MBIE explanatory note on enclosed slide pack

Note, as at 12 August 2026: MBIE has released this updated version of the draft Concept slide pack, with all previous redactions removed.

MBIE commissioned Concept Consulting to utilise its modelling tools and databases to undertake electricity system modelling. The purpose of the modelling was to assist with understanding the impacts an LNG import terminal would have on future electricity prices across a range of scenarios. This was one input to a wider tranche of advice that MBIE was preparing for Cabinet. In particular, MBIE:

- *compiled information from a wide range of sources;*
- *drew on published reports, such as from Boston Consulting Group (BCG), and from subscription only reports such as Concept Consulting's (Concept's) June 2025 Electricity Price Forecast and various updates from market analysts such as Forsyth Barr and Enerlytica;*
- *commissioned several formal reports from Sense Partners;*
- *commissioned electricity system modelling from Concept; and*
- *undertook its own analysis and assessments.*

The enclosed draft slide pack is a working document that was used as a vehicle for Concept Consulting to progressively set out information relating to modelling approaches, limitations, input data, assumptions, scenarios, insights and model outputs. It was strictly for the purposes of free and frank engagement between Concept and MBIE as the modelling progressed. As such, it was a working document that Concept progressively updated over time.

The ultimate output of the Concept modelling process that fed into MBIE's advice for Ministers is reflected in the final modelling information from Concept that MBIE proactively released on 16 February 2026 and is publicly available here: https://www.mbie.govt.nz/dmsdocument/31770-concept-consulting-modelling-results-for-lng-analysis and in the Cabinet paper which Ministers proactively released here: https://www.mbie.govt.nz/dmsdocument/31754-government-investment-in-dry-year-risk-cover-consideration-of-an-lng-import-facility.

Modelling of spot prices for 2028 and 2035 – with and without LNG availability – shows that in most scenarios, LNG reduces spot prices in both normal and dry years. LNG delivers two key benefits: (i) having a capping effect on spot prices at LNG's marginal cost, and (ii) enabling greater use of low-cost hydro generation when operators have confidence in reliable back-up.

The latter means that having certainty of gas back-up promotes increased renewable generation. Modelling indicates that in the most likely scenarios, LNG would be likely to lower average electricity spot prices in 2028 by $58/MWh (if a dry year) or $10/MWh (if a normal year). By 2035, the modelling shows LNG reduces spot prices in a dry year in nearly all scenarios modelled.

Regarding the modelled need for LNG in the enclosed slide pack, MBIE makes the following comments:

- *The modelling shows scenarios where LNG is needed for electricity generation to supplement domestic gas. For example, in one scenario where there is high electricity demand, LNG is needed for electricity generation in 12 of 43 "weather years".[1] In another*

[1] "Weather years" refer to modelled years with different hydrological inflows wind flows and sunshine.

scenario where electricity supply and demand are in balance, LNG is needed for electricity generation in 5 of 43 "weather years". This is consistent with MBIE's finding that LNG is needed to support the electricity system by supplementing domestic gas in a dry year. This is the insurance value of LNG for the electricity system.

- *The results in the slide pack about the quantity of LNG needed are underpinned by assumptions about (1) the level of domestic gas production and (2) the ability for gas to shifted from industrial users to electricity generation if needed. Official gas production data was released on 14 May 2026, showing New Zealand's natural gas proven plus probable (2P) reserves declined 23% from last year. As gas supply declines and Māui and Methanex exit, the ability to temporarily redirect gas from industry to electricity disappears. Achieving the same outcome in the future (i.e. shifting gas from industry to electricity in a dry year), would require the simultaneous curtailment of a very large number of firms.*



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concept consulting

Analysis of effects of early LNG development for New Zealand

5 December 2025

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Key insights

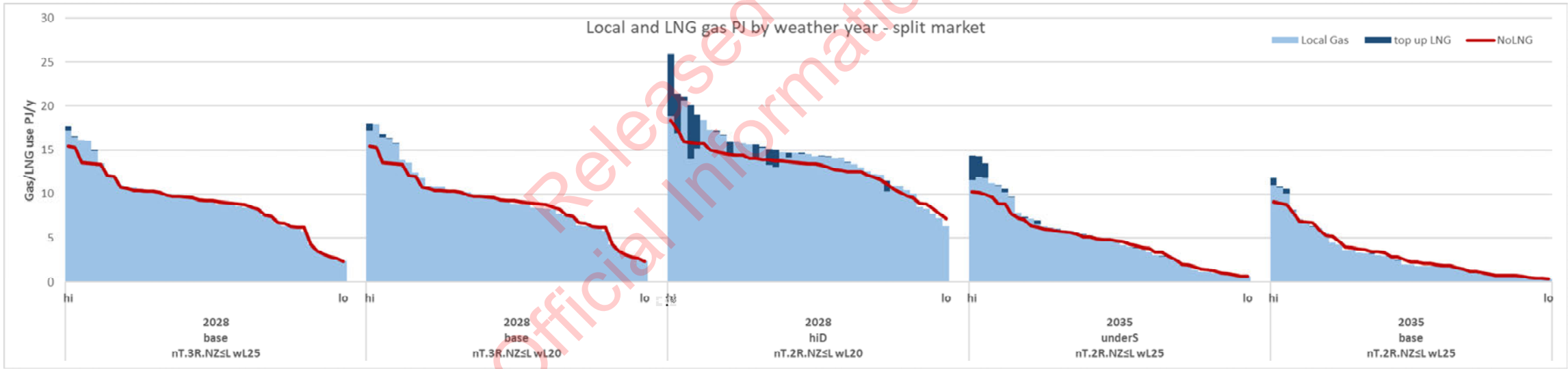
- Access to LNG should reduce electricity prices in the most extreme dry years if we have one or more of the following downside risks occurring:
  - Materially slower build of renewables relative to demand growth
  - Further significant decline of local gas supplies and no additional gas storage
  - 'Black-swan' risk of significantly reduced coal-fired generation available during a dry year
- However, unless it results in increased average NZ gas prices, it shouldn't materially affect average electricity prices. (This is particularly in the long-term (5+ years' out) as electricity prices should be driven by the LRMC of new renewables – a value that is largely independent of gas price)
- Other resources can provide a similar system security service to LNG. Modelled options* include:
  - Coal at Huntly
  - Additional underground gas storage such as the proposed Tariki field
  - Building additional new geothermal, wind and solar
- LNG is called upon relatively infrequently: only materially called upon in a few dry years (particularly if other downside risks are assumed to occur), but mostly not called upon in other years, with low average annual LNG throughput (averaged across weather years)
- Assumptions around gas prices (NZ prices without LNG, and LNG-driven prices) have a significant effect on system cost calculations.
  - If there is insufficient competition in local gas markets, there is a risk that local gas prices might increase up to LNG prices, and increase average electricity prices. (Note: The cost of higher gas prices to non-powergen users in such scenarios is not currently incorporated in the impact calculations)
  - We have not modelled any fixed LNG infrastructure cost recovery through this modelling. If this was recovered through the $/GJ LNG price it could imply a materially higher price than assumed in the modelling.

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* Other possible options such as diesel generation or increased Tiwai smelter demand response haven't been assessed in this exercise

Modelled need for LNG is low, even in scenarios with less other security resources

- Modelling identifies whether gas for power generation is from local gas or LNG top-up
  - LNG is only called upon if deliverability from local supply (gas fields + gas storage) is exhausted
- The scenario with most significant LNG requirements is the 2028 significant market stress scenario: high demand, only committed renewables developed, only 2 Rankine units, and no Tariki gas storage. This requires 7 PJ in the driest year and 0.7 PJ/yr on average
- Scenarios with more balanced renewables or 3 Rankine units or Tariki require much less LNG - none at all in some cases

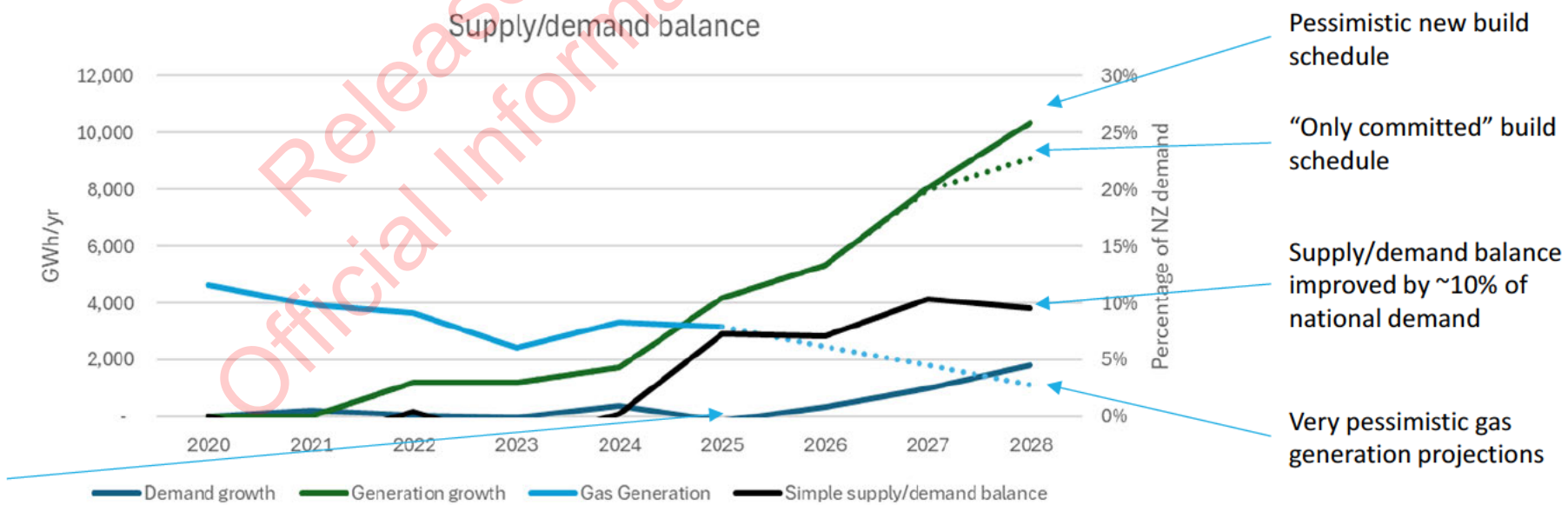


- Note: If LNG infrastructure is developed, it could possibly substitute for local gas if its presence resulted in a reduction in local development-well drilling as part of a dynamic resulting in local gas being priced-up to LNG levels

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Why is there minimal LNG used?

- This is the result of:
  - Domestic gas is used (when available) ahead of more expensive imported LNG
  - Coal in a Rankine unit is cheaper than LNG in an OCGT
  - A significant improvement in New Zealand's supply/demand balance since winter 2024
    - Renewable generation build has progressed, while demand has been flat since 2020
      - Growth in residential demand has been counterbalanced by a decline in industrial demand – almost entirely due to exits in the wood processing sector – and commercial demand has been flat. 2024 and 2025 saw some temporary demand reduction at the Tiwai aluminium smelter
    - This is counterbalanced by a decrease in available gas for generation through 2024
    - Even accounting for gas decrease, supply/demand balance improves by ~10 % of national demand



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Analysis framework

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Analysis framework

- LNG is being considered as an insurance option to reduce impacts during dry years.
- Modelling undertaken for three future years (2028, 2030, 2035), each with paired LNG scenarios '**W. LNG'** and '**No LNG**', for different state-of-world scenarios varying key downside risk assumptions:
  - NZ gas supply
    - NZ field deliverability available for power generation. **'Base Gas'** or **'Low Gas'**
      - NZ gas price is linked to field deliverability scenarios
    - Whether the Tariki UGS facility is developed. **'With Tariki'** or **'No Tariki'**
  - The extent to which base LNG price drives domestic NZ gas price (see below)
    - Two base LNG price scenarios considered ($25 and $20/GJ)
  - The number of Huntly Rankine units available: **Two** or **Three**
  - The extent to which renewable build reduces the need for thermal generation. **'Balanced-'** or **'Under-' build**
  - The potential for an extreme 'black swan' thermal outage. (Loss of all Huntly Rankine unit(s) during a dry winter)
- Modelled effect of LNG is to
  - Have unlimited gas supply deliverability for electricity generation. This is a key assumption for LNG to deliver benefit.
  - Alter gas prices.
    - There is uncertainty over extent to which lack of competition in NZ gas supply will result in all gas supply being priced at LNG levels, or whether only the LNG used by powergen pays LNG prices.
- The effect of LNG is measured for key metrics:
  - Electricity spot prices (average and in dry years)
  - Resource usage: Gas (NZ gas and LNG); Thermal generation; and Shortage
  - System costs

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Modelling undertaken using Concept's "ORC" model

- Fully-chronological hourly model that models the dispatch of generation and demand response, and subsequent electricity prices, for every hour in a year
- Each future year is run across 43 'weather years' with hydro, wind, and solar inflows using coincident historical data from 1980 to 2022. Relationship of demand with weather is also modelled
- Future demand is exogenously specified
- Generation build:
  - Exogenously specified for early years (ie, 3-4 years out) based on Concept's build pipeline database
  - Endogenously modelled for later years, with ORC building additional renewables, thermal peakers, and batteries such that just enough new plant of each type is built to achieve revenue adequacy. Ie, the subsequent electricity prices are just enough to cover the plant's capital, fixed, and variable costs and provide a return on investment.
  - Scenarios test the effect of generation build being less than required – exogenously specifying a degree of under-build for later years
- Hydro storage and release decisions are modelled using endogenously derived water-value curves
- Gas storage is also endogenously modelled based on assumptions around NZ gas field deliverability and underground gas storage (UGS) capability: PJ size of 'tank' and TJ/day size of 'tap'. Assumed base gas prices are endogenously adjusted 'on-the-day' based on the UGS storage level.

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Description of key assumptions

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Description of key assumptions

- The effect of LNG is to provide unlimited fuel when needed, thereby overcoming the constraints that can occur during dry periods if NZ gas deliverability (from fields and underground gas storage) is limited and other resources (eg, coal-fired Rankines, renewable build) are also limited
- The extent of possible limitations of NZ gas supply and other resources are therefore critical in determining the extent of benefit from LNG
- Scenarios have been used to test the effect of changes to key assumptions for these factors and the cost of LNG
- This section sets out the assumptions used

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NZ Fuel deliverability assumptions

- Two key assumptions:
  - The amount of upstream deliverability available for power generation
  - Whether additional underground gas storage (UGS) at Tariki is developed
- In terms of upstream deliverability, the graphs on the next slides indicate that the assumed upstream deliverability available for power generation (the 'Modelled elec gas' blocks in the Gas Demand graphs) are conservative – probably excessively so for the V.Low gas scenario:
  - There is likely additional field deliverability for power generation (the 'Extra gas available' blocks) which hasn't been taken into account in the modelling.
  - If the reduction in gas demand from non-power generation users is greater than illustrated (as the gas pipelines expect, as shown in slide 14), or the available gas from NZ fields is greater than projected, there will be even greater gas available for power generation
    - Note: The assumed exit of Methanex at end of 2027 isn't assumed to radically increase gas availability for power generation in 2028, even though this is a likely outcome
  - Conservative values were used as the engagement scope and timescale didn't cover the detailed gas modelling necessary to establish the likely extent of additional field deliverability for power generation
  - However, note that from 2030 onwards, due to falling renewable costs and increased carbon prices, not much more gas is desirable for power generation than assumed, even were it to be available. Gas use concentrated in dry years, particularly in scenarios of delayed renewable build
- The graphs on the right on the next slides illustrate that additional UGS would significantly improve fuel deliverability through being able to store even greater amounts of gas during 'wet' periods and deliver much greater quantities when required during 'dry' periods

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The modelled base case gas assumptions are conservative

Average annual production PJ/y

Average annual Consumption PJ/y

Daily deliverability for power generation "tap"

The base case potential gas supply reflects the low net production profile provided by MBIE

The base assumptions used in the modelling are shown by the dark grey blocks.

