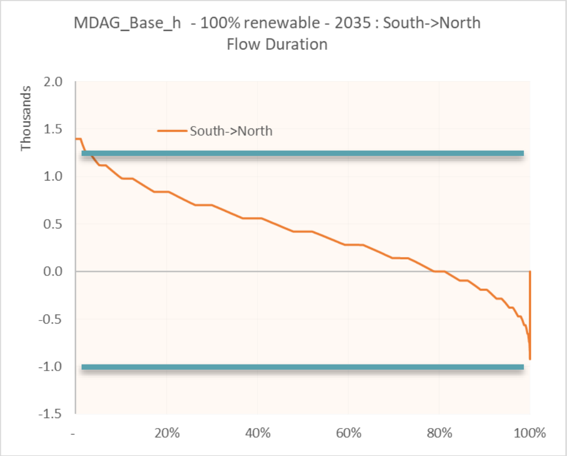
Only spill is ranked from low to high

Generation duration curves under 100% renewables

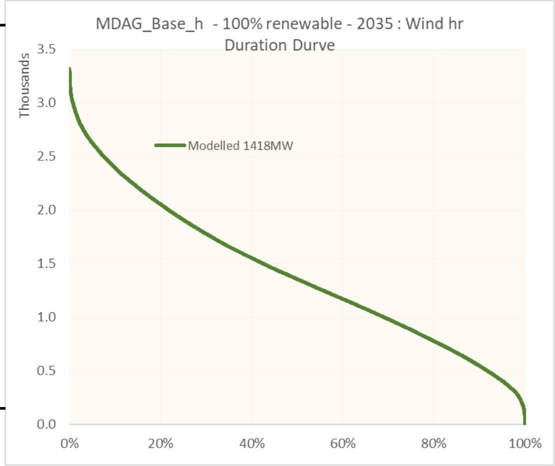
2035

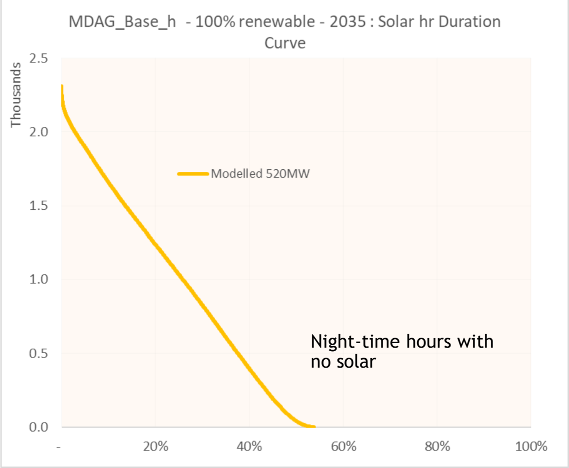
GW





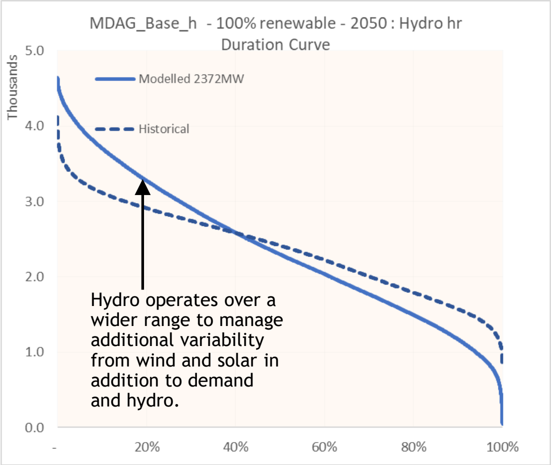
GW

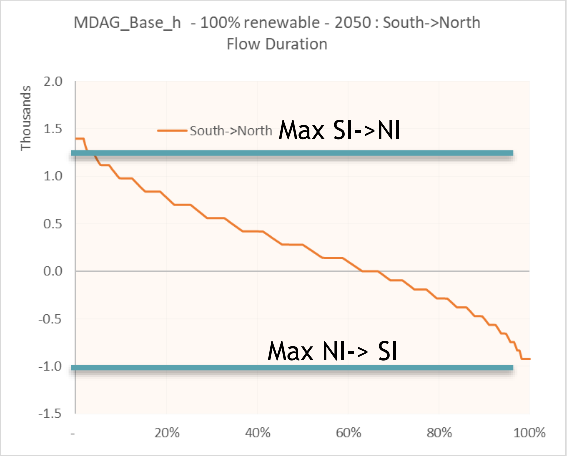


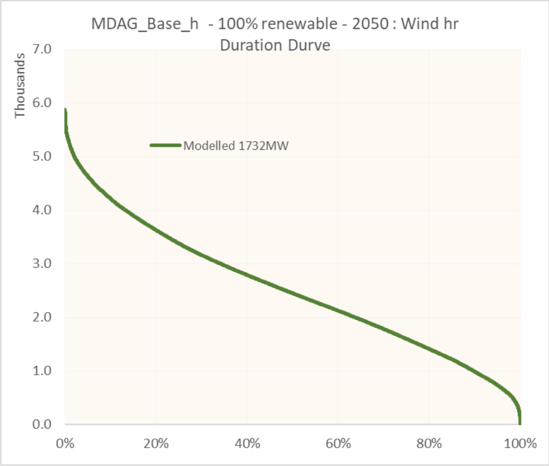


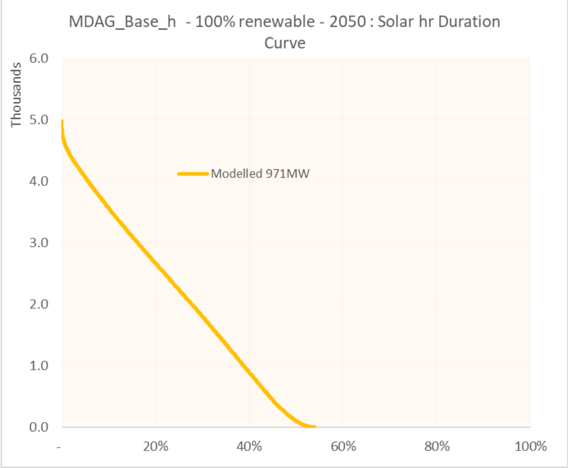
Cumulative % of hours ranked from high to low generation.

2050

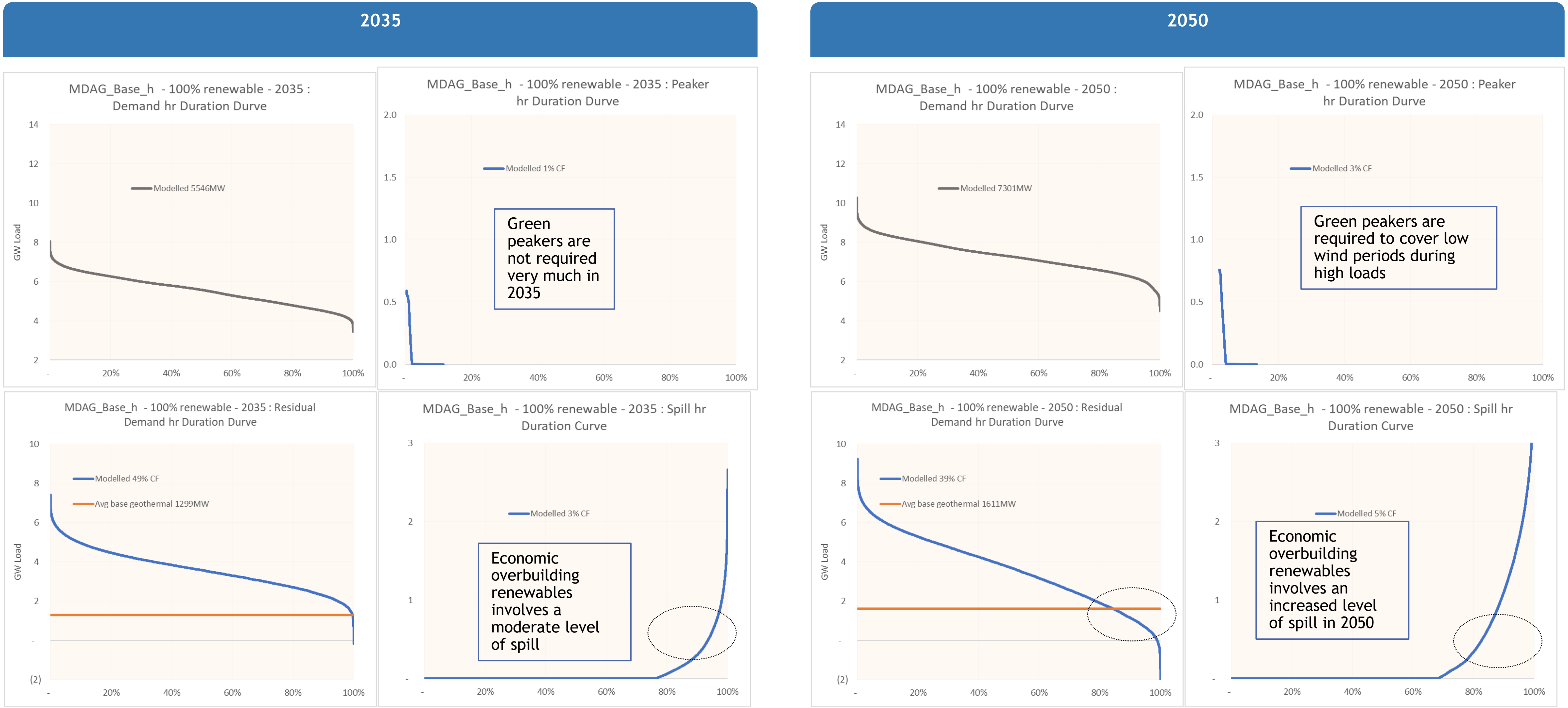








Load and Residual Load Duration Curves under 100% renewables



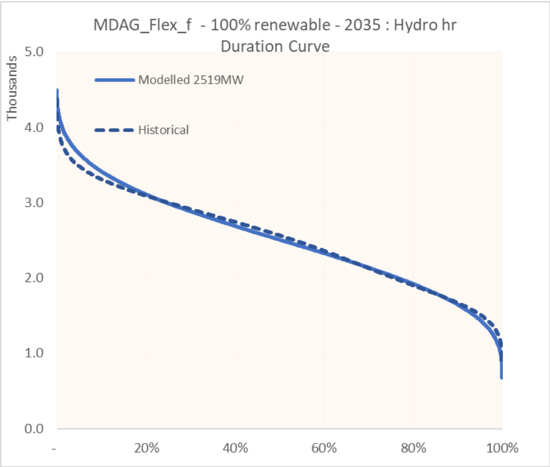
Notes: Residual Demand is demand minus potential generation from solar and wind generation. This measure highlights the risk of “spill” as the RLDC falls below minimum levels of other generation. The chart shows baseload geothermal, but there is also minimum hydro generation from resource constraints and hydro tributaries which will also contribute to the risk of “spill”.

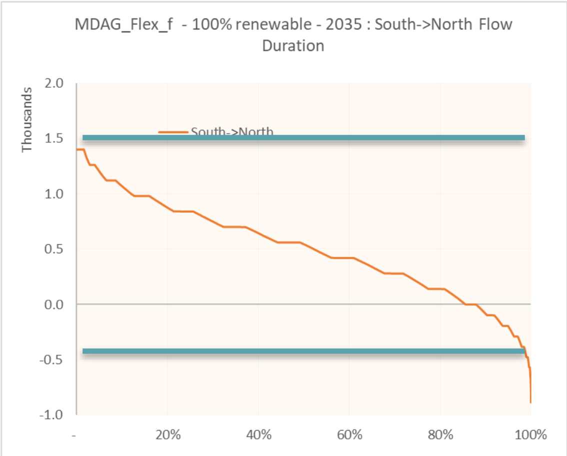
Generation duration curves under 100% renewables- with demand extra flexible demand

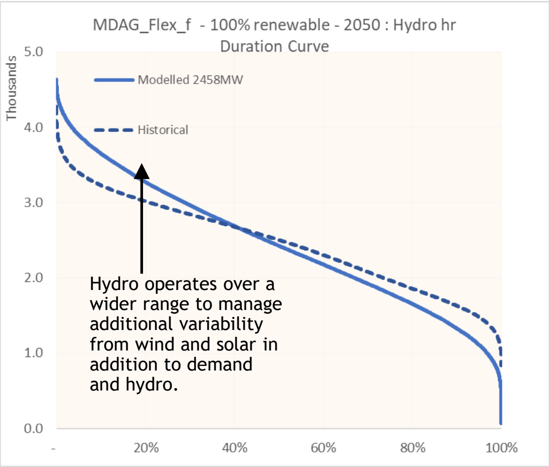
2035

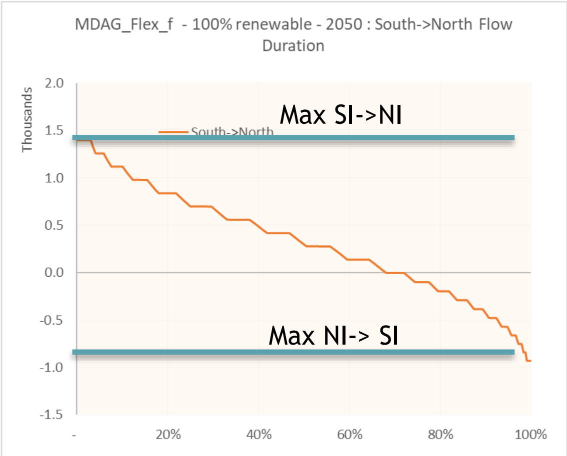
2050

GW

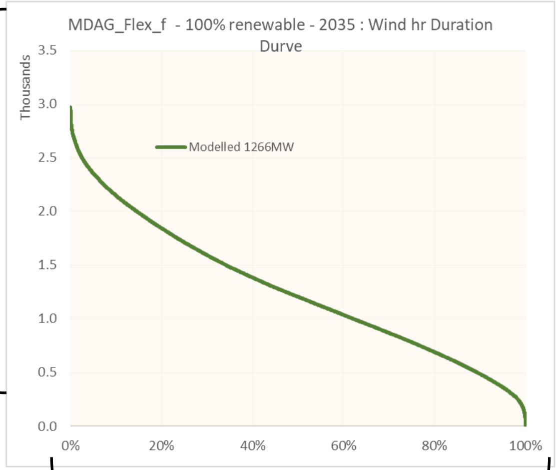


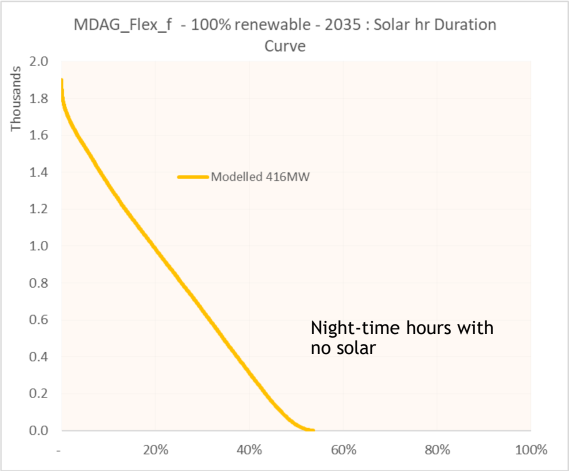


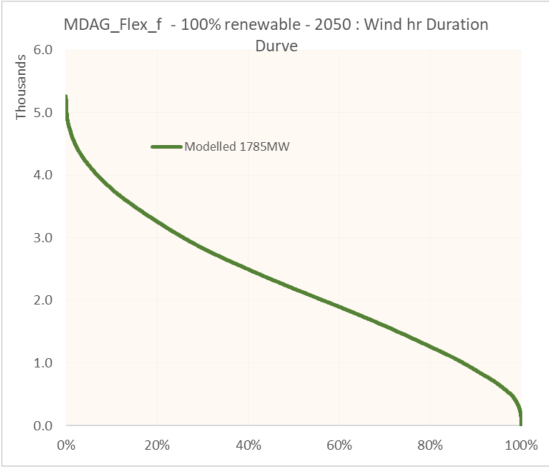


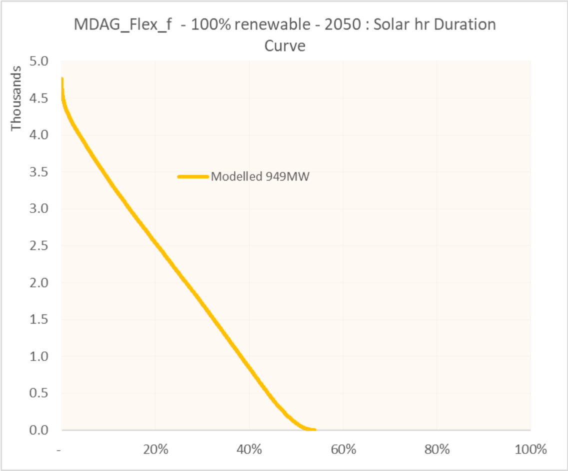


GW





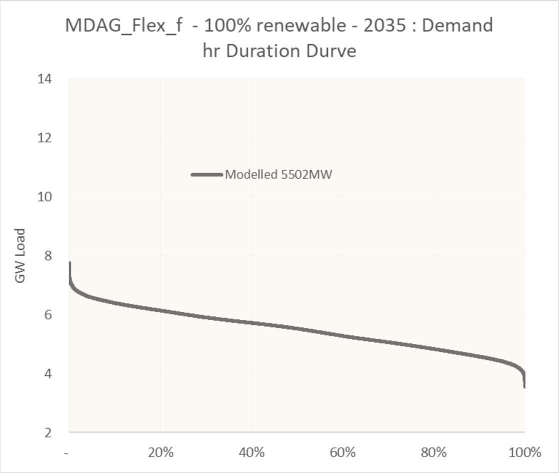


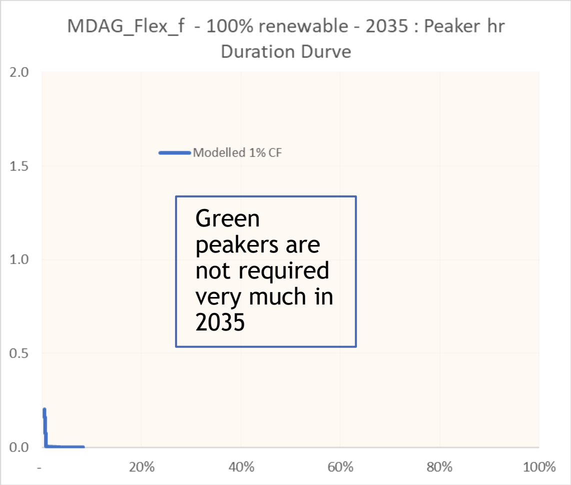


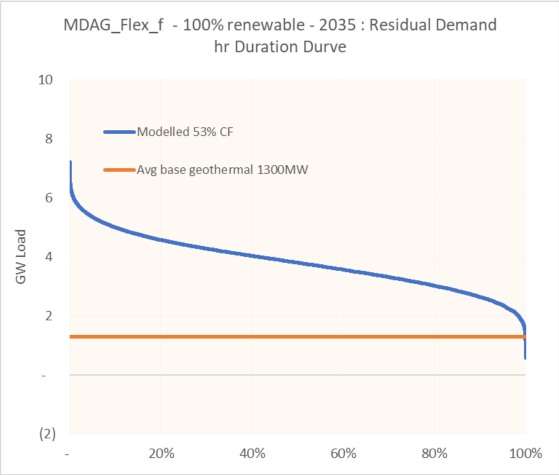
Cumulative % of hours ranked from high to low generation.

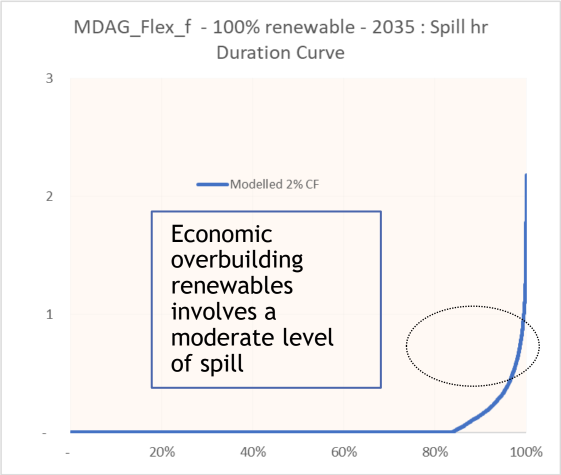
Load and Residual Load Duration Curves under 100% renewables – with extra flexible demand