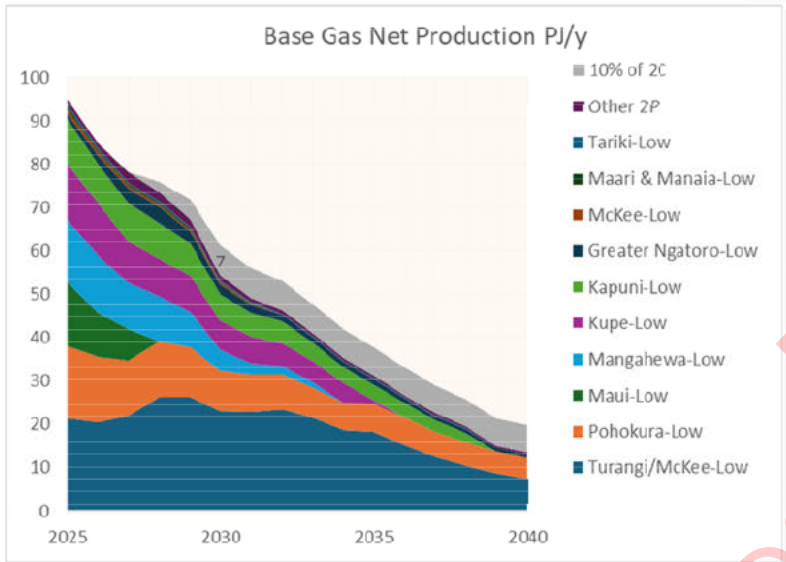
Light grey blocks show the extra potential supply for electricity which can be stored in the fields for future years

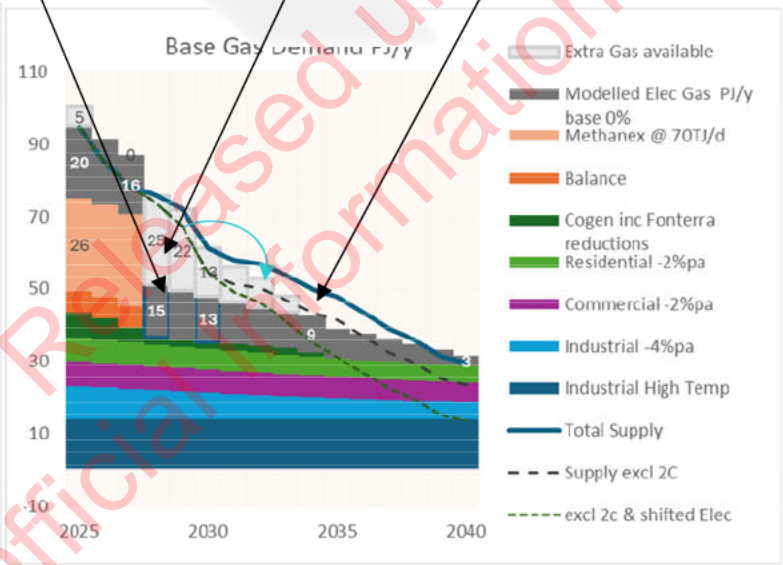
The dashed line is the potential supply for gas generation, excluding 2C

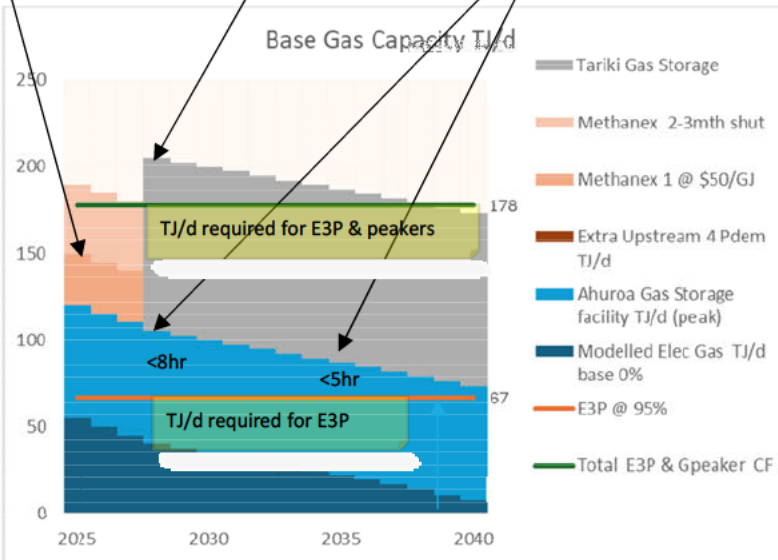
While Methanex remains, gas diverted to power generation at a high price

If Tariki is developed then gas peakers and E3P can run baseload all day without restriction.

Without Tariki then gas peakers would be restricted to < 8hrs per day in 2028 and <5hrs / day by 2035







10% of 2C contingent gas might be developed post 2028 , but this is not relied upon in base case.

If Methanex remains in 2028, then it will reduce the surplus available to be "shifted" forward, but will provide additional gas deliverability for power by diversion in dry years, albeit at a higher price.

Gas supply for power generation can also be restricted when Ahuroa gas storage is empty. Tariki would increase the storage from 7PJ to 17PJ.

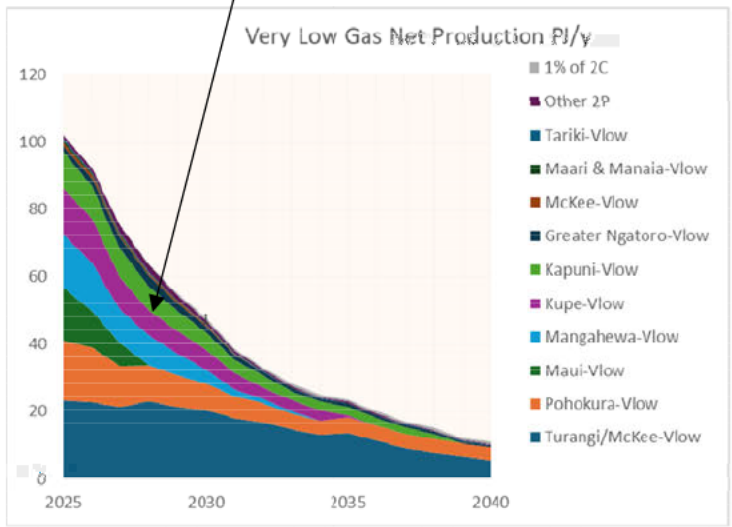
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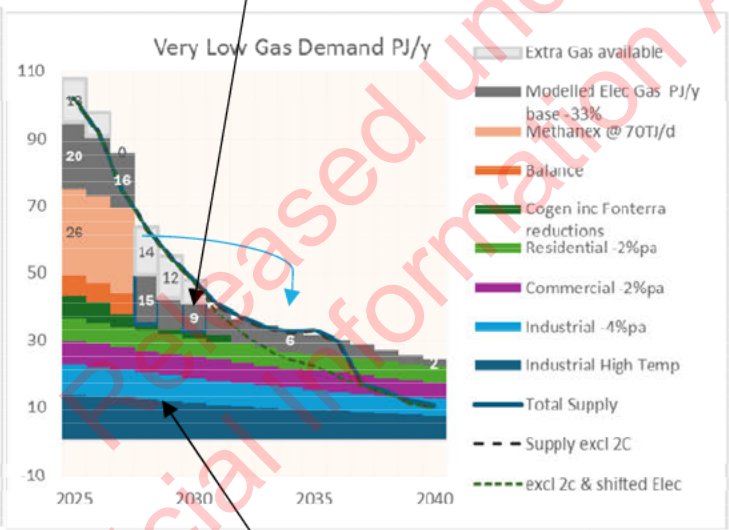
We also considered a very low gas supply scenario

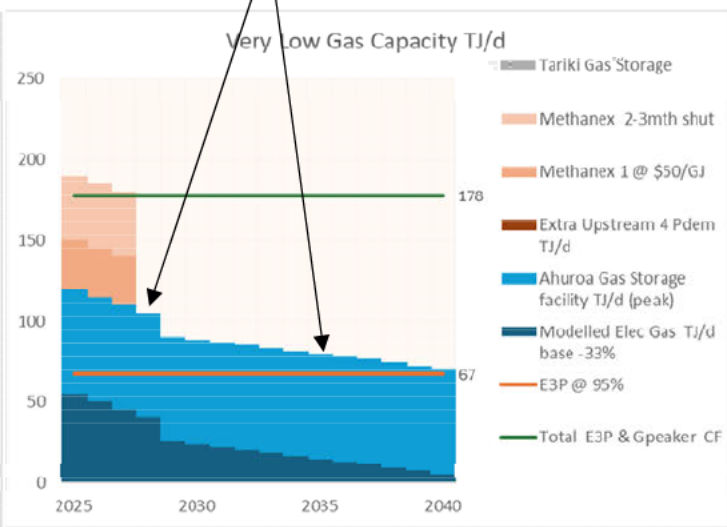
Supply scaled to Very low supply scenario. No 2C contingent gas is developed post 2028

Very low assumptions for upstream gas are 2/3 the base case. Relies on additional gas available in 2028 to 2030, to be carried forward to 2035.

Very low assumptions without Tariki imply peakers and E3P can't operate at base load for whole day so dry year cover and peaking is reduced. Gas peakers can only operate <8hr/d in 2028, reducing to <2hr/d by 2035







In this scenario it is assumed there is a gradual reduction in Industrial high temp gas demand .

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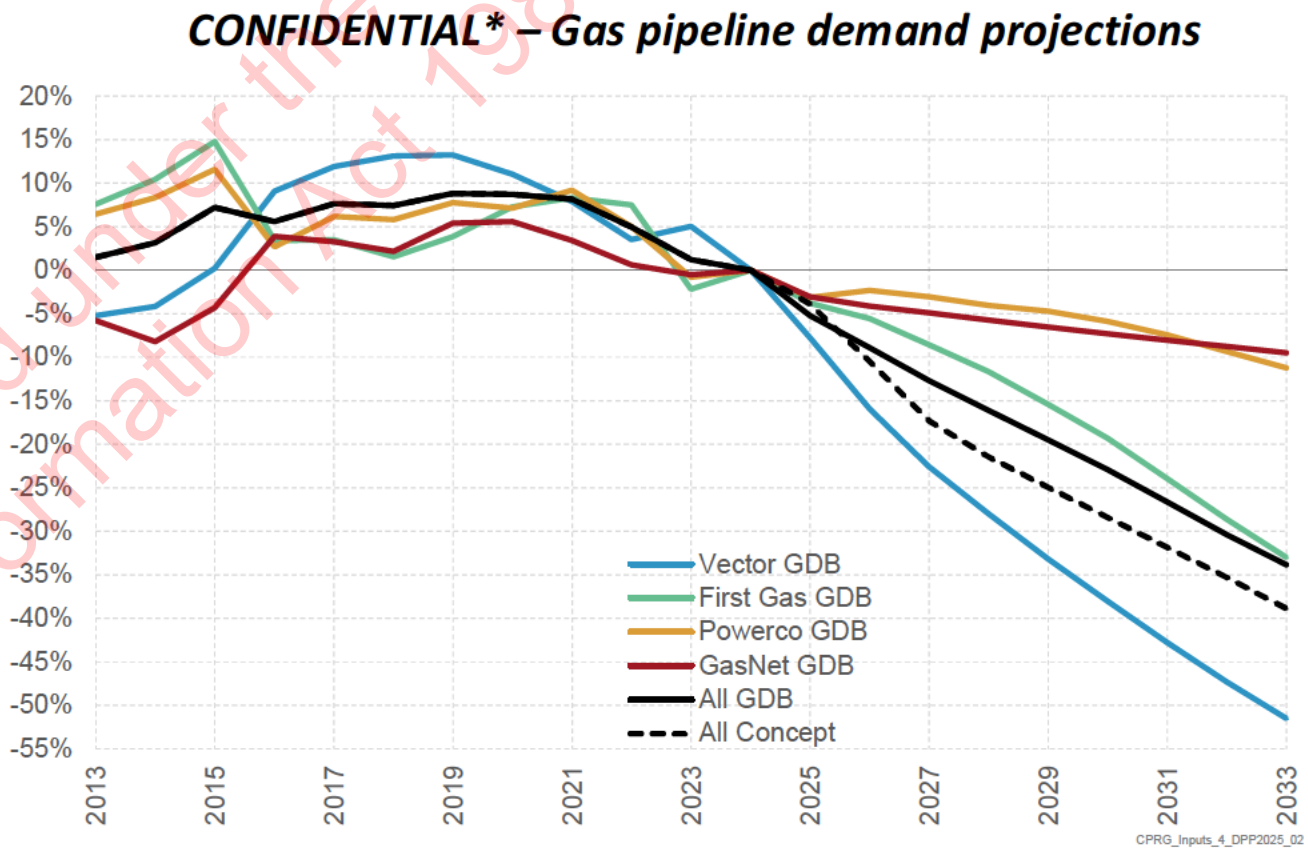
How have the upstream fuel deliverability assumptions been arrived at?

- Upstream fuel deliverability assumptions were chosen to be broadly consistent with the gas production profiles provided by MBIE
- The MBIE profiles cover all gas production, whereas the model 'only' takes account of assumed gas available for supply for power generation – treated as a contracted baseload take-or-pay amount in the model.
- The model dynamically models the injection of gas into storage (if the take-or-pay supply is greater than the on-the-day demand for gas for power generation) and extraction (if the take-or-pay supply is less than the on-the-day demand for gas for power generation)
- If gas storage is depleted, the model can call upon Methanex diversion – if Methanex is assumed to still be operating – but cannot call upon increased gas supply from upstream sources. As indicated in an earlier slide this is likely a conservative assumption (particularly for the 2028 scenarios) given the projection of demand from other gas users relative to the MBIE projected supply
- Not assuming higher levels of contracted gas supply is also to try and reflect the fact that power generators generally contract via take-or-pay arrangements, and contracting for too much gas will result in significant penalties from having to turn-away gas at times when power generation demand is low but gas storage is already full

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The gas pipeline businesses are projecting faster rates of non-powergen demand reduction than illustrated in the previous slides

- Concept has recently completed some gas demand projection work for the Commerce Commission which, among other things, reviewed the projections from the three main gas pipeline companies.
- This graph shows the projections from the GDBs, with the weighted average indicated by the 'All GDB' line.
- The pipelines are projecting a 35% reduction in demand by 2033 relative to 2024



* This data is due to be published by the Commerce Commission at the end of November. Until that time, this graph cannot be published by MBIE

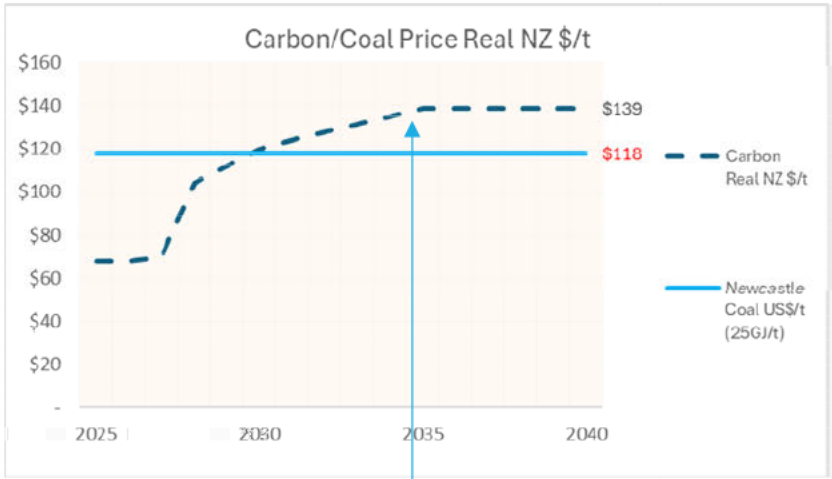
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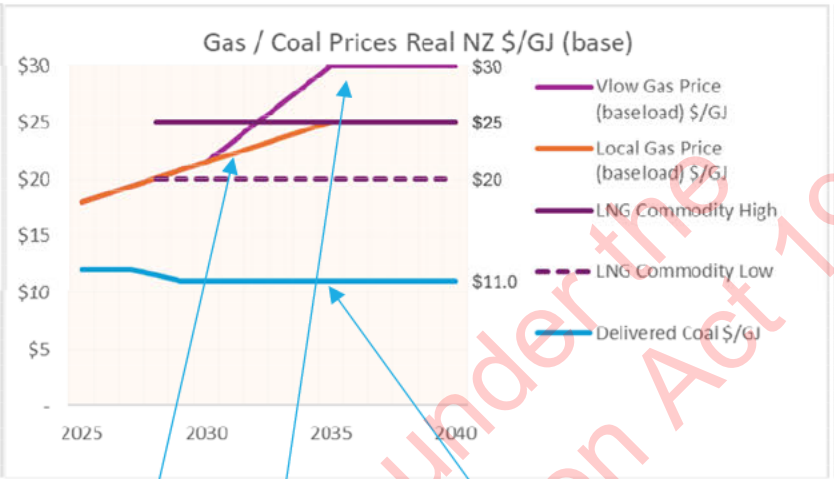
Fuel price assumptions