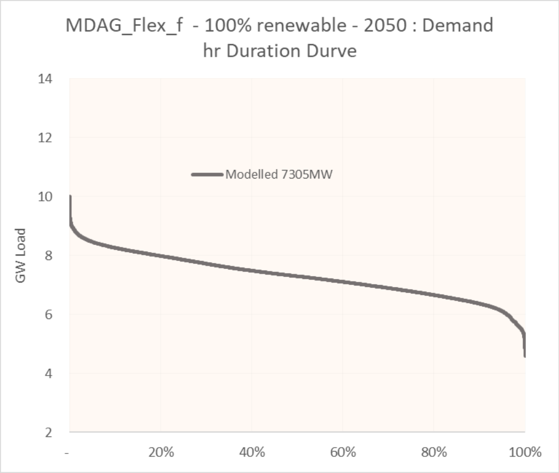
2035	2050

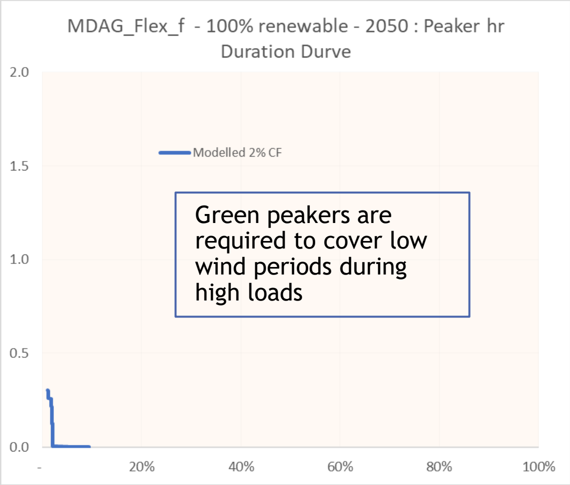


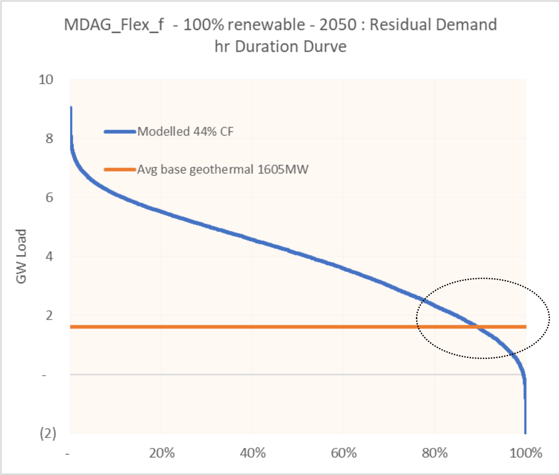


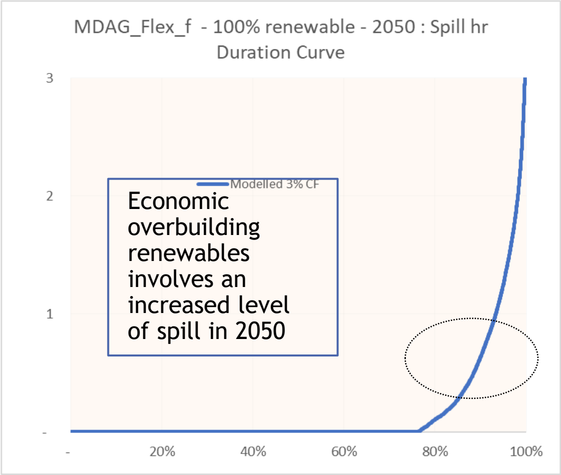










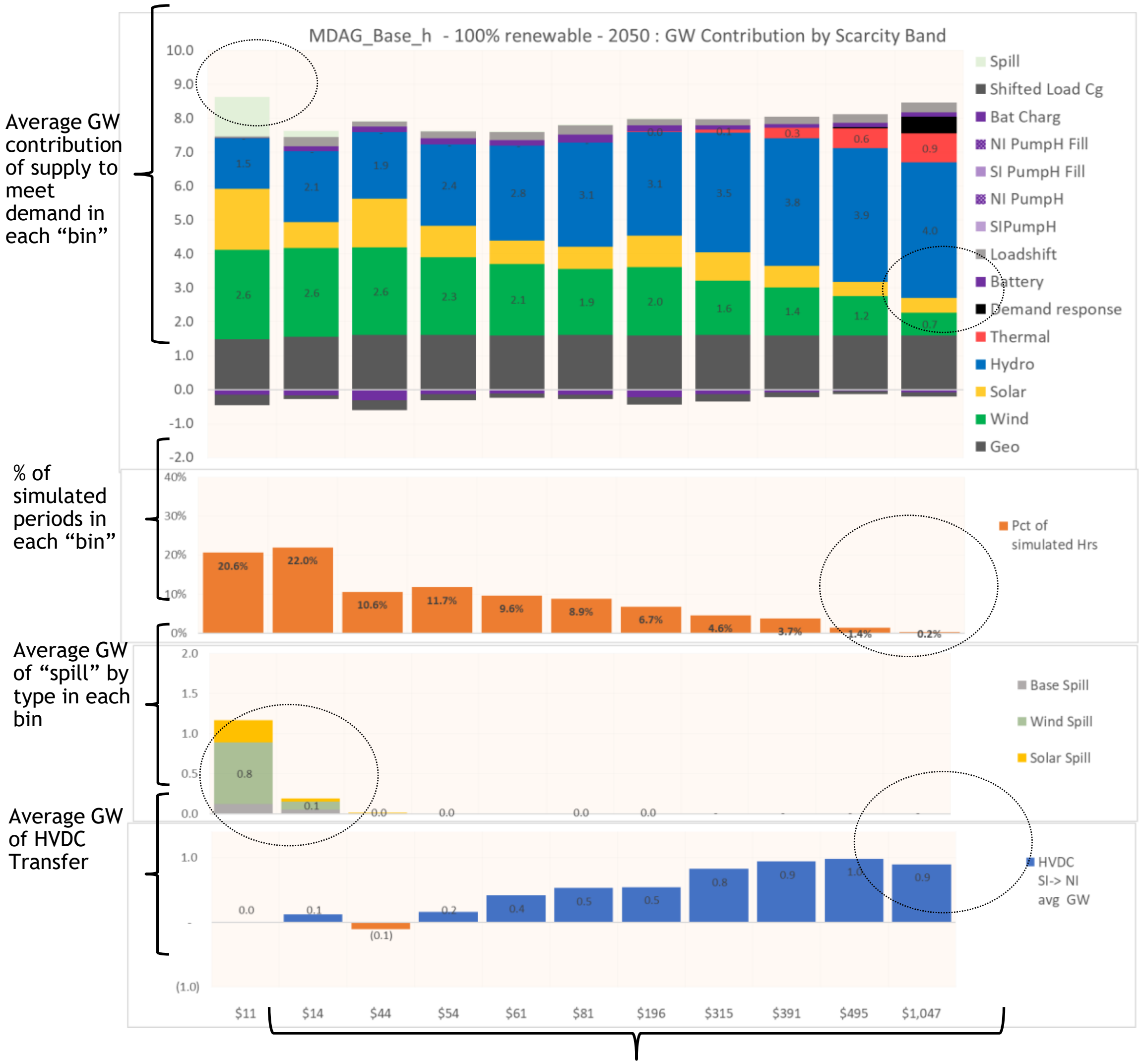


Notes: Residual Demand is demand minus potential generation from solar and wind generation. This measure highlights the risk of "spill" as the RLDC falls below minimum levels of other generation. The chart shows baseload geothermal, but there is also minimum hydro generation from resource constraints and hydro tributaries which will also contribute to the risk of "spill".

APPENDIX 6: GENERATION CONTRIBUTION BY TYPE

Contribution of renewables to periods of surplus and scarcity – chart explanation

Illustrative Chart - 100% renewable in 2050



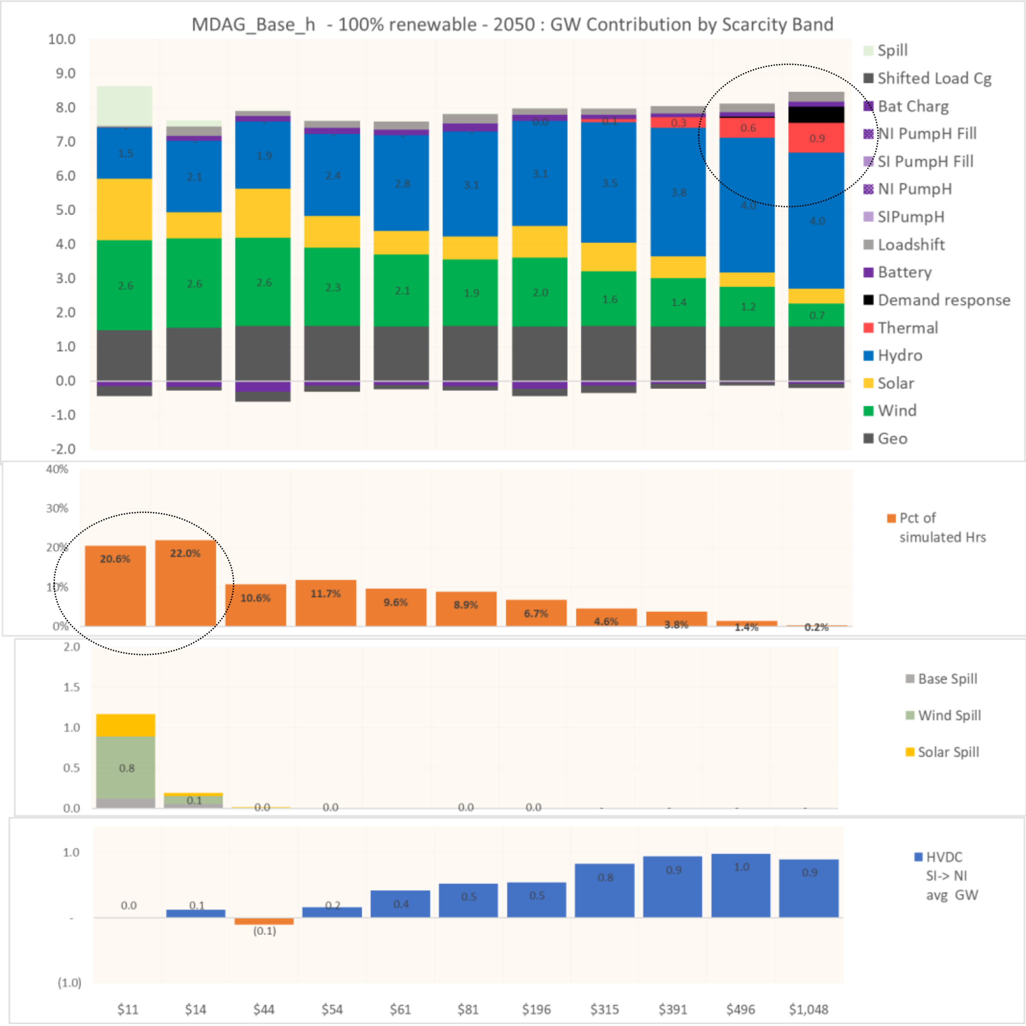
Individual "bins" ranked from low to high risk of scarcity

Chart explanation

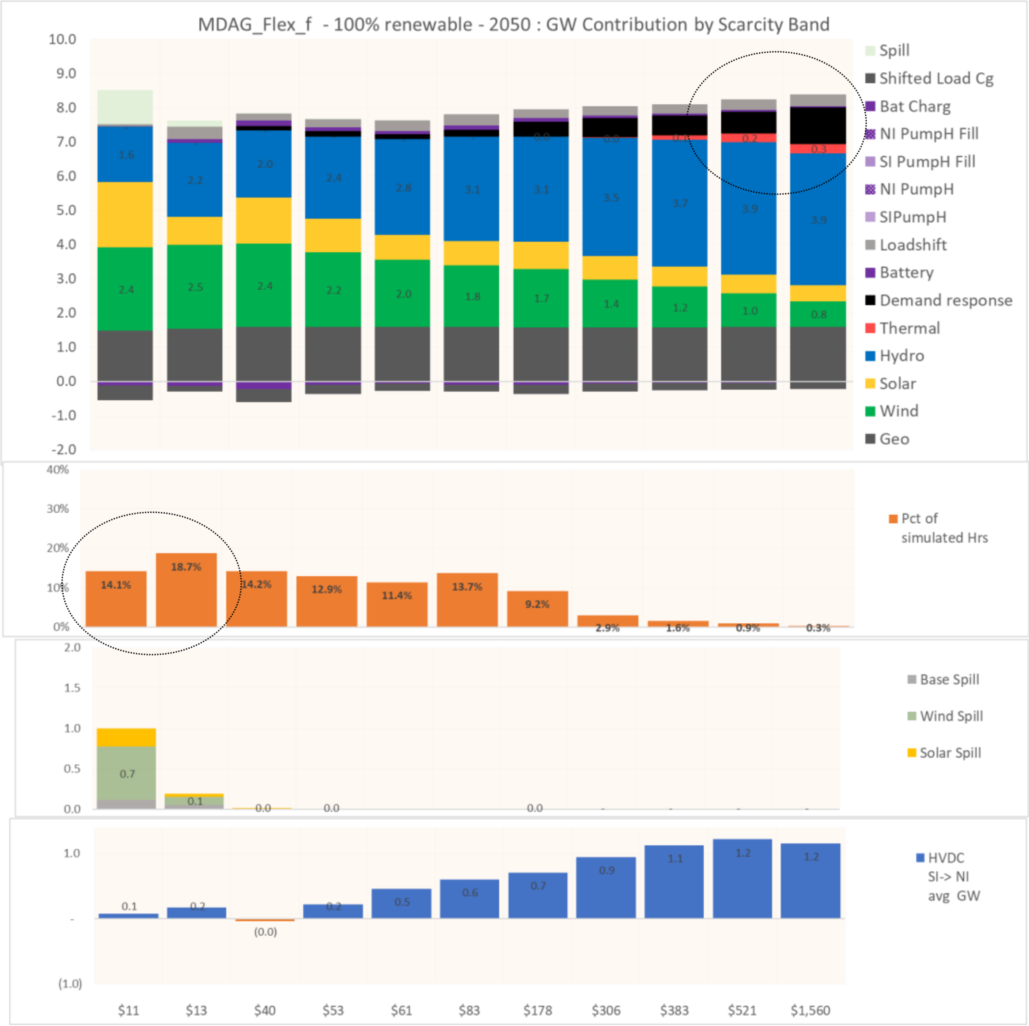
- These charts show the average MW contribution of different generation types in blocks of relative scarcity and shortage.
- The charts are made by putting each simulated period in to number of "bins" which are reflect the balance of supply and demand.
- Bins with excess supply and high risk of "spill" are show on the left and bins with relative shortage and high risk of demand response being required are shown to the right.
- The charts are useful to assess the value contribution of the different types of supply including intermitted supply (solar and wind), dispatchable hydro and thermal, and batteries of different sizes and duration.
  - Note that "Demand response" includes both voluntary curtailed load and shoratges. "Load shifting" is smart shifting of EV charging load within the day.
  - Batteries include different hours of storage (from 3 to 12 hours) and include that portion of behind the meter batteries that are scheduled according to system need.
- The percentage of periods in each indicated by the probability histogram.
  - The bins to the far right that correspond to demand response and shortage have low probability (typically < 1%) but a very high impact on cost.
- The expected level of "spill" in each band is shown below. This is wind, solar and geothermal being dispatched off when there is excess supply to meet demand.
  - The bins to the left include a high risk of "spill" when prices fall below the minimum offer prices for wind and solar.
- The final chart shows the expected level of South to North transfer on the HVDC link and illustrates the frequency of link limits being hit.
  - When the average HVDC S->N gets close to 1.4GW there is a high risk the HVDC limit becomes binding, and SI flexible resources can't be fully utilised to meet NI shortages.

Contribution curves show the impact of additional flexible demand response

Reference case 100% renewables with green peakers but no additional flexible demand. Flexible demand is included with demand response.



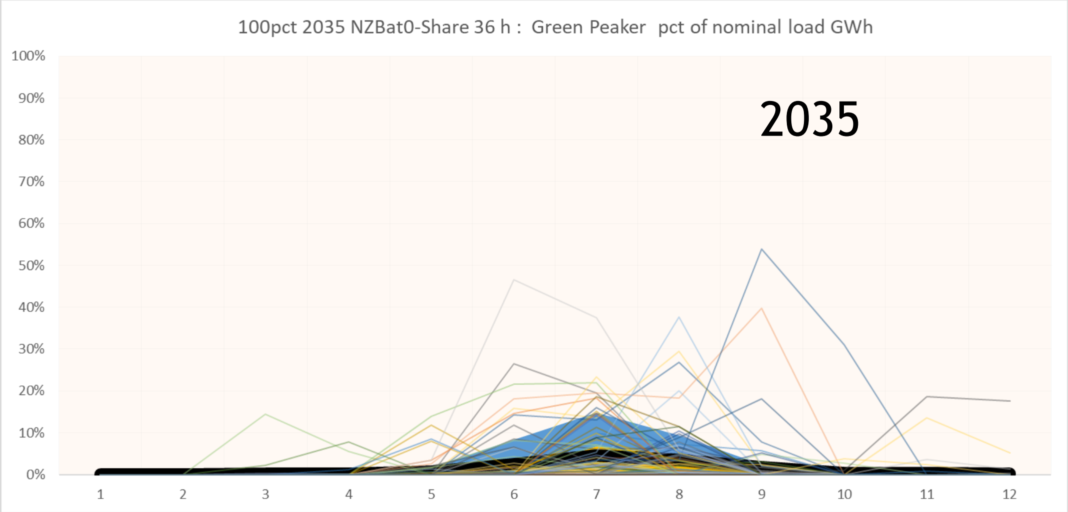
.. with additional flexible demand spill and green peaker use is reduced

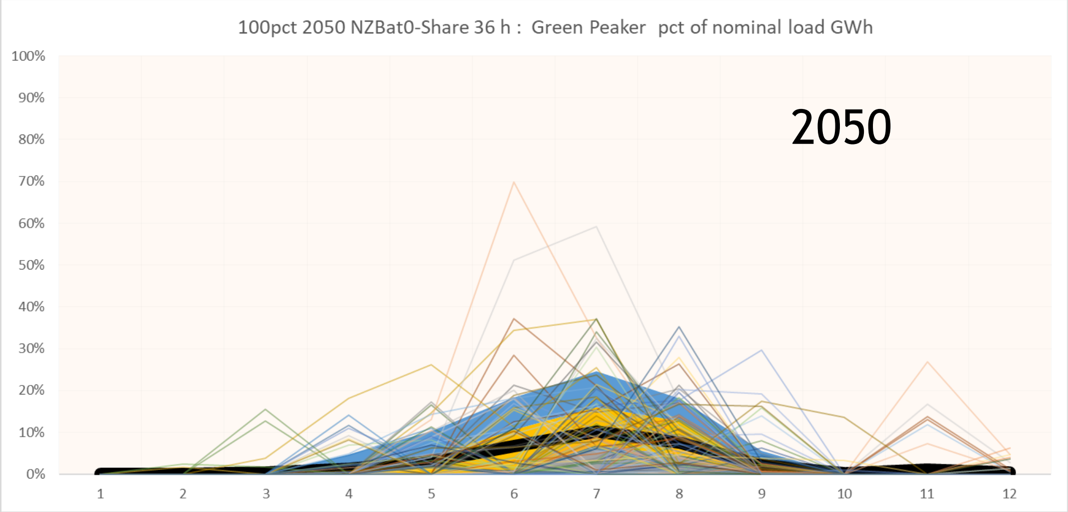


APPENDIX 7: GREEN PEAKER OPERATION AND FUEL STOCK REQUIREMENTS

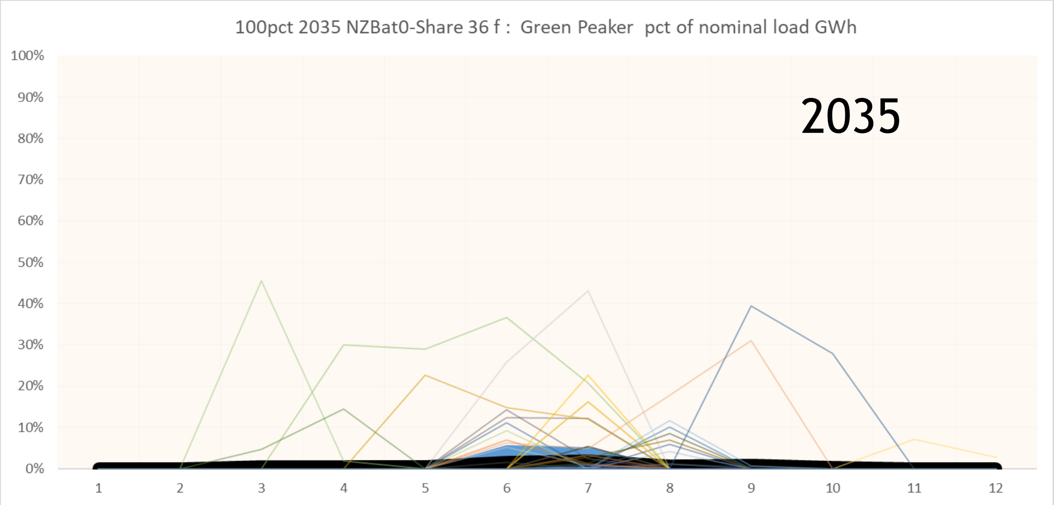
The need for a green peaker is significantly reduced in the enhanced flexible load scenario

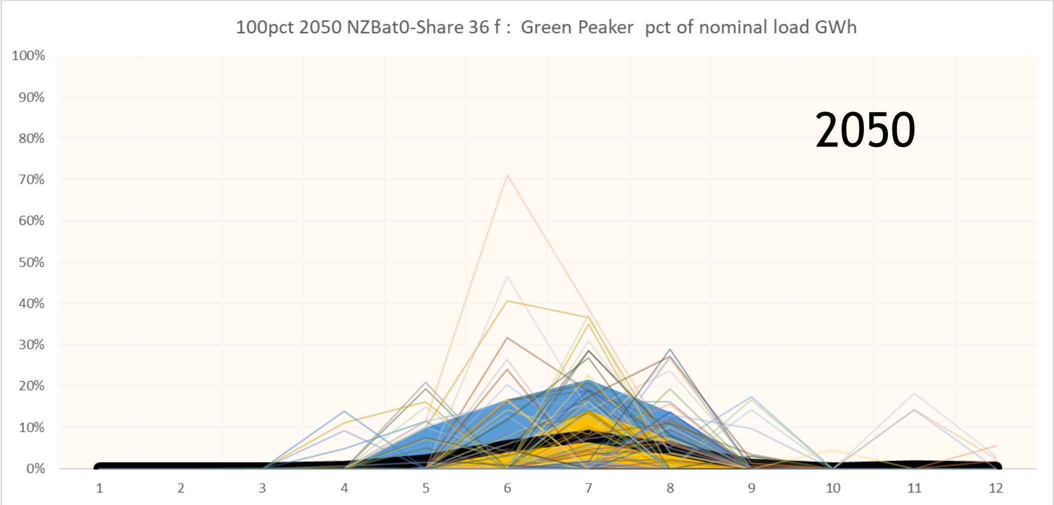
With reference case demand flexibility





With additional flexible demand

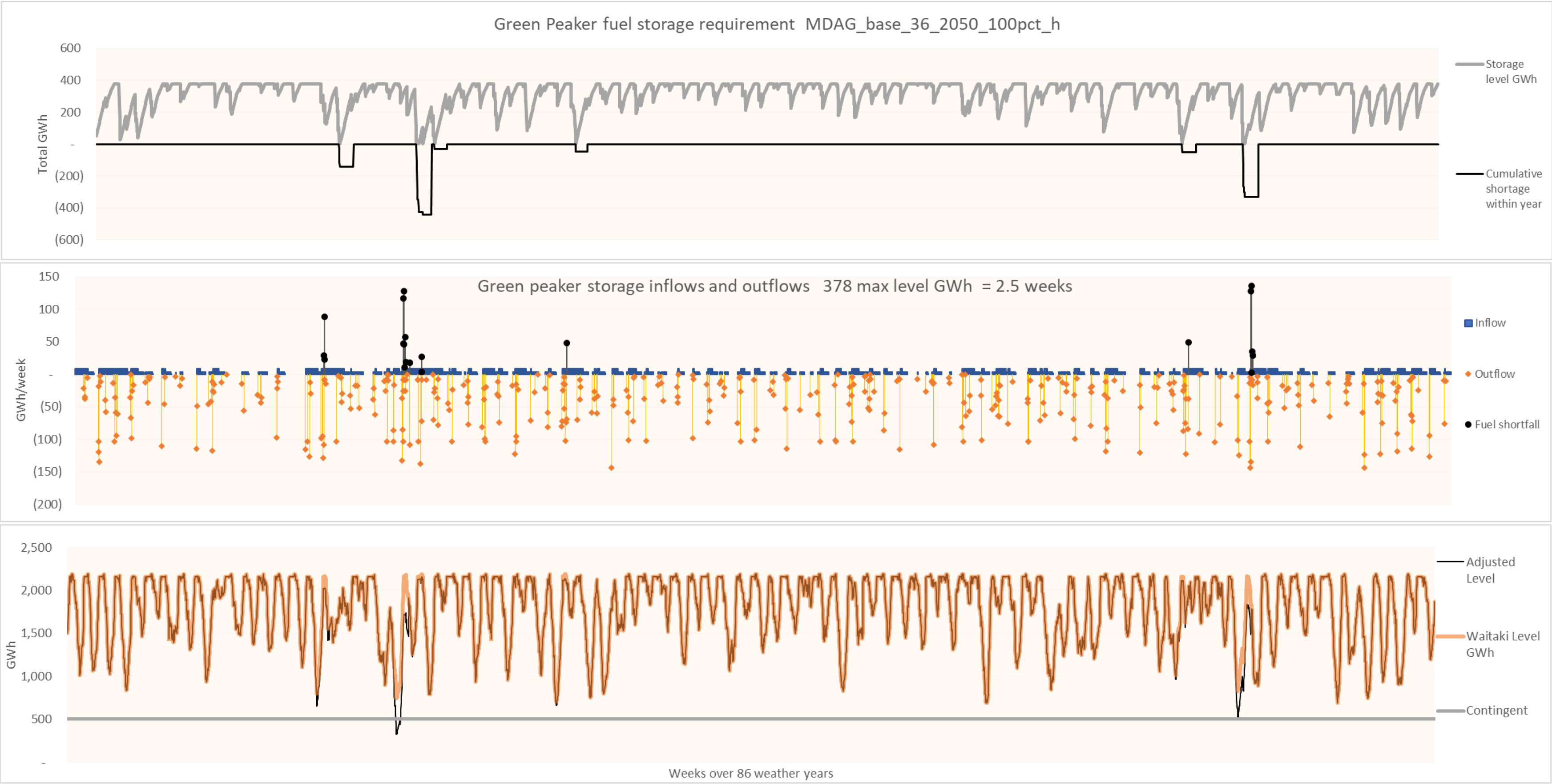




Note: the fine lines show results for each simulated weather year, the solid black is the average over all simulated years, the coloured bands are 10%, 25%, 50%, 75% and 90% percentiles.

Storage and supply chain requirements for last resort green peaker operation in the 100% renewable reference case in 2050

Green peakers will need around 2.5 weeks of fuel storage to meet the low wind firming requirements in the reference case. There are a few periods where the 2.5 weeks is insufficient, however these can be met all the modelled requirements. Other longer-term options will be required, such as use of use of contingent storage, or modest use of official conservation campaigns if necessary.