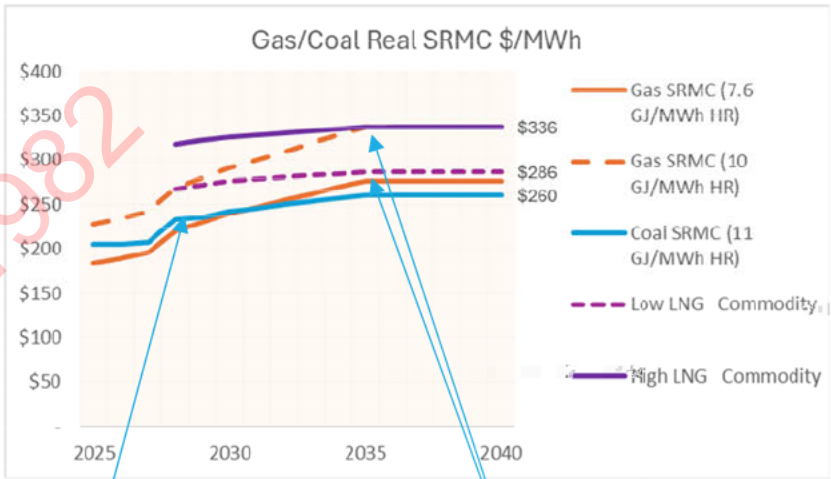
- Fuel prices were exogenously specified, as per graphs on next page
- The relative prices of NZ gas and LNG gas have a significant effect on whether LNG delivers net benefits or net costs.
  - If the price of LNG is relatively low (or less than) compared with the price of NZ gas, LNG will be more likely to give a net benefit
  - If LNG is significantly higher priced than NZ gas, LNG will likely result in cost
  - There is uncertainty in how LNG could impact domestic gas prices.
    - We've tested a sensitivity with higher gas prices for 2028 and 2030 with LNG. This assumes limited local gas supply competition (or development in future gas supply reduces) with domestic gas supply priced up to LNG prices (even in periods when LNG is not being used).
    - On the other hand, if there is a very competitive market for NZ gas supply, competition should reduce the ability to raise prices with LNG only setting the price when used. We refer to this as our 'split gas' market scenario.
    - We've tested both these scenarios.
- There is material uncertainty over future LNG prices due to a number of factors:
  - Uncertainty of the price of securing spot LNG and bringing it to NZ waters when needed
  - Uncertainty around the fixed costs of NZ infrastructure and the PJ/yr throughput of LNG. High fixed costs but low LNG throughput will lead to a high LNG infrastructure cost component of LNG price, and vice versa.
  - We've run $25/GJ and $20/GJ LNG price scenarios. These don't explicitly assume such prices cover the costs of NZ LNG infrastructure. If such costs were to be recovered through LNG prices, these could be significant if LNG throughput is low. Eg, $50m/yr fixed cost recovery spread over an average 1PJ/yr throughput = $50/GJ

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Fuel Price Assumptions







Carbon price assumption higher than previous runs done in September.

Local gas prices are assumed to rise towards LNG in this constrained scenario.

NOTE: It is possible gas prices in the no LNG scenario may be lower than this for longer – particularly if a 'managed transition' away from gas were to occur.

In the Vlow case local gas prices are assumed to rise towards to $30/GJ reflecting the cost of diversion from other gas uses

Concept delivered coal assumption of $11/GJ , is consistent with $US 118/t Newcastle coal + NZ $80/t coal handling/transport . This is lower than the HFO price formula which includes $145/t transport & handling cost.

NOTE: It is hard to know what the 'true' cost to Genesis is.

Base SRMCs indicate that Coal SRMC is very close to Gas at E3P. Gas peaker SRMC are above EP3 and Coal.

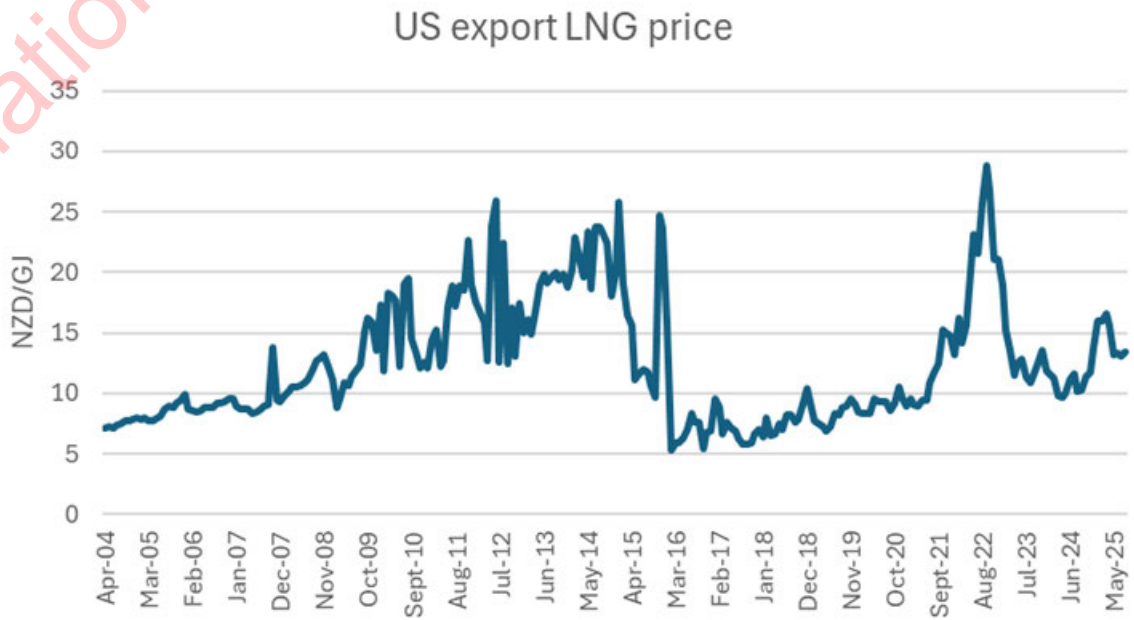
Gas constraints will add a premium to dispatch prices.

LNG gas plant are assumed unconstrained and offered at Commodity SRMCs based on either $20/GJ or $25/GJ

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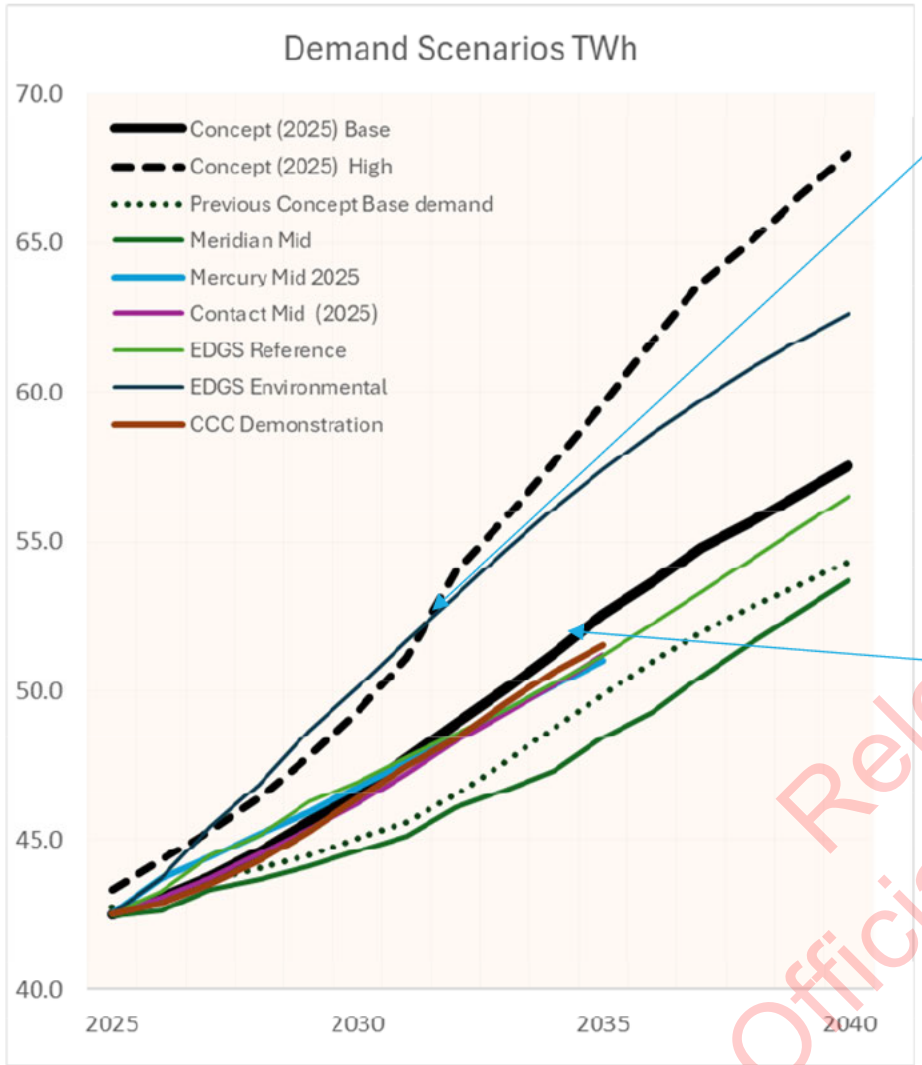
Linkage to international LNG prices

- The New Zealand electricity system is relatively insulated from international energy markets.
  - Our main links currently are imported oil, imported Indonesian coal and methanol export
- This was beneficial during the “Global energy crisis” of 2021-2023 when international energy prices (particularly LNG) spiked, but New Zealand was relatively unaffected
- Relying on imported LNG would significantly increase this dependence on international energy prices.
- The modelling has not considered the potential impact of international fuel price volatility



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Electricity Demand

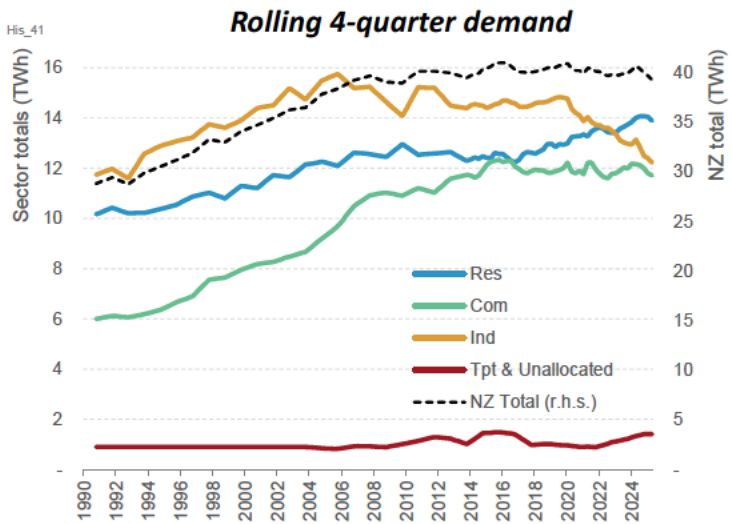


Concept's high demand case includes high EV & Process heat & Date centres rising to 176MW (2030) and 380MW (2035)

Concept new base case is higher than previous runs. Includes Data centres rising to 146MW in 2030 and 300MW in 2035.

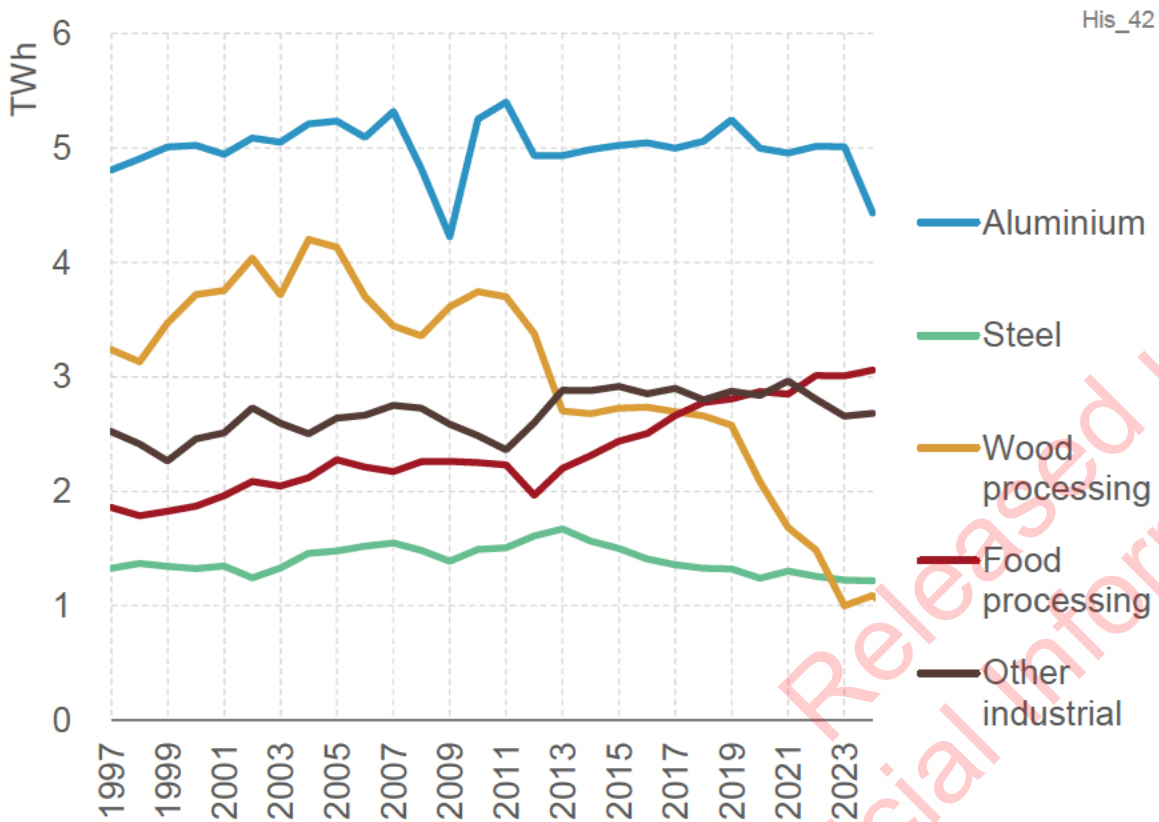
This demand includes both rooftop solar and transmission losses.

- Concept demand projections are higher than earlier projections – particularly through higher assumed uptake of data centres
- However, it should be noted that the projected increase in demand has yet to start
  - Concept projection for 2025 is for 1.3% demand growth. (Other forecasters projecting even greater growth)
  - However, Total NZ demand for YE Sep-25 is 1.3% *lower* than YE Sep-24 (0.9% lower correcting for Tiwai demand response) (Source: EA data)
  - MBIE data shows a slow-down in Residential demand for YE Jun-25



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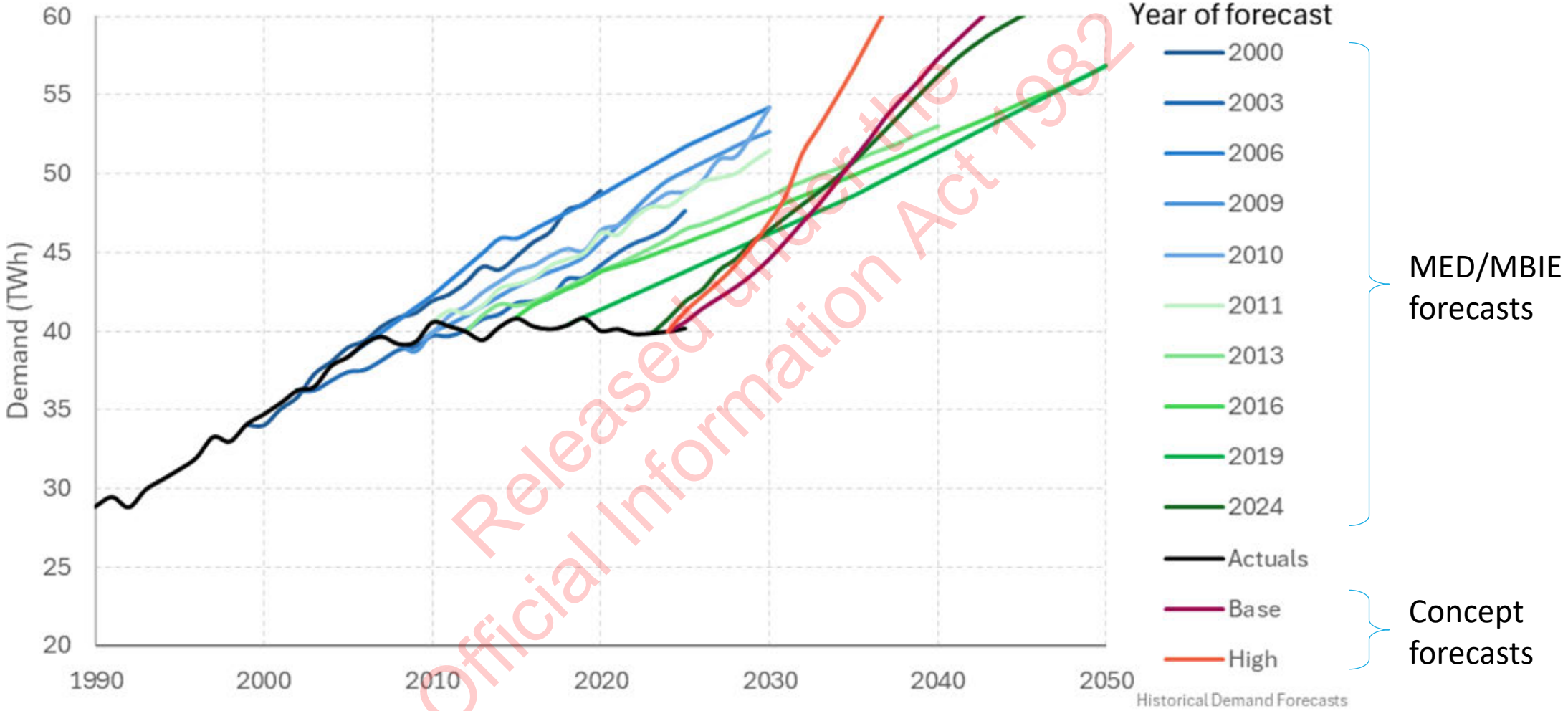
Industrial demand reduction has almost entirely been in wood processing