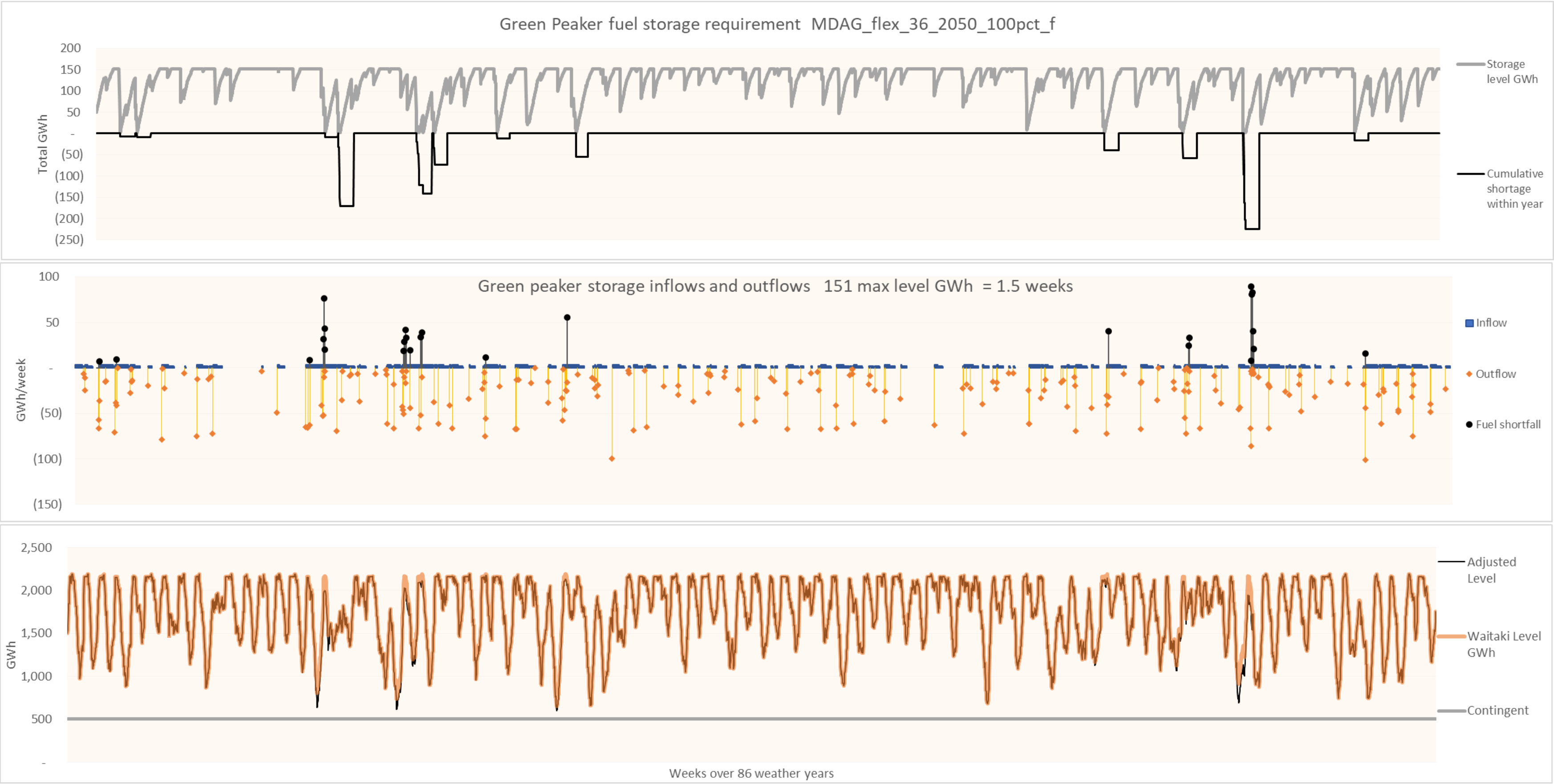
Note: the storage is measured in terms of the GWh of peaker operation. This can be roughly converted into PJ by dividing by 100. The one-off cost of filling the stockpile is approximately $130m (assuming 80% full @ $45/GJ), and there will be additional costs for biodiesel tanks or biogas storage facilities.

Commentary

- This chart shows the operation of a fuel stockpile for a green peaker.
- The base assumption is a storage of 2.5 weeks at full capacity.
- It is assumed that the fuel purchases are at the average level when the stockpile is between 20 and 80% full but can be boosted to 2x the average when storage levels fall low.
  - This is an approximation. Top-up supply might involve special arrangements for larger quantities with a time delay.
- The stockpile is used to supply the green peakers as the system requires to meet periods of low wind/solar/hydro. These occur on a regular basis most years, but occasional are bunched when lakes fall low.
- There are 3 to 5 periods out of 86 years when fuel storage reaches zero and green peakers can't meet the entire demand.
- In these cases, there will be a shortfall which would have to be met from other sources, such as drawing down into the contingent zone at Waitaki, or by low levels of demand control.
- For illustration, the charts assume that any shortfall within a year is corrected by the end of the year.

Storage and supply chain requirements for last resort green peaker operation in the 100% renewable flexible demand case are much lower

Green peakers will need around 1.5 weeks of fuel storage to meet the low wind firming requirements in the enhanced flexible load scenario. The extra backup requirements are much smaller and should be readily accommodated through use of contingent storage and extra calls on flexible load at much lower cost.



Commentary

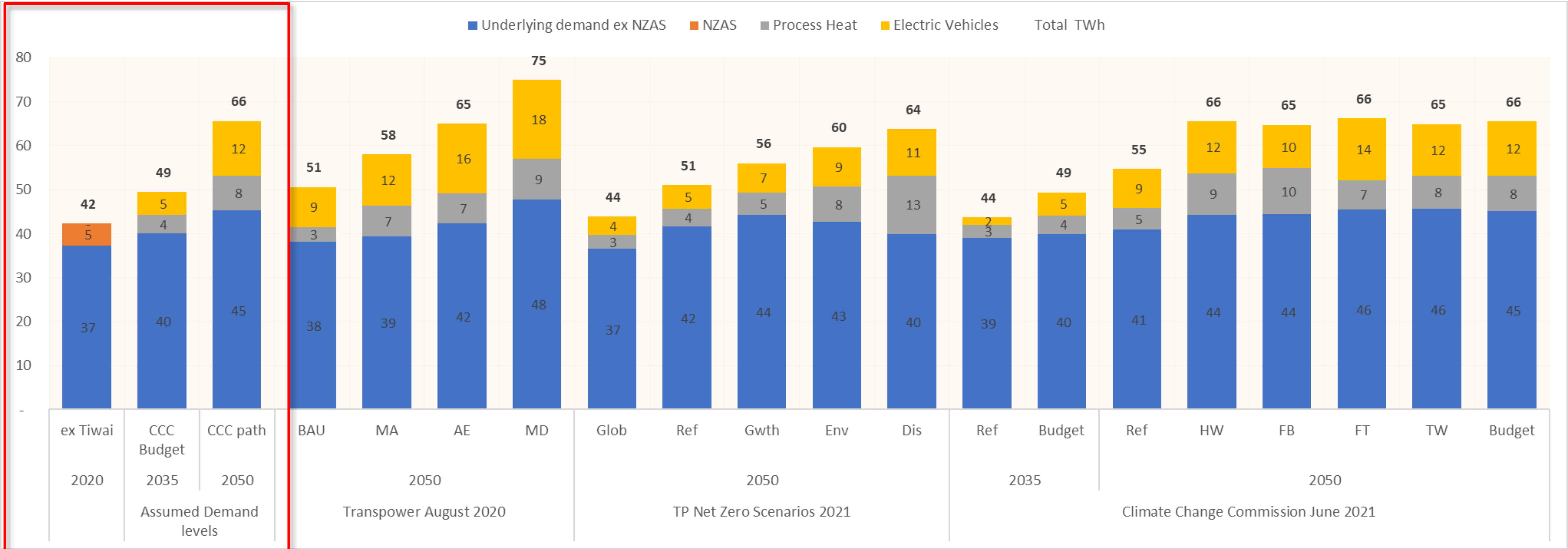
- Green peakers are still required to cover capacity shortfall during low winds, but the size and frequency of this backup is much reduced.
- This means the size of the green peaker storage is substantially lower and the impact of fuel shortfalls is much lower and more readily accommodated by other flexible supply.

APPENDIX 8: DETAILED ASSUMPTIONS SUMMARY

Demand – key assumptions

- We model demand in 2035 and 2050 representing 2 levels of decarbonisation.
- Demand follows the the Climate Change Commission's demonstration path.
  - This is broken down into underlying, new process heat and electric vehicle demand
- The seasonal pattern of underlying load and low temperature process heat follows historical patterns
  - New food processing heat follows a summer oriented dairy pattern
  - EV load has a slightly summer oriented profile
- **There is extensive allowance for short term demand management in the reference case.**
  1. Smart EV charging for 70% of average EV MW load is available – this allows load to be shifted up to 5hrs
  2. A portion of batteries associated with rooftop PV is assumed to be available to for wholesale market backup
  3. Demand response is available in various tranches priced from $700 to 1500/MWh
- The enhanced demand management scenario increases both flexible load and load shifting:
  - This increases smart EV charging load shifting by an extra 30%
  - And adds 400 MW in 2035 and 600MW in 2050 additional fully flexible demand triggered at prices ranging from $30 to $300/MWh.
    - This is assumed to respond to price only and can be sustained over hours or weeks as required.

We assume energy demand growth is consistent with the Climate Change Commission demonstration path to net zero by 2050 - this has



Reference case assumptions:

- Tiwai closes by 2035
- Energy demand rises 20% by 2050 and almost 60% by 2050.

Our reference case for 2050 is like Transpower's Accelerated Electrification scenario

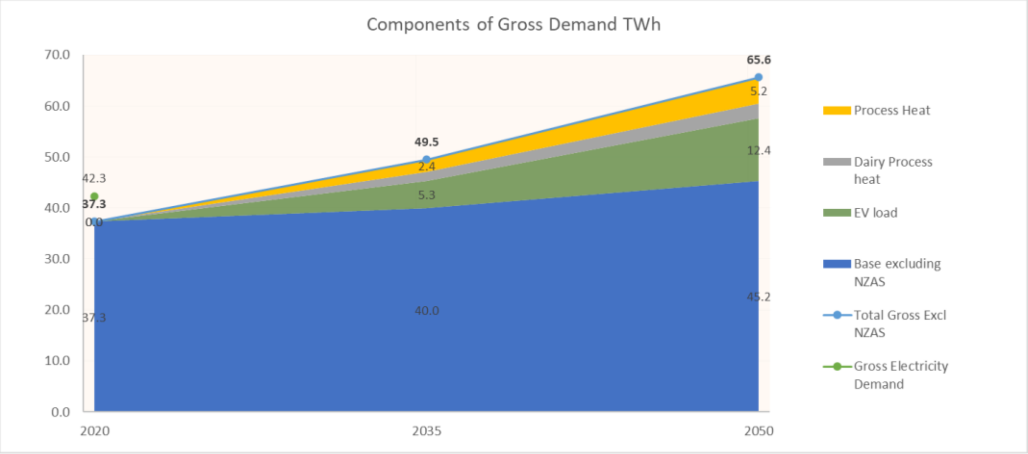
Our reference case for 2050 is a little higher than Transpower's Disruptive Scenario

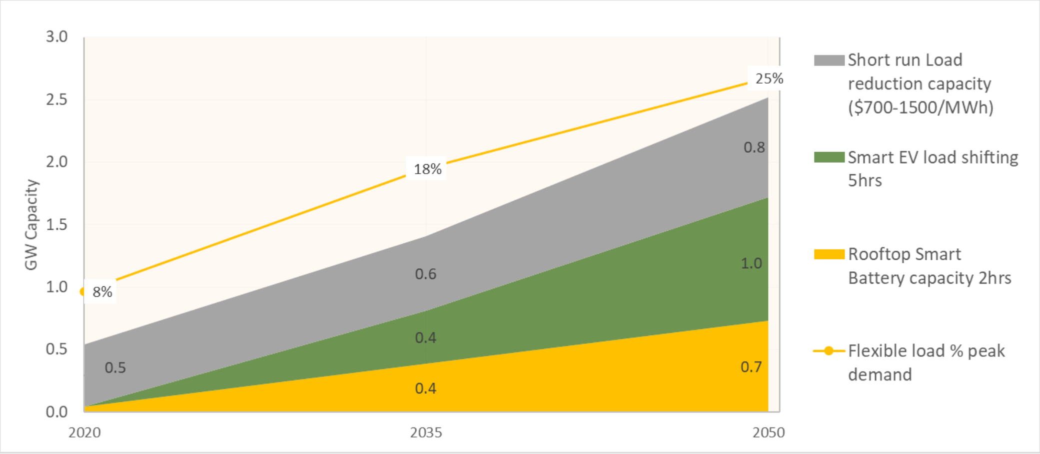
We are consistent with the Climate Change Commission's Demonstration Pathway (Budget) to net zero by 2050

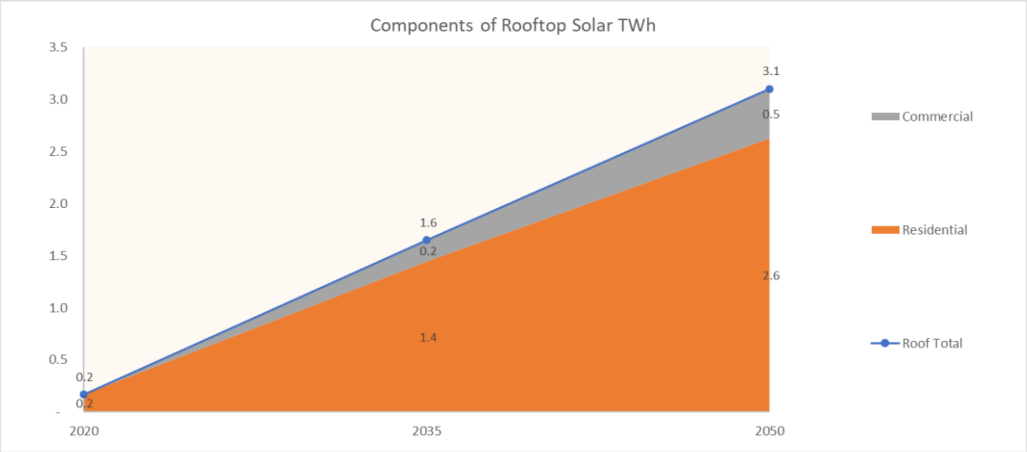
Our reference case assumes that electric vehicles and process heat drive the growth in gross energy demand

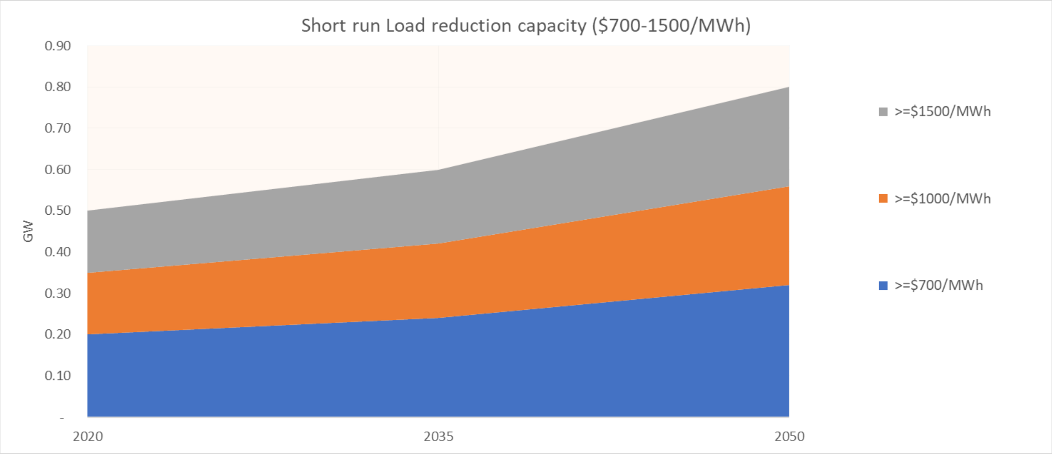
EVs and process heat drive the increase in gross electricity demand. Underlying electricity demand growth is largely offset by efficiency gains.

Note the very significant increase in price responsive flexible demand from 8% to almost 25% of peak demand by 2050.







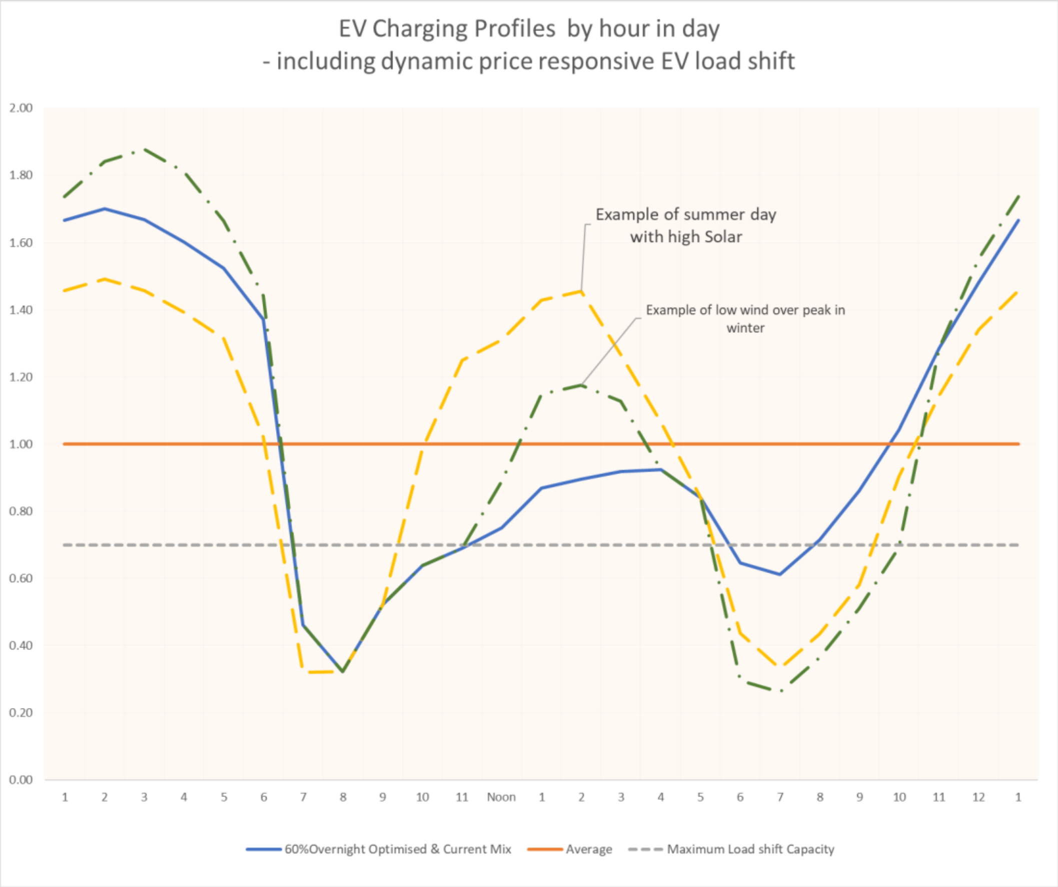


It is assumed that rooftop solar grows steadily and reaches 30% of electricity customers by 2050.

Short run demand response is assumed to be priced from $700 to $1500/MWh in three tranches as shown above.

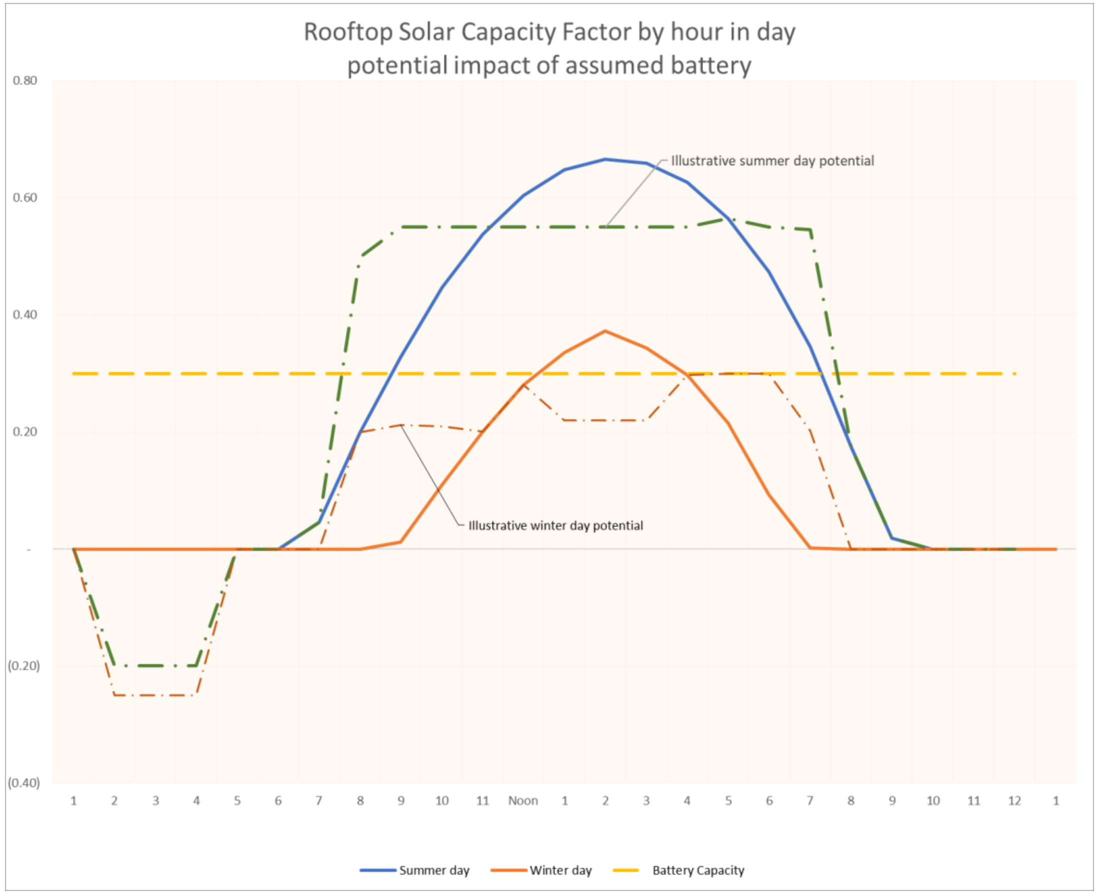
Electric vehicle charging profiles and behind-the-meter solar batteries

The assumption is that EV charging follows a 40:60 mixed convenience and overnight charging profile with an additional load flex available as required by changing supply and demand mix with changes in weather and demand and according to the supply mix.



The chart shows an illustrative potential adjustment to the EV charging profile in a summer and winter day. In the model the EV charging profile is modified as required by the system overall in each modelled day and demand/weather scenario.

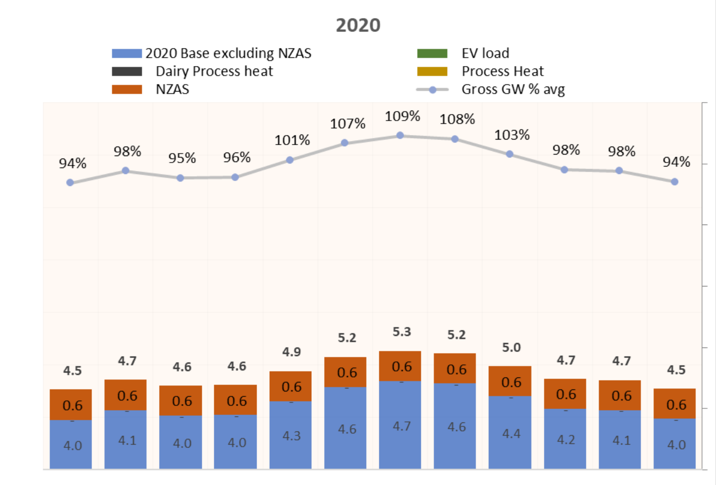
On average, it is assumed there is 30% of 3 hr distributed batteries installed with each 1.0MW of rooftop solar. These batteries are assumed to be operated flexibly according to the need from the system in each modelled demand/weather scenario.