- Wood processing electricity demand has been declining since 2005
  - Largely due to global supply / demand dynamics
  - Accelerated in recent years due to NZ energy scarcity
- 2024 reduction in Aluminium demand is temporary, due to demand reduction contract being called in tail end of Winter 2024 scarcity situation

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Historically, demand has proven particularly challenging to forecast



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Generation development

- Winter 2024 was particularly bad because a dry winter occurred during a period when the % of renewable generation was relatively low AND gas supply for thermal generation was very constrained AND there were question marks over the ability of Huntly to sustain three Rankines on coal
- A system with a much higher % of renewables would significantly reduce the amount of thermal generation required
- Similarly, a system with three coal-fired Rankines would significantly reduce the amount of that thermal generation required by gas-fired plant – particularly during dry periods
- Scenarios developed to test the sensitivity of outcomes to variations in these factors

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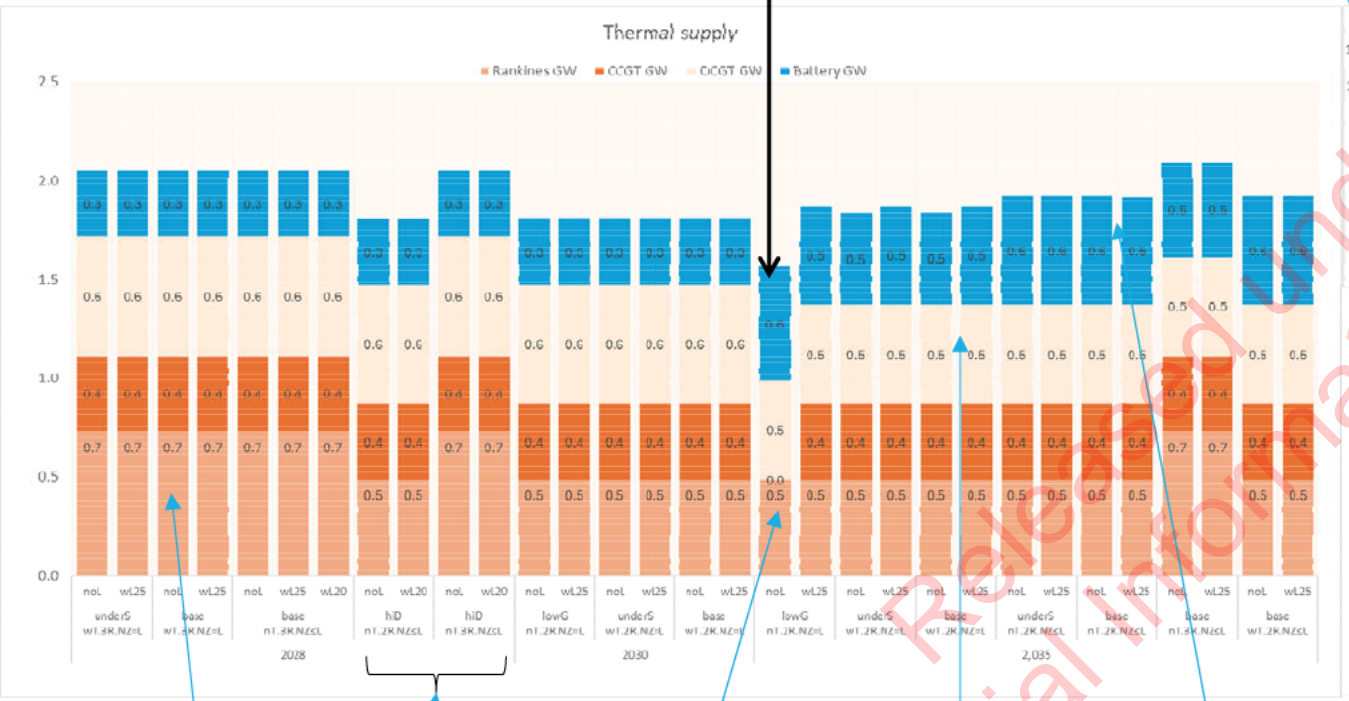
Generation development

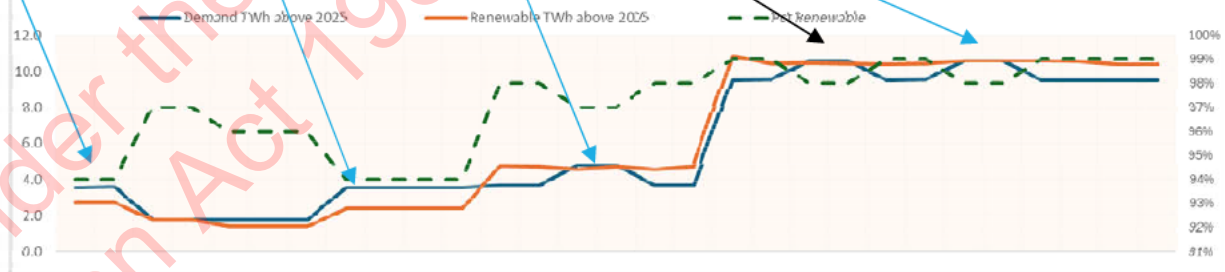
Extra Bess to account for loss of E3P MW.
It would also be possible to "replace" E3P by extending use of 3rd Rankine to 2035.

In 2028 under supply has high demand and "likely" build

In 2028 high demand has only committed build

Under supply has plant to meet base demand, but demand always turns out to be higher by 1 yr's growth







3 Rankines on coal are assumed in 2028, but this drops to 2R post 2030 by assumption.

The greatest stress cases have high demand and only committed build in 2028, modelled with2 or 3 Rankines.

E3P is retired in the Vlow gas scenario as there is insufficient gas and local gas prices are high and flexible response is highly valued .

In 2035 it is assumed that 100MW of peakers are retired – due to age or extended outage

2hr to 10hr duration batteries are installed when economic.

In 2028 under supply has high demand and a conservative 'likely' build

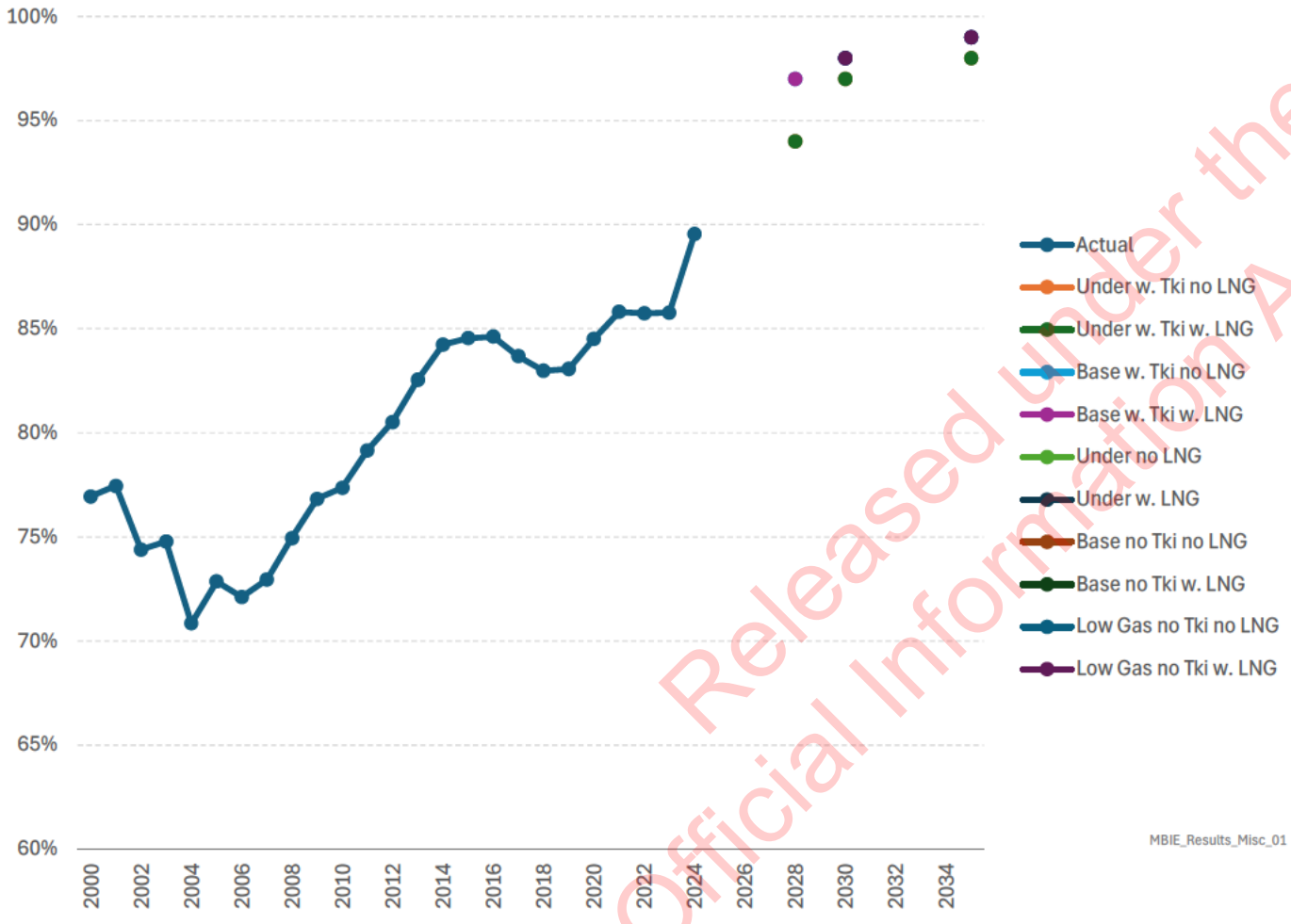
In 2028 base has base demand and a conservative committed build

In 2028 high demand with conservative committed build

The system is optimised to 2030/35 demand in the base case, under supply assumes an extra 1 year demand growth occurs by then.

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% renewables projected to significantly increase – resulting in a significant decline in the need for thermal generation and fuel



Note:

- Actual is on a mean hydrology basis (ie, correcting for whether the year was relatively wet or dry) to be consistent with projected future years.
- % renewables calculated on an ex-cogen basis

Note: Lots of the dots are on top of each other for the projections

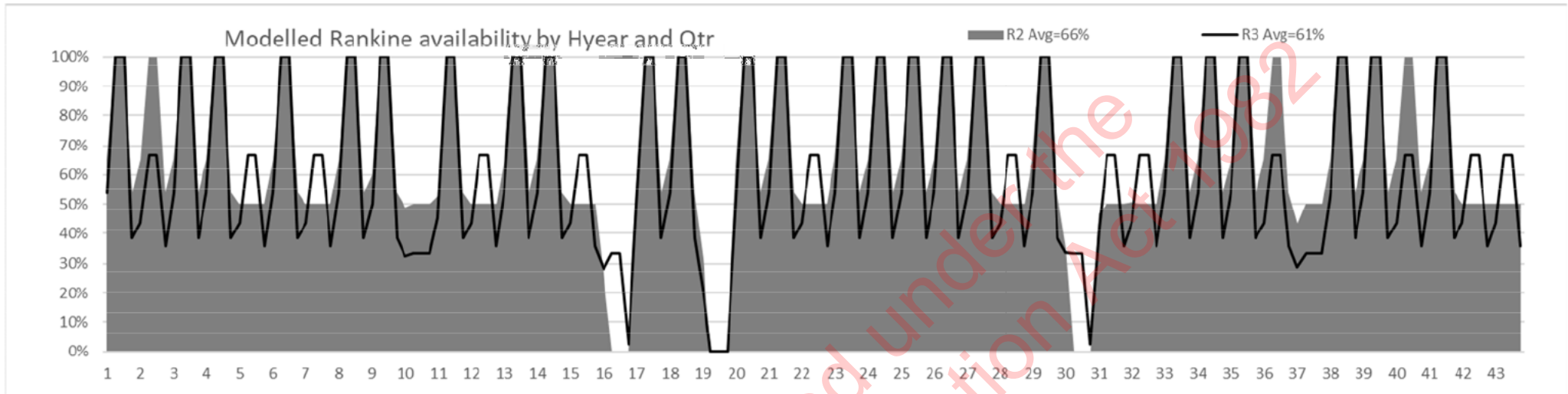
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Thermal plant availability (particularly Rankines) has material effect on need for alternative resources such as LNG

- Modelling seeks to reflect the potential for thermal units to be out due to failure, including for extended periods (as has occurred at times in the past).
  - Rankine availability also constrained in summer due to river heating constraints
- Rankine outages will particularly drive the need for LNG
- The following slide shows assumed major thermal plant outages – common outage pattern across weather years for all scenarios
- Scale and duration of outages is considered on pessimistic side – likely over-estimating the need for alternative resources such as LNG

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The modelling includes conservative random sampling of significant thermal outages



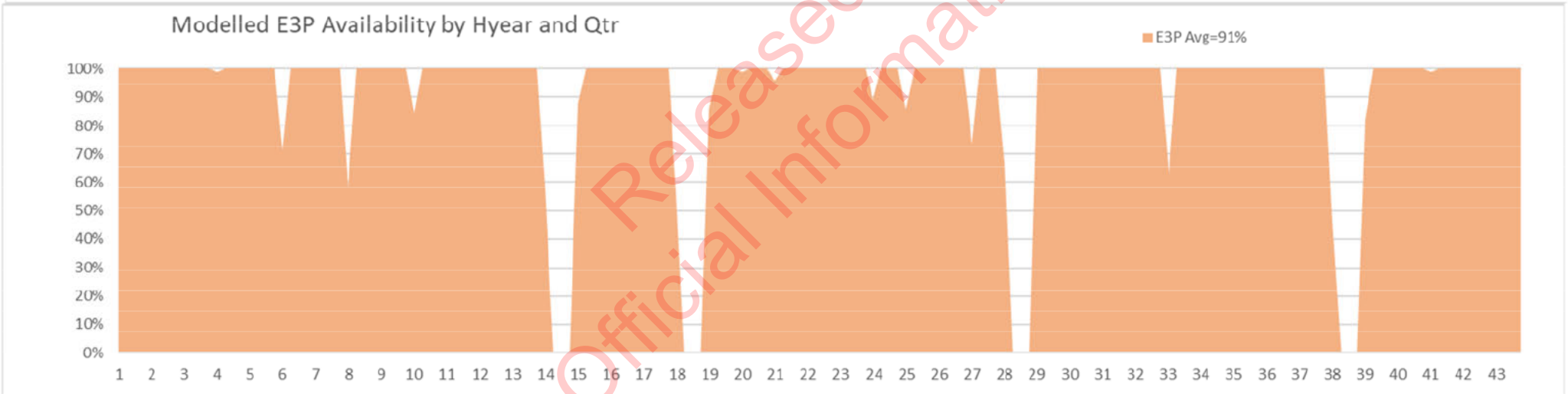


Chart shows modelled availability for 2 and 3 Rankine cases. There are 2 full outages lasting 2-3 quarters , and around 8 single unit outages over 43 years.

This is conservative assumption partly accounts for the risks that Rankine units may not be contracted by the market.

Note summer derating for river constraints is included

Modelling of E3P includes 4 full outages lasting 2-3 quarters.