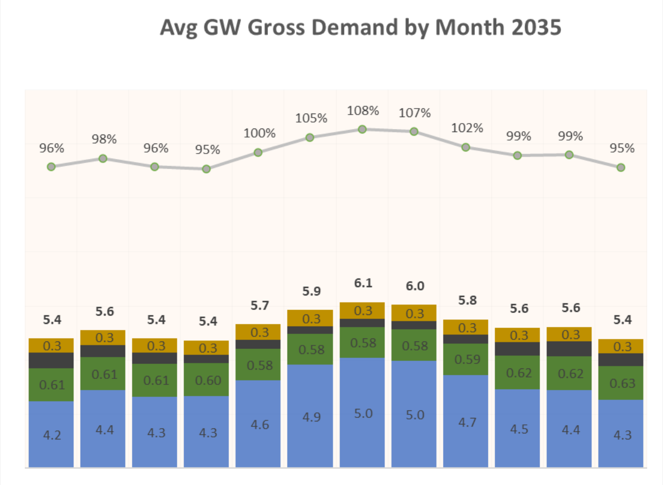


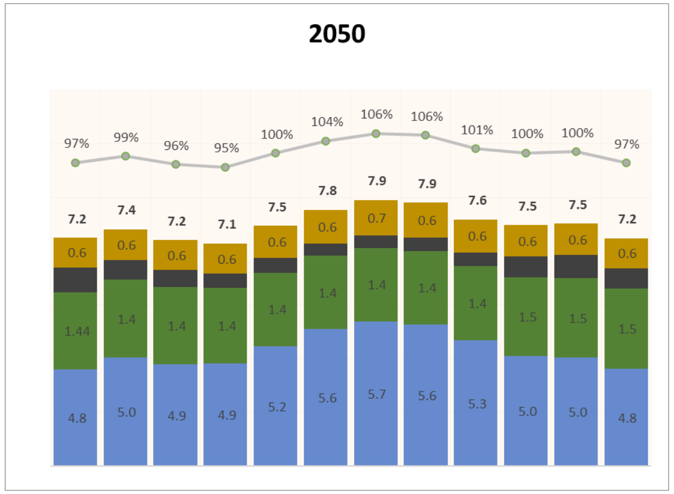
The chart shows an illustrative winter and summer capacity factor profile.
In the model the solar batteries are scheduled as required by the system overall in each modelled day. This is a simplification. In reality, some batteries will be operated to meet other objectives such as to minimise net exports.

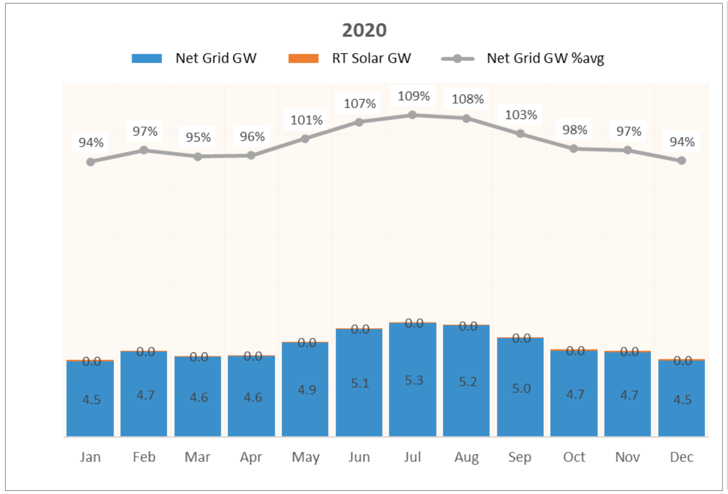
Seasonal shape of demand - expressed in terms of average GW per month

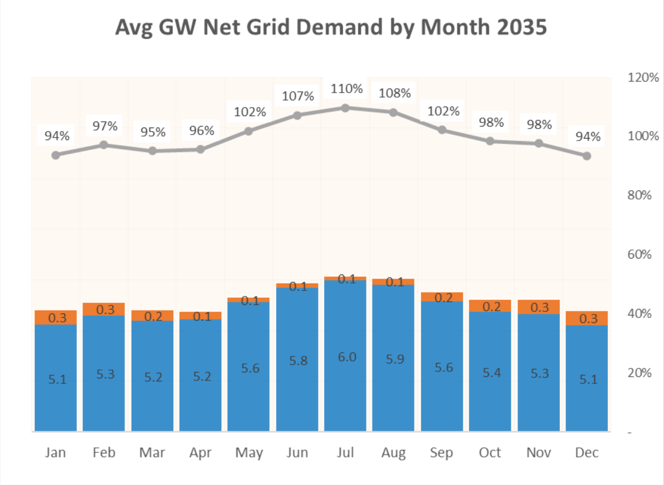
The gross seasonal demand shape is slowly flattening as the percentage of total demand relating to electric vehicles and process heat increases as a result of decarbonisation. However, this seasonal flattening is offset by increases in rooftop solar.

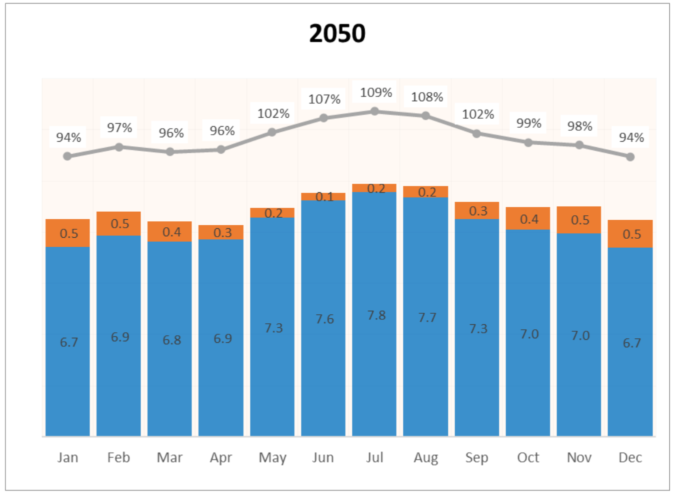












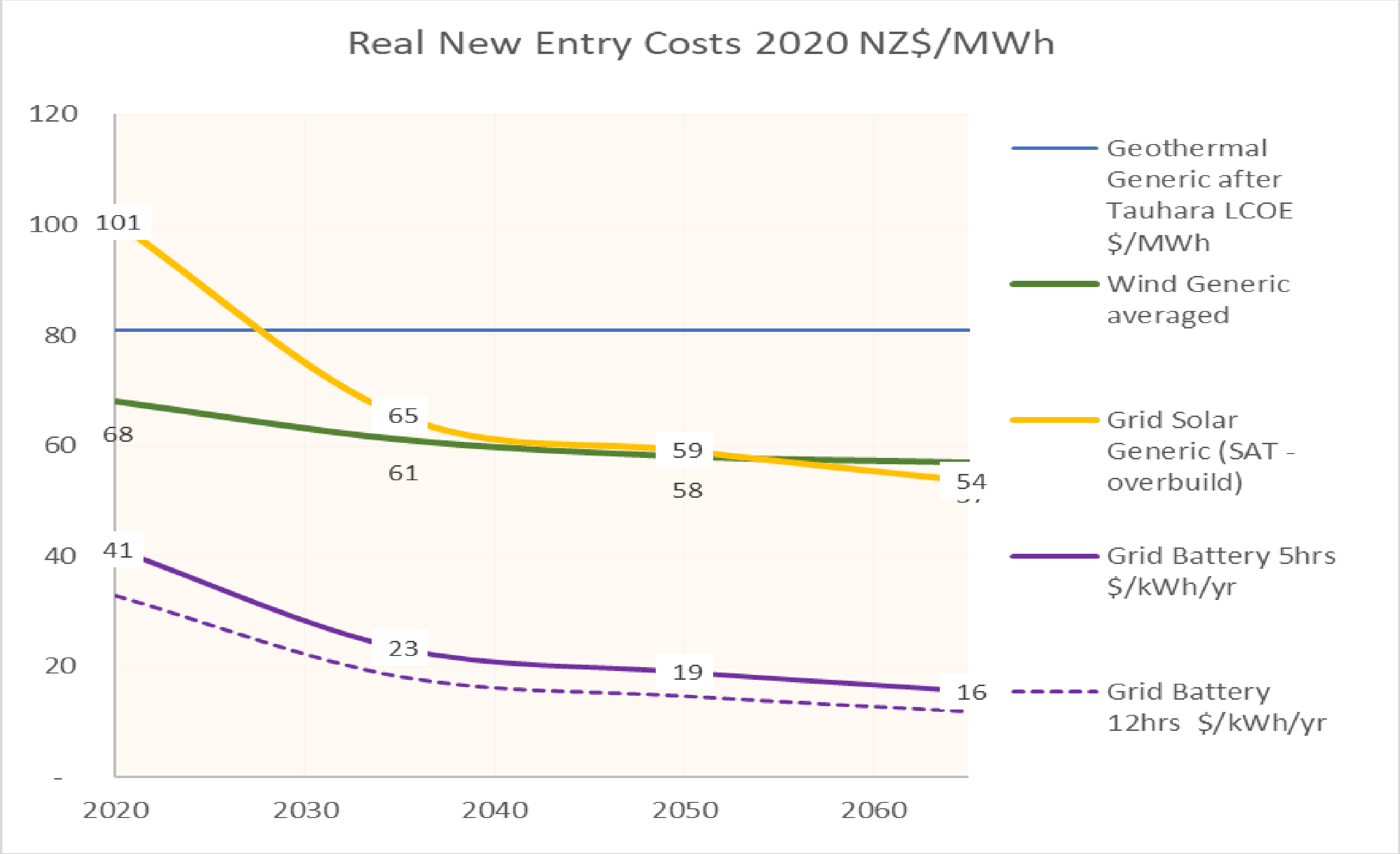
Note: Dairy process heat is assumed to follow existing seasonal profile with lower demand in winter and higher in summer. The seasonal shape of low/mid temperature demand assumed to follow underlying demand. It is assumed there is a slight summer seasonal shape for EV demand following the seasonal shape of existing petrol demand.

Transmission and new supply – key assumptions

- We model HVDC losses/constraints explicitly - HVDC capacity assumed to be 1400 MW (north) and 950 MW (south) and we assume no reserve-related transfer limits on basis that NI batteries should be able to support full reserves requirements
- Average HVAC losses are included in demand and AC grid is assumed to be unconstrained
- The model has a menu of new supply and demand response options available for development/use at different costs:
    1. New hydro – we assume no new hydro is available
    2. Geothermal – up to 1.3GW of new capacity is available
    3. Wind – unrestricted MW are available with downward sloping levelised cost of energy curve
    4. Grid connected solar – unrestricted MW available with downward sloping cost curve
    5. Rooftop solar – the volume of uptake is exogenous to model and rises to 4.0 TWh by 2065
    6. Batteries with rooftop solar provide the equivalent of 30% of average rooftop solar MW with 3hrs storage
    7. Unrestricted 5- and 12-hour grid battery systems are available to shift supply within days (provided they cover capex and opex)
    8. Smart EV charging for 70% of average EV MW load is available – this allows load to be shifted up to 5hrs
    9. Demand response is available in various tranches priced from $700 to $1500/MWh
    10. New zero-carbon thermal generation peaker is available with fuel cost of $45/GJ (real $2021) – as a proxy for last resort capacity options from flexible biofuel or green hydrogen
    11. Carbon prices in 2021 $ terms follow the CCC assumptions of $160/t and $250/t in 2035 and 2050.

We assume wind and solar costs decline over time in real terms

New entry costs fall modestly for wind and strongly for solar and batteries



Commentary

- Costs for solar and wind have been declining and further falls are expected
- Our estimates reflect recent projects and market information from NZ and Australia (including AEMO planning assumptions for Australia translated to NZ conditions cross checked against NREL technology benchmark costs adjusted to NZ conditions).

Note: These costs assume a 7% post tax nominal weighted average cost of capital. They account for tax depreciation and 2% p.a. inflation. Construction periods are 1 year for wind, solar and batteries and 3 years for geothermal. Economic lives are assumed to be 17 years for battery systems, 27 years for wind, 25 years for and solar and 30 years for geothermal. Potential generic capacity factors are assumed to be 41% for wind and 21% for grid solar (with single axis tracking and oversizing panels relative to other infrastructure). Solar costs assume 0.5% p.a. panel degradation.