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Scenario terminology

- The scenario IDs in the various results charts and tables can be interpreted as follows:
  - ‘Base’ indicates that both the renewable supply / demand balance, and NZ gas deliverability are as per the respective base assumptions
  - hiD indicates a 2028 scenario with only committed renewable build and high demand
  - underS indicates an under-supply of renewables
  - lowG indicates low NZ gas deliverability
  - The following elements in the suffix string are as follows:
    - wT or nT = with Tariki or no Tariki, respectively
    - 2R or 3R = 2 Rankines or 3 Rankines, respectively
    - NZ=L or NZ≤L = NZ gas price is set to LNG gas price, or a split gas market, respectively
    - nL, wL25, and wL20 = no LNG, with LNG priced at either $25/GJ or $20/GJ

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Scenario definition – reference table

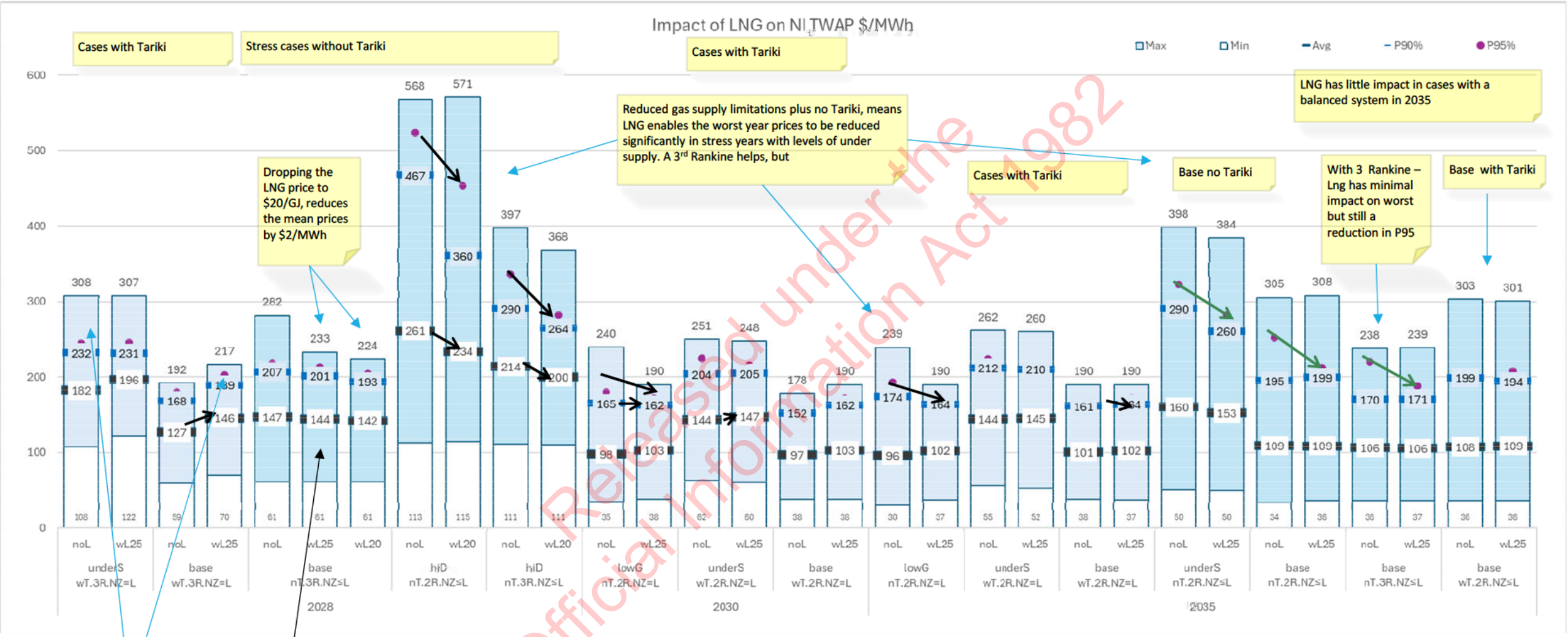
	Run Num	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
	Model year	2028											2030						2,035													
	State of World	underS wT.3R.NZ=L		base wT.3R.NZ=L		base nT.3R.NZ≤L			hiD nT.2R.NZ≤L		hiD nT.3R.NZ≤L		lowG nT.2R.NZ=L		underS wT.2R.NZ=L		base wT.2R.NZ=L		lowG nT.2R.NZ=L		underS wT.2R.NZ=L		base wT.2R.NZ=L		underS nT.2R.NZ≤L		base nT.2R.NZ≤L		base nT.3R.NZ ≤L		base wT.2R.NZ ≤L	
		noL	wL25	noL	wL25	noL	wL25	wL20	noL	wL25	noL	wL20	noL	wL25	noL	wL25	noL	wL25	noL	wL25	noL	wL25	noL	wL25	noL	wL25	noL	wL25	noL	wL25	noL	wL25
Demand		base		base		base			high		high		base		base		base		base		base		base		base		base		base		base	
43	Demand TWh	46.1	46.1	44.3	44.3	44.3	44.3	44.3	46.0	46.0	46.0	46.0	46.2	46.2	47.3	47.3	46.2	46.2	52.0	52.0	53.1	53.1	52.0	52.0	53.1	53.1	52.0	52.0	52.0	52.0	52.0	52.0
	Generation	45.9	46.0	44.2	44.2	44.1	44.1	44.1	45.9	45.9	45.9	45.9	46.1	46.2	47.3	47.3	46.1	46.2	52.0	52.0	53.1	53.1	52.0	52.0	53.1	53.1	52.0	52.0	52.0	52.0	52.0	52.0
Gas																																
	Upstream PJ/y	14.6	unlimited	14.6	unlimited	14.6	unlimited	unlimited	14.6	unlimited	14.6	unlimited	8.4	unlimited	12.4	unlimited	12.4	unlimited	5.1	unlimited	7.7	unlimited	7.7	unlimited	7.7	unlimited	7.7	unlimited	7.7	unlimited	7.7	unlimited
	Tariki Storage	yes	unlimited	yes	unlimited	no	unlimited	unlimited	yes	unlimited	yes	unlimited	yes	unlimited	yes	unlimited	yes	unlimited	yes	unlimited	yes	unlimited	yes	unlimited	yes	unlimited	yes	unlimited	yes	unlimited	yes	unlimited
	UGS PJ	17.0	unlimited	17.0	unlimited	7.0	unlimited	unlimited	7.0	unlimited	7.0	unlimited	7.0	unlimited	17.0	unlimited	17.0	unlimited	7.0	unlimited	17.0	unlimited	17.0	unlimited	7.0	unlimited	7.0	unlimited	7.0	unlimited	17.0	unlimited
	Base Gas/LNG Price	$20.1	$25.0	$20.1	$25.0	$20.1	$20.1	$20.1	$20.1	$20.1	$20.1	$20.1	$21.5	$25.0	$21.5	$25.0	$21.5	$25.0	$30.0	$25.0	$25.0	$25.0	$25.0	$25.0	$25.0	$25.0	$25.0	$25.0	$25.0	$25.0	$25.0	$25.0
	Methanex /Balance exit in	2028	2028	2028	2028	2027	2027	2028	2028	2028	2028	2027	2027	2028	2028	2028	2028	2028	2028	2028	2028	2028	2028	2028	2028	2028	2028	2029	2030	2031	2030	2031
	Split gas market		no		no		yes		no		no		no		no		no		no		yes		yes		yes		yes	yes	yes	yes	yes	yes
Prices	Carbon $/t	$104.0	$104.0	$104.0	$104.0	$104.0	$104.0	$104.0	$104.0	$104.0	$104.0	$104.0	$120.0	$120.0	$120.0	$120.0	$120.0	$120.0	$139.0	$139.0	$139.0	$139.0	$139.0	$139.0	$139.0	$139.0	$139.0	$139.0	$139.0	$139.0	$139.0	$139.0
	Coal $/GJ	$11.5	$11.5	$11.5	$11.5	$11.5	$11.5	$11.5	$11.5	$11.5	$11.5	$11.5	$11.5	$11.5	$11.5	$11.5	$11.5	$11.5	$11.5	$11.5	$11.5	$11.5	$11.5	$11.5	$11.5	$11.5	$11.5	$11.5	$11.5	$11.5	$11.5	$11.5
	Oil $/GJ	$50.0	$50.0	$50.0	$50.0	$50.0	$50.0	$50.0	$50.0	$50.0	$50.0	$50.0	$50.0	$50.0	$50.0	$50.0	$50.0	$50.0	$50.0	$50.0	$50.0	$50.0	$50.0	$50.0	$50.0	$50.0	$50.0	$50.0	$50.0	$50.0	$50.0	$50.0
Thermal supply	Rankines GW	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.5	0.5	0.7	0.7	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.7	0.7	0.5	0.5
	CCGT GW	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.0	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	OCGT GW	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
	Battery GW	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.6	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.5	0.5	0.5	0.6	0.6
Renewable Supply		Likely		Committed		Committed			Committed		Committed		Balanced		under		Balanced		Balanced		Balanced		Balanced		under		Balanced		Balanced		Balanced	
90%	Geo GW	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.4	1.4	1.4	1.4	1.4	1.4	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
40%	Wind GW	1.5	1.5	1.5	1.5	1.4	1.4	1.4	1.4	1.4	1.4	1.4	2.0	2.0	1.9	2.0	1.9	2.0	2.7	2.6	2.6	2.6	2.6	2.6	2.7	2.7	2.7	2.6	2.6	2.6	2.6	2.6
20%	Solar GW	1.6	1.6	1.0	1.0	1.0	1.0	1.0	1.6	1.6	1.6	1.6	1.0	1.1	1.0	1.1	1.0	1.1	1.4	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.4	1.3	1.3	1.3	1.4
14%	rSolar GW	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.6	0.6	0.6	0.6	0.6	0.6	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	Renewable GW	4.8	4.8	4.2	4.2	4.1	4.1	4.1	4.7	4.7	4.7	4.7	5.0	5.0	5.0	5.0	5.0	5.0	6.8	6.6	6.7	6.6	6.6	6.6	6.7	6.7	6.7	6.7	6.6	6.7	6.7	6.7
	Renewable TWh	19	19	18	18	17	17	17	18	18	18	18	21	21	21	21	21	21	27	27	27	27	26	27	27	27	27	27	26	26	27	27
	Pct Renewable	94%	94%	97%	97%	96%	96%	96%	94%	94%	94%	94%	98%	98%	97%	97%	98%	98%	99%	99%	98%	98%	99%	99%	98%	98%	99%	99%	99%	99%	99%	99%
Balance of Supply/Demand																																
	Demand TWh above 2025	3.6	3.6	1.8	1.8	1.8	1.8	1.8	3.5	3.5	3.5	3.5	3.7	3.7	4.8	4.8	3.7	3.7	9.5	9.5	10.6	10.6	9.5	9.5	10.6	10.6	9.5	9.5	9.5	9.5	9.5	9.5
16.1	Renewable TWh above 2025	2.7	2.7	1.8	1.8	1.4	1.4	1.4	2.4	2.4	2.4	2.4	4.7	4.7	4.5	4.7	4.5	4.7	10.8	10.4	10.4	10.4	10.4	10.4	10.6	10.6	10.6	10.5	10.4	10.4	10.5	10.5
Fixed Generation cost																																
	Rankines $/kW/y	$91	$91	$90	$91	$90	$90	$90	$91	$91	$91	$91	$90	$90	$90	$91	$90	$90	$91	$90	$91	$91	$90	$90	$90	$91	$90	$90	$90	$90	$90	$90
	E3P CCGT $/kW/yr	$35	$35	$34	$34	$34	$34	$34	$35	$34	$35	$34	$34	$34	$34	$34	$34	$34	#DIV/0!	$34	$34	$34	$34	$34	$34	$34	$34						
	Wind $/kW/y	$269	$269	$269	$269	$269	$269	$269	$269	$269	$269	$269	$254	$254	$254	$254	$254	$254	$229	$229	$229	$229	$229	$229	$229	$229	$229	$229	$229	$229	$229	$229
	Solar $/kW/y	$164	$164	$164	$164	$164	$164	$164	$164	$164	$164	$164	$150	$150	$150	$150	$150	$150	$125	$125	$125	$125	$125	$125	$125	$125	$125	$125	$125	$125	$125	$125
	New OCGT $/kW/y	$245	$245	$245	$245	$245	$245	$245	$245	$245	$245	$245	$190	$190	$190	$190	$190	$190	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182	$182

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Results of modelling

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Impact of LNG on time-weighted NI Prices over weather years



LNG is likely to increase average electricity prices in the short term

But with split market , Lng enables the worst prices to be reduced

In the worst 2028 stress case with significant under supply and no Tariki,

Mean prices rise or fall slightly depending on relative cost of LNG and local gas

P90 prices are only slightly reduced in stress years

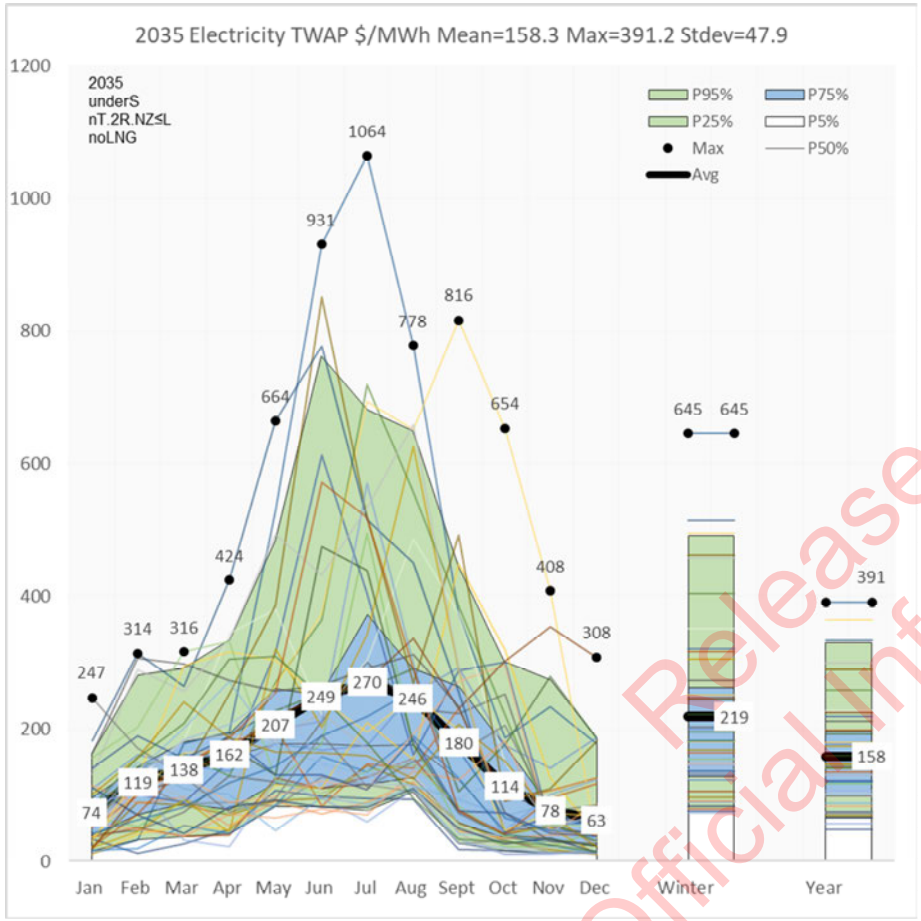
With split market in 2035 Lng has minor impact on mean prices, but can reduce worst case and P95 prices in a under supply year

Note: The runs which include the split market gas modelling for LNG are indicated by the slightly darker blue. These runs also include a different random sampling for major thermal outages, and so they can't be exactly compared other runs.

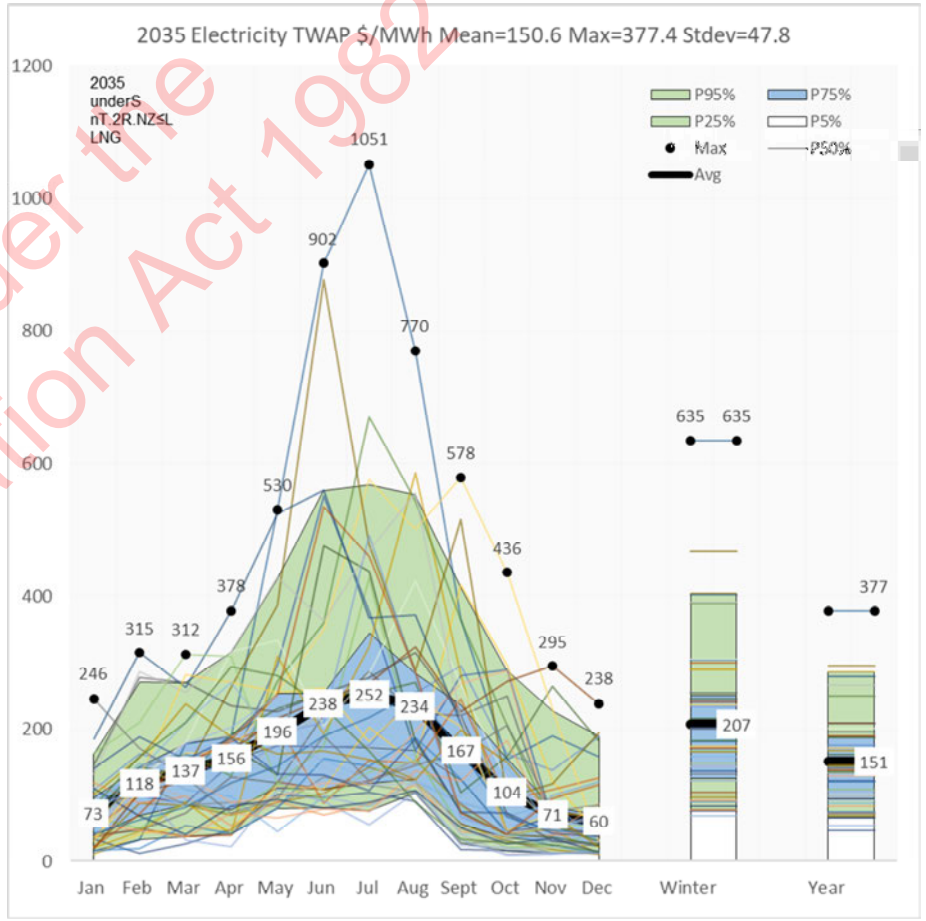
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Monthly distribution of TWAP for 2035 under supply, no Tariki, only 2 Rankines, split gas market: with and without LNG

No LNG



With LNG

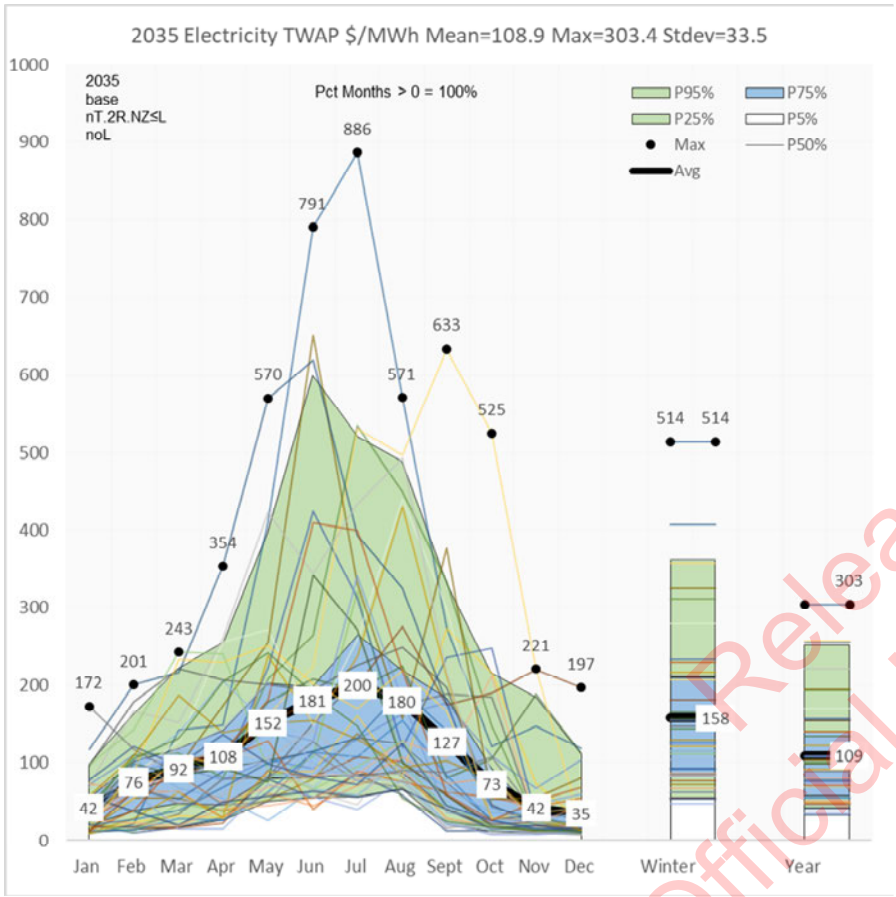


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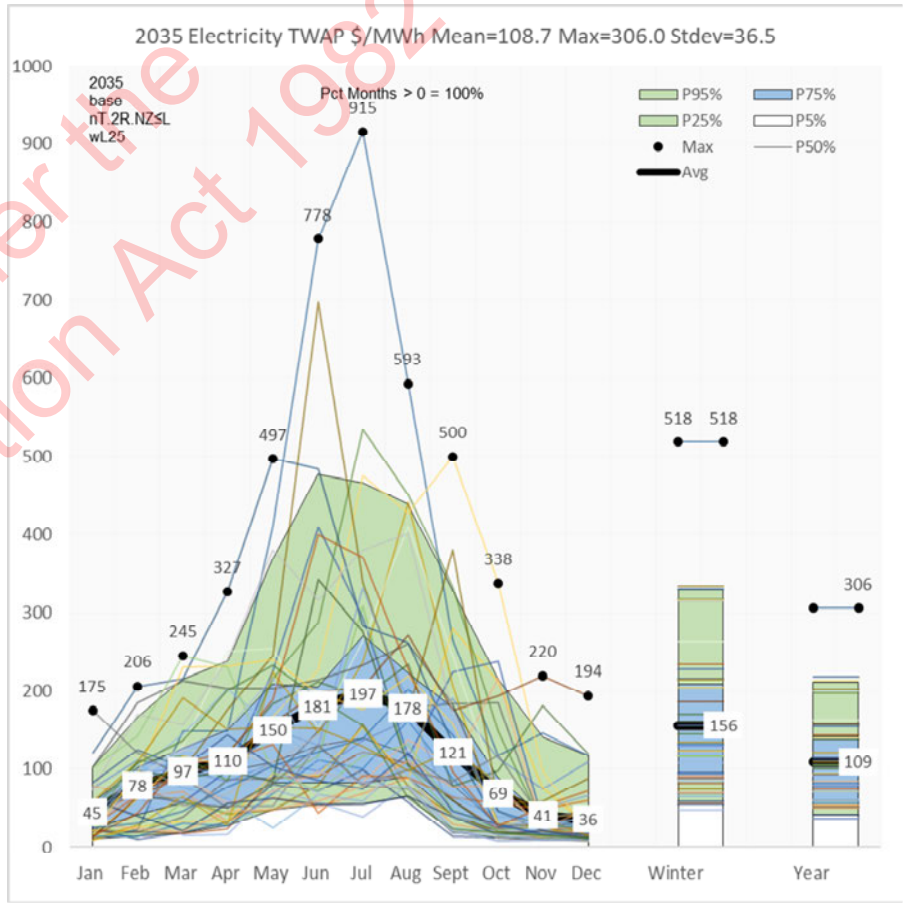
- LNG reduces, but does not eliminate, high prices in the driest inflow sequences in this stressed market scenario

Monthly distribution of TWAP for 2035 balanced supply/demand, no Tariki, 2 Rankines, split gas market: with and without LNG

No LNG



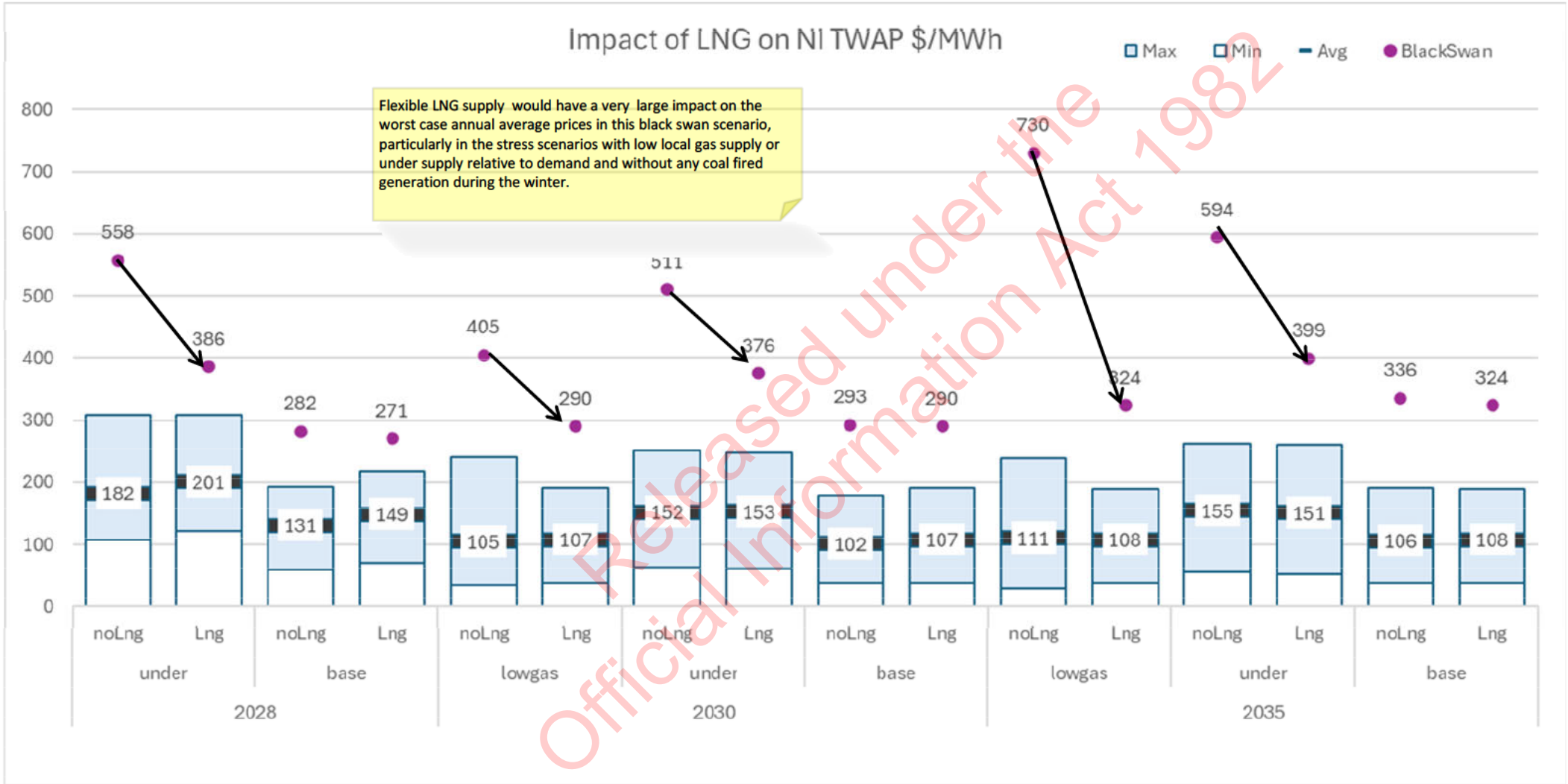
With LNG



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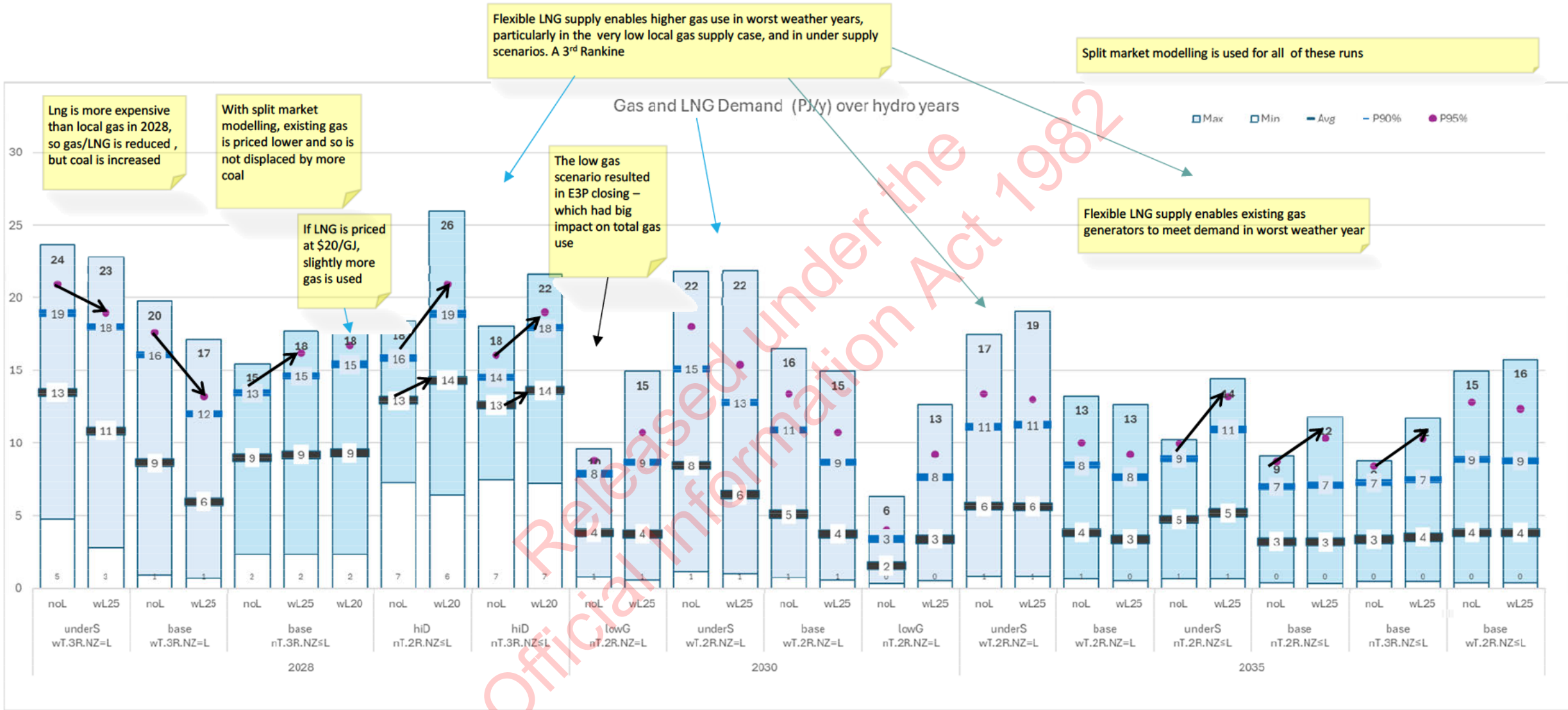
- LNG reduces price volatility at P95, but does not eliminate, high prices in the driest inflow sequences in this better-resourced market scenario

We have also explored an extreme black swan scenario (a low hydro year and all Rankine units out over winter)



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Gas + LNG demand PJ/y over weather years



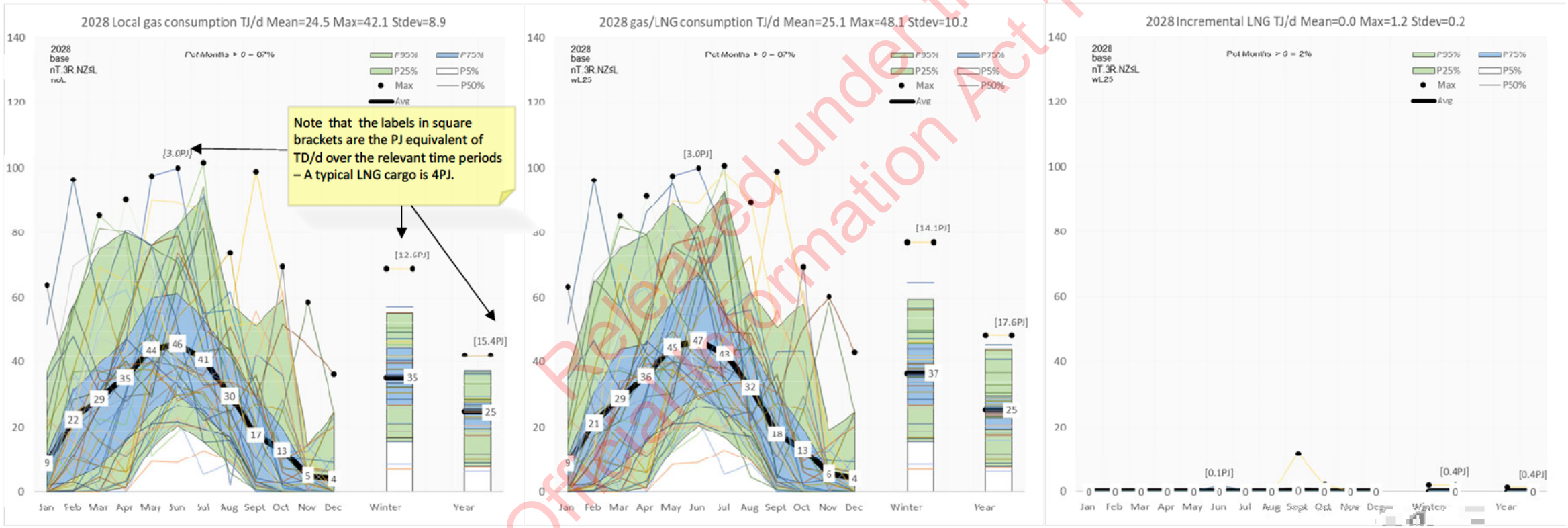
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Monthly Gas usage with and without LNG for 2028 base supply, no Tariki, 2 Rankines, split gas market

Note the very strongly seasonal demand profile for gas or LNG and the very large variability over the whole year and for the winter period. There are sequences of several months where demand exceeds 80-100TJ/d on average.