Variability in supply - key assumptions

- We have modelled variability in supply and demand as follows:
  1. Hydro
     - The model uses 86 years of synthetic weekly hydro inflow data derived from the historical period 1932 to 2017. These account for the major catchments in each island and a separation between tributary and controllable inflows. The data is based on the EA Opus (now known as WSP) data sets calibrated to historical actual generation levels. Run of river hydro are based on actual generation back to 2000 and Opus series prior to that. To deal with multi-year storage limitations the model runs through a full set of inflows year by year with the starting storage being set from the simulated end storage the year before. This ensures that there is a range of starting storage positions, but the starting and ending storages averaged over all runs are virtually the same so there is no need to adjust averaged results for changes in average storage (see slide 59).
  2. Wind
     - The model uses 18 years of synthetic hourly wind data (2000 to 2017). This is based on actual data where possible for existing wind farms and profiles derived from the renewable ninja web site (satellite data based) for representative regional sites. These 18 years (for wind, solar and demand) are repeated for hydro years prior to 2000.
  3. Solar
     - The model uses 18 years of synthetic hourly solar data (2000 to 2017). This is based on profiles derived from the renewable ninja web site (satellite data based) for representative regional sites. These 18 years are repeated for hydro years prior to 2000. Separate profiles are provided for rooftop and grid connected solar (the latter is assumed to have single axis tracking).
  4. Demand
     - The model uses 18 years of hourly demand profile data (2000 to 2017) and seasonal profiles which reflect the average over the last 10 years. Historical demand variations are included in the modelling along with wind and solar supply variation.

Modelling of new investment in generation and small scale batteries

Approach

- In essence, for a given level of future demand and assumed existing supply the model calculates the "revenue[1]" available from incremental investments in different new supply resources (wind, geothermal, Li-ion batteries etc.)
- These revenue sums are compared to the annualised costs of the different options (noting costs decline over time)
- When revenue for a resource type exceeds its cost, we add more of a resource
- An iterative process of adding resource is followed until the point where further investment is no longer revenue adequate
- As discussed later, we have cross checked these planting results with a 'central planner' rule of minimising total costs – and the results are functionally equivalent – giving us confidence that the approach is robust

North/South

- The model tends to build new generation/small batteries mainly in the North Island – especially in the earlier years. This reflects the effect of HVDC capacity constraints, Tiwai shutdown, thermal plant closures, preponderance of demand

Regional wind/solar

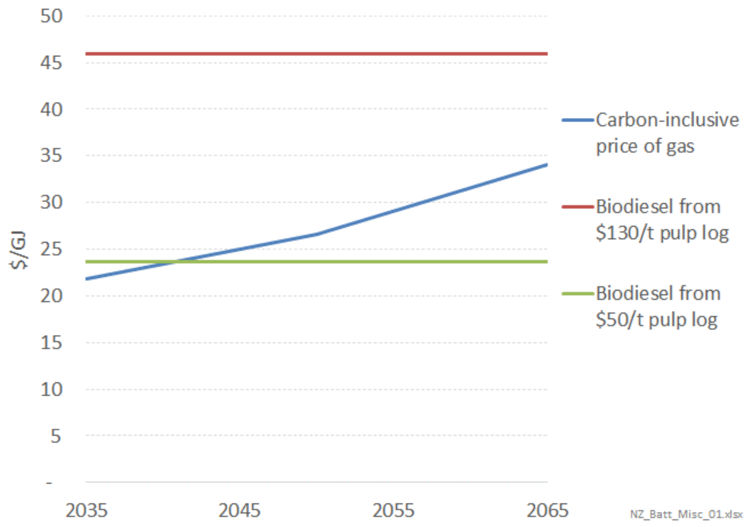
- The model places wind/solar investments in different locations to reflect effect of correlation issues GWAP/TWAP[2] factors (see later slide for more info)

1. The "revenue" measure is derived from prices which depend on assumed water value offer curves, the SRMC of thermal plant, and demand response and shortage cost tranches.
2. Generation weighted average price / time weighted average price. This provides a measure of how much of the average market price that a particular project can 'capture'.

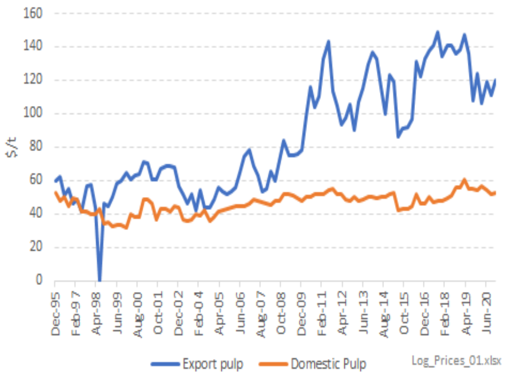
What are ‘green’ peakers?

- Green peakers are combustion turbines which use a zero-carbon fuel – such as biodiesel, biomethane or green hydrogen/ammonia.
  - Its possible that existing open cycle peaking plant might be converted to run on green fuels, but if necessary new plant could be constructed on existing or new sites.
- The capital cost for such turbines is well understood but there is some uncertainty over the fuel cost. Having said that, research by Scion[1] indicates biodiesel from pulp logs using an *existing technology* would cost roughly $25t-$45/GJ to produce depending on log costs. Existing oil storage infrastructure might be usable to enable sufficient flexibility for low capacity-factor operation.
- Also see the EECA/BECA report – which indicates that could be 5-13 PJ/yr of biogas and bio methane at a cost of $35 to $60/GJ. This would mean the existing gas infrastructure may be usable to provide sufficient supply flexibility to meet a low-capacity factor operation.
- Furthermore, the government’s recent in principle decision to mandate biofuels[2] for transport makes it likely biofuels will be available at scale by 2050 or before.
- Alternatively it is possible that green hydrogen or ammonia could be used if the infrastructure for production/import/export was developed for other local hard-to-decarbonise uses (e.g. heavy transport, aviation, etc.).
- Given these factors, we consider it reasonable to assume that a green peaker fuel will be available at $45/GJ ($2021) in 2035 and 2050

Effective delivered cost of gas and biodiesel



Historical pulp log prices



Cost and supply of Biogas and Biomethane

A further 5.6 PJ would become available in coming decades as natural gas prices increase above $35 /GJ, driven by Emissions Trading Scheme (ETS) price rises and natural gas scarcity. Out to 2050, 13 PJ could become available as hard-to-utilise feedstocks like animal manure and crop residue, which don’t stack up economically today, become viable at biomethane prices of $50-60 /GJ. **These high prices help to provide revenue for new plants that cannot charge a gate fee or maximise their digestate value.**

Scion, February 2018 report: *“New Zealand Biofuels Roadmap Technical Report*”, and MfE’s “*Marginal abatement cost curves analysis for New Zealand*”
See https://www.transport.govt.nz/area-of-interest/environment-and-climate-change/biofuels/

Summary table of key assumptions for modelling

Summary of high level demand and technical assumptions

Base Assumptions		MDAG Modelling Assumptions		
Years		2020	2035	2050
Gross Electricity Demand	TWh	42.3	49.5	65.6
NZAS	TWh	5.0	0.0	0.0
Base excluding NZAS	TWh	37.3	40.0	45.2
EV load	TWh	0.0	5.3	12.4
Dairy Process heat	TWh	0.0	1.8	2.8
Process Heat	TWh	0.0	2.4	5.2
Total Gross Excl NZAS	TWh	37.3	49.5	65.6
Rooftop Solar	TWh	0.2	1.6	3.1
Rooftop Solar	GW	0.1	1.30	2.44
Rooftop Smart Battery capacity 2hrs	GW	0.0	0.4	0.7
Smart EV load shifting 5hrs	GW	0.0	0.4	0.99
Short run Load reduction capacity ($700-2000/MWh)	GW	0.5	0.6	0.8
EV Profile	% optimised	65%	65%	65%
EV % NI	% NI	70%	70%	70%
PH Profile	% flat	100%	100%	100%
PH % NI	% NI	60%	60%	60%
RoofTop Solar	% NI	75%	75%	75%
Flexible load % peak demand	%NZ peak demand	8%	18%	25%
Peak Demand	GW	7.1	8.0	10.2
Load factor (P50 hourly) Base ex Tiwai	factor	68%	70%	73%
Modelled Demand for Gen		40.4	47.6	63.7
Model Underlying		35.4	40.6	48.5
			0.91%	1.20%

Supply Constraints	
Max New Geothermal	Up to 1.3GW additional GW
Base Thermal & cogen	All closed
Thermal	Unrestricted biofuel/hydro peakers @ $45/GJ available as last resort
Hydro	No new hydro included
Wind	Unrestricted
Grid Solar	Unrestricted
Batteries	Unrestricted 5 and 12hr BESS systems

Technical Issues	
HVDC Capacity	Effective capacity South to North and North to South (1400MW) and (950MW)
Unrestricted Grid Batteries	Allow unrestricted 5 and 12 hr batteries for within day grid dispatch
Behind the Meter Batteries (with Solar)	Assume that this is included in generic load shifting in response to price
Smart Demand control	Some level of price responsive within day load shifting (battery like)
Market demand response	Tranches at $700-2000/MWh - for market driven peak load reductions
Use of Contingent Storage	Allow very occasional use of contingent storage (Pukaki and Tekapo)
Lake Level driven dry year savings	Set dispatch according to spill and shortage risk levels and time of year
Large Storage dispatch rules	Level driven , with some seasonal and within day balancing operation.

Further detail and generic technology cost trends

Basis of Assumptions		MDAG Modelling Assumptions		
Years		2020	2035	2050
Underlying Demand				
Growth in Base ex NZAS	%pa		0.47%	0.82%
Base Growth	TWh	0.0	2.7	7.9
Efficiency	%			
Pop Growth	% pa		0.8%	0.6%
Residential	Million	1.80	2.03	2.22
Non_residential	Million	0.30	0.34	0.37
EV s				
EV Total	TWh		5.3	12.4
Light	TWh		4.2	8.2
Heavy	TWh		0.8	2.6
Off Road	TWh		0.3	1.6
Light	% vkm	0	45%	95%
Heavy	% vkm	0	2%	6%
Off Raod	% On Road		5%	15%
Light	vkm	41.7	51.2	53.0
Heavy	vkm	3.16	3.5	3.6
Light Efficiency	MWh/vkm	0.19	0.18	0.16
Heavy Efficiency	MWh/vkm	4.24	10.00	12.84
Process Heat				
Process Heat Total	TWh	-	4.2	8.0
Low and Mid Temp	TWh		2.4	5.2
High Temp (dairy)	TWh		1.8	2.8
% Dairy			42%	35%
Rooftop Solar				
Roof Total	TWh	**0.2**	**1.6**	**3.1**
Residential	TWh	0.2	1.4	2.6
Commercial	TWh	-	0.2	0.5
Residential	%	2.0%	15%	24.1%
Commercial	%	-	7%	15%
Resid installs	Num	0.04	0.29	0.53
Commercial Installs	Num	-	0.02	0.06
Residential kW/instal	kW	3.80	4.0	4.0
Commercial kW/Install	kW	7.00	7.0	7.0
			1.34	2.53

Generic Capital Cost $NZ 2020 dollars	Base $/kWac in 2020	to 35	to 50	CF	CRF
Geothermal Generic after Tauhara	5,500	-	-	91.0%	8.0%
Wind Generic averaged	2,200	-1.0%	-0.5%	41.0%	8.1%
Grid Solar Generic (SAT - 30% overbuild)	1,800	-3.5%	-0.9%	21.5%	8.7%
Grid Battery 5hrs	2,000	-4.0%	-1.5%		9.8%
Grid Battery 12hrs	3,900	-4.0%	-1.5%		9.8%

Fixed annualised Costs		2020	2035	2050
Geothermal Generic after Tauhara	$/kW/yr	629	629	629
Wind Generic averaged	$/kW/yr	208	183	172
Grid Solar Generic (SAT - 30% overbuild)	$/kW/yr	176	111	100
Grid Battery 5hrs	$/kW/yr	206	116	95
Grid Battery 12hrs	$/kW/yr	393	217	175

About Concept

For more than 20 years, we have been providing expert advice on policy, regulation, strategy and economics. We are energy sector specialists with growing expertise in carbon, telecommunications and water.

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