In this scenario – there is only 2% of months in which a combination of local gas and 3 Rankines is in sufficient to meet the demand of 43 weather years.

There would be a more significant need for LNG "top up" in a more stressed under-supply scenario with more than base demand .



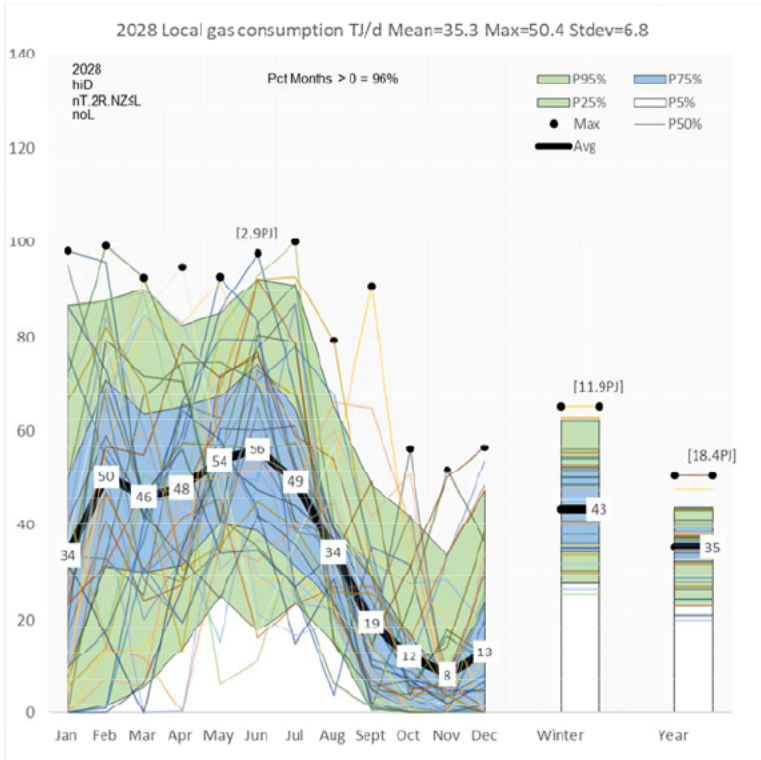
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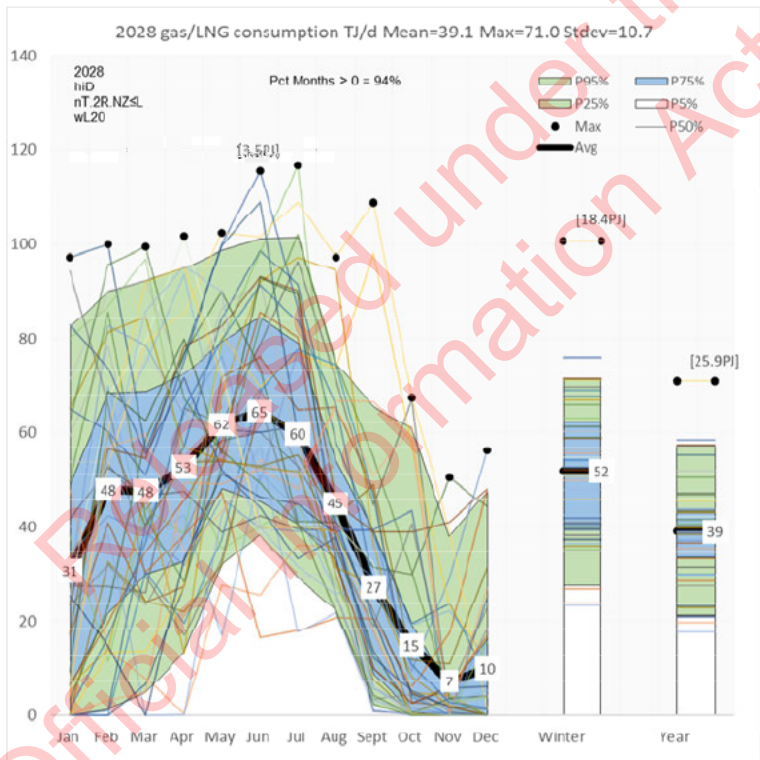
Monthly Gas usage with and without LNG for 2028 Hi Demand, no Tariki, 2 Rankines, split gas market

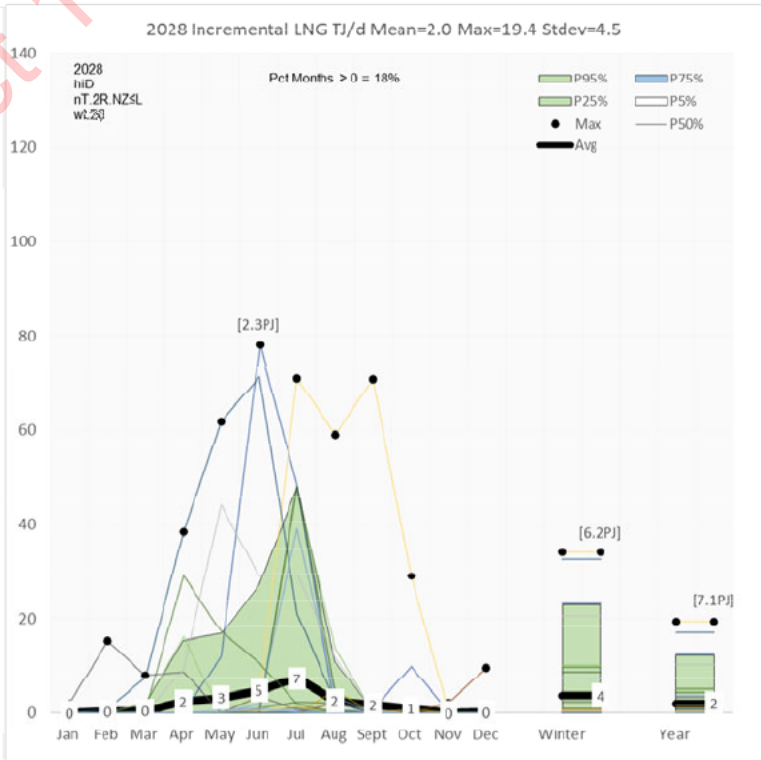
Note the very strongly seasonal demand profile for gas or LNG and the very large variability over the whole year and for the winter period. There are sequences of several months where demand exceeds 100TJ/d on average.

In this scenario with high demand and 2 Rankine

– there are around 20% of the months in which a combination of local gas and 3 Rankines is insufficient to meet the demand of 43 weather years.







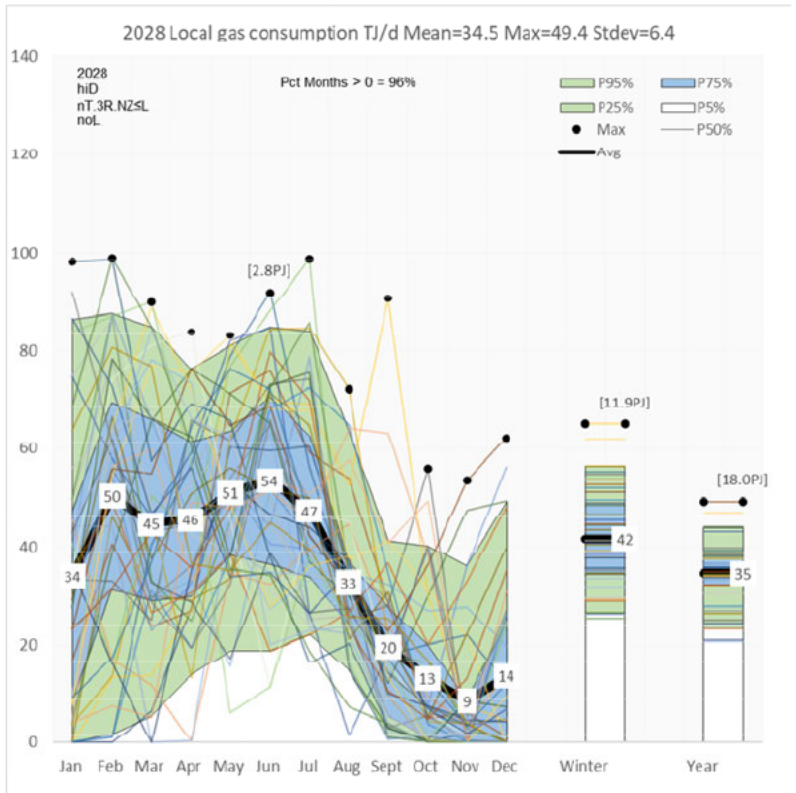
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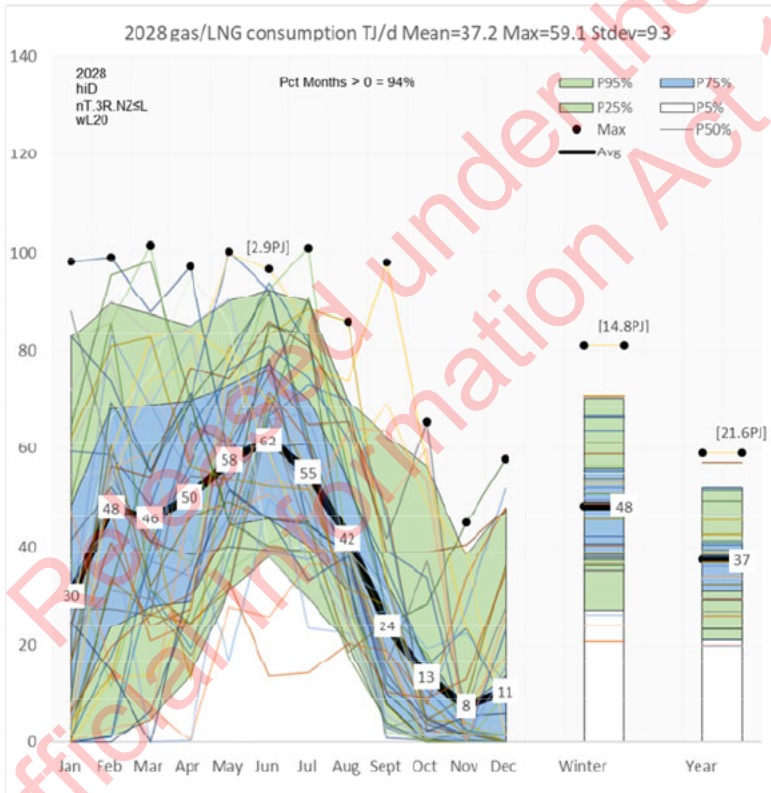
Monthly Gas usage with and without LNG for 2028 Hi Demand, no Tariki, 3 Rankines, split gas market

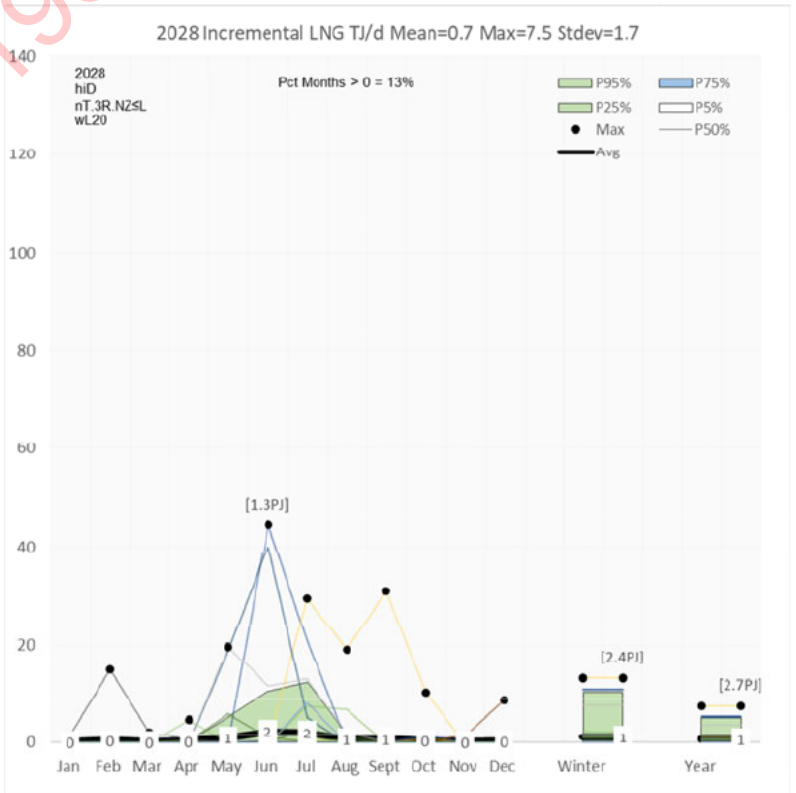
Note the very strongly seasonal demand profile for gas or LNG and the very large variability over the whole year and for the winter period. There are sequences of several months where demand exceeds 100TJ/d on average.

In this scenario with high demand and 3 Rankine

– there are around 13% of the months in which a combination of local gas and 3 Rankines is insufficient to meet the demand of 43 weather years.

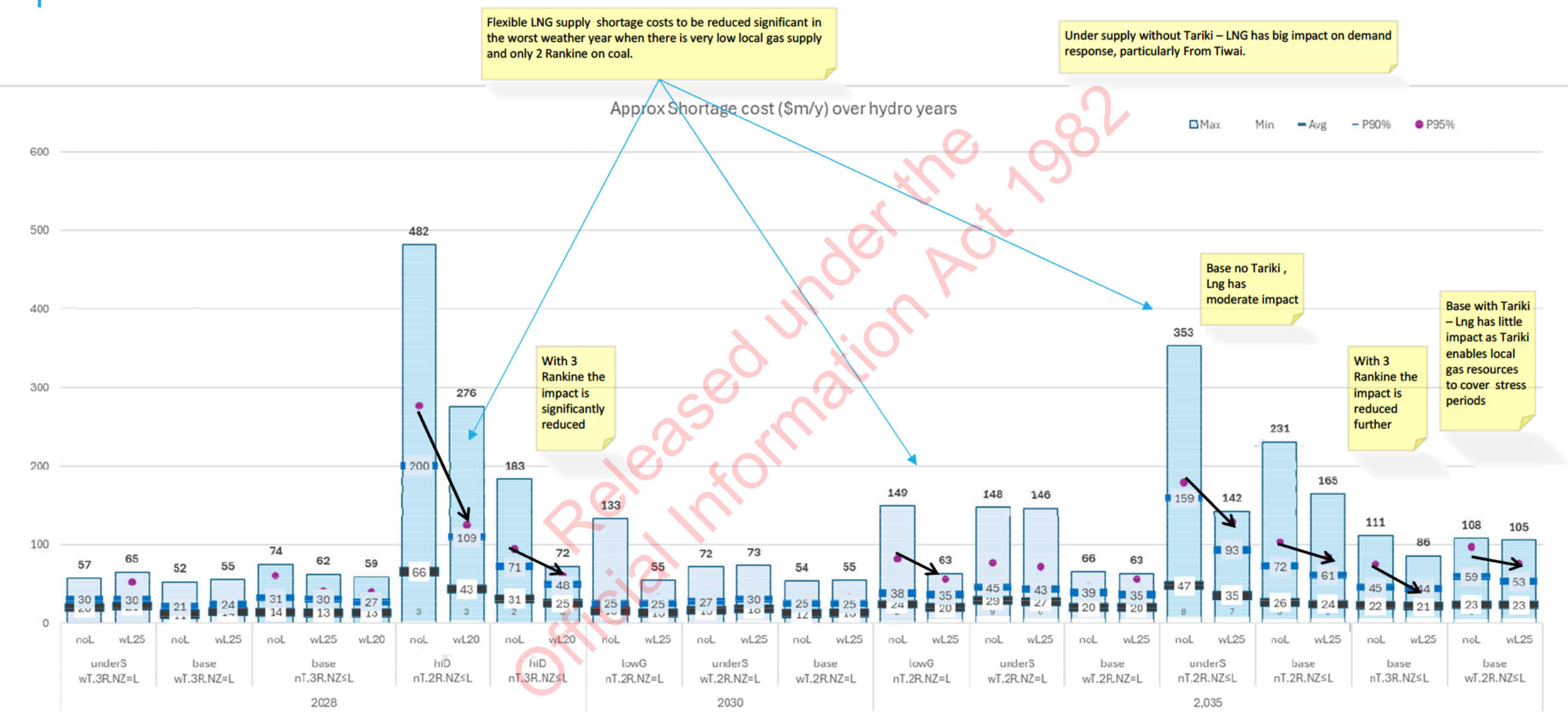






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Impact of LNG on Shortage cost (Tiwai & other DR) over weather – years

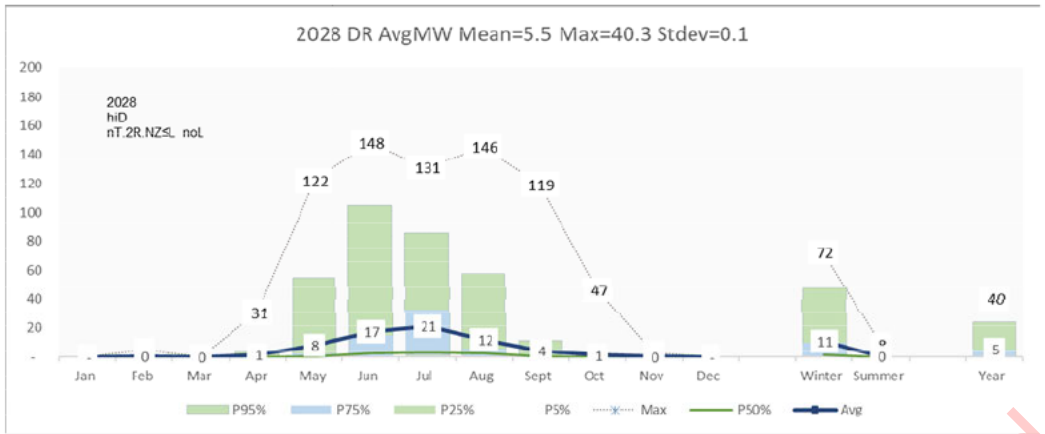


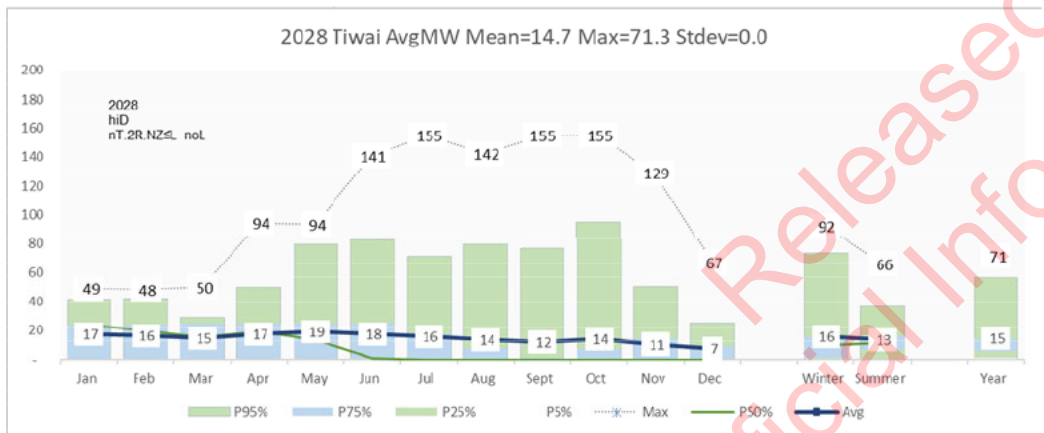
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Note: The approx. shortage costs in this chart are estimated on the basis of an annual fixed average cost for Tiwai and other demand response cost multiplied by GWh of shortage. In reality the cost will vary according to the hours in each tranche. The runs which include the split market gas modelling for LNG are indicated by the slightly darker blue. These runs also include a different random sampling for major thermal outages, and so they cant be exactly compared other runs. However

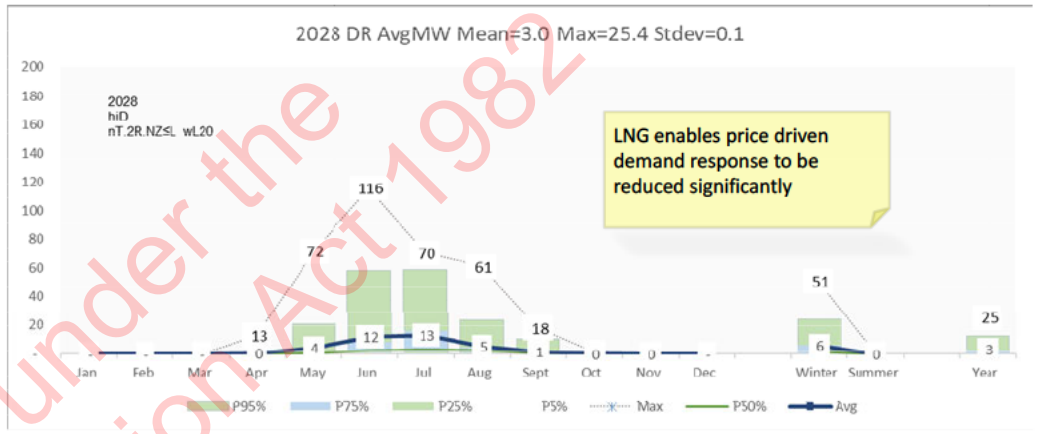
Shortage for 2028 stressed scenario (high demand, no Tariki, only 2 Rankines), split gas market: with and without LNG

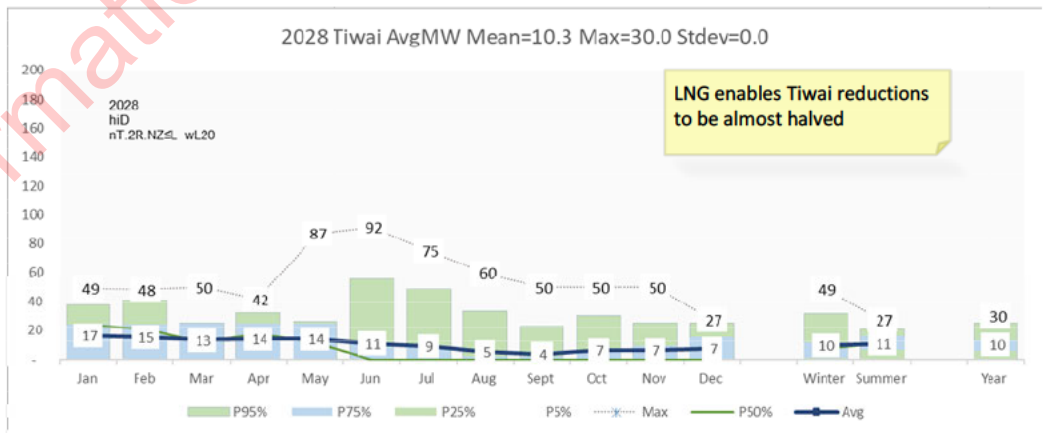
No LNG





With LNG

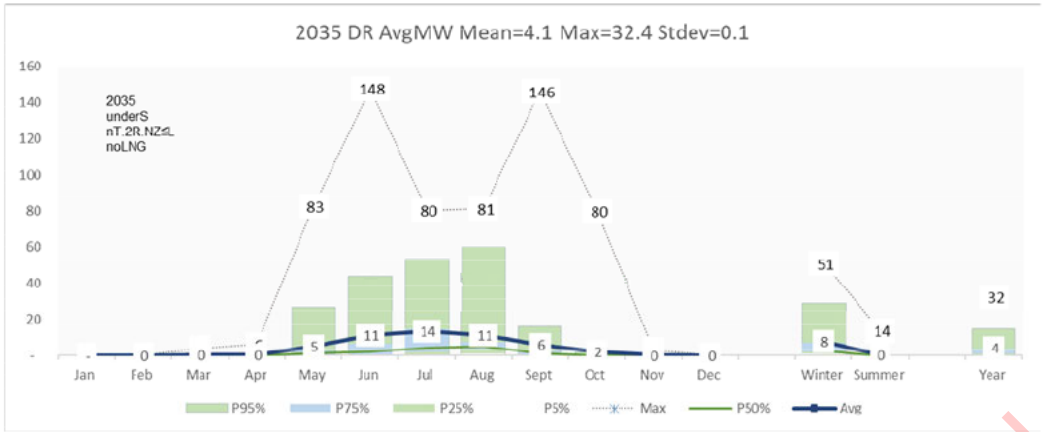


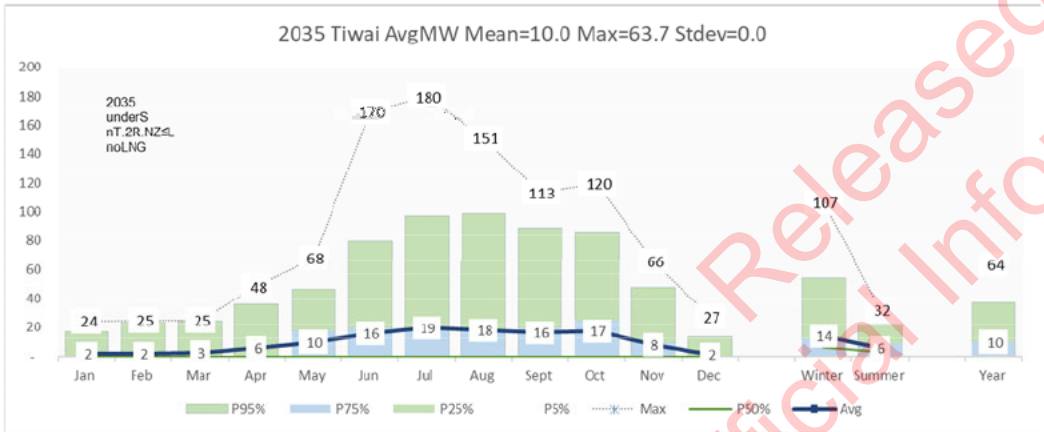


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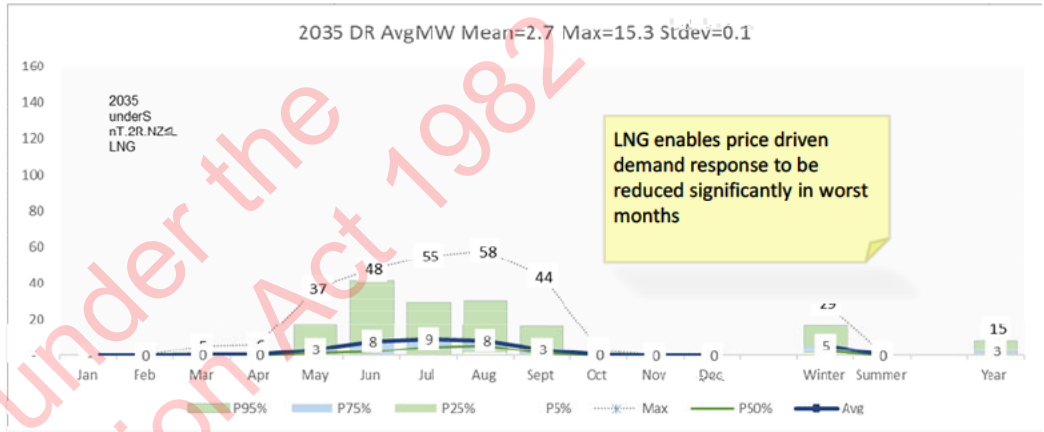
Shortage for 2035 stressed scenario (under supply, no Tariki, only 2 Rankines), split gas market: with and without LNG

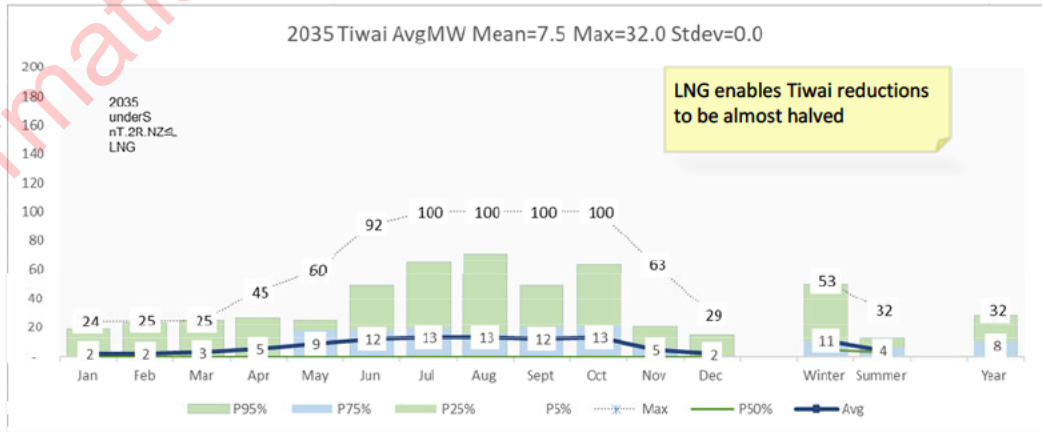
No LNG





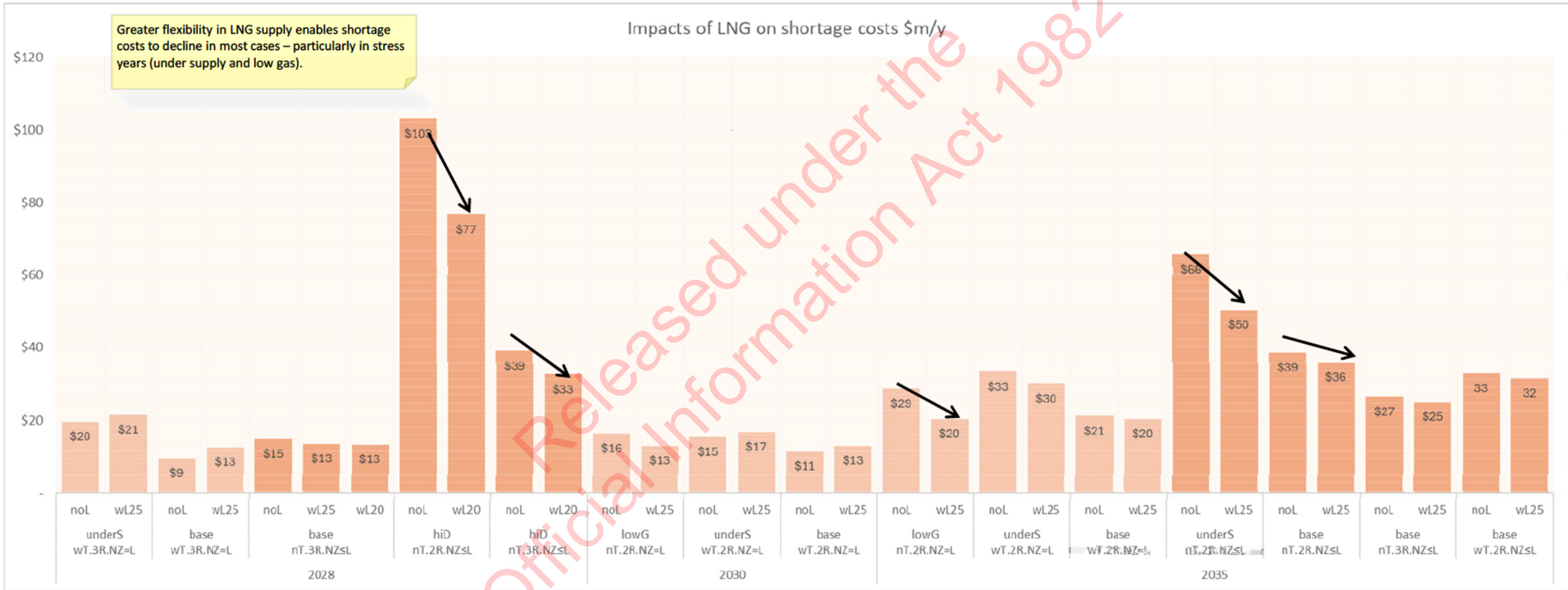
With LNG





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Impact of LNG on average Shortage costs (Tiwai & other DR)



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Impact of LNG on Fuel use mix in PJ/y (mean)

Total fuel mix varies only slightly due to different heat rates on different fuels, and small changes in demand response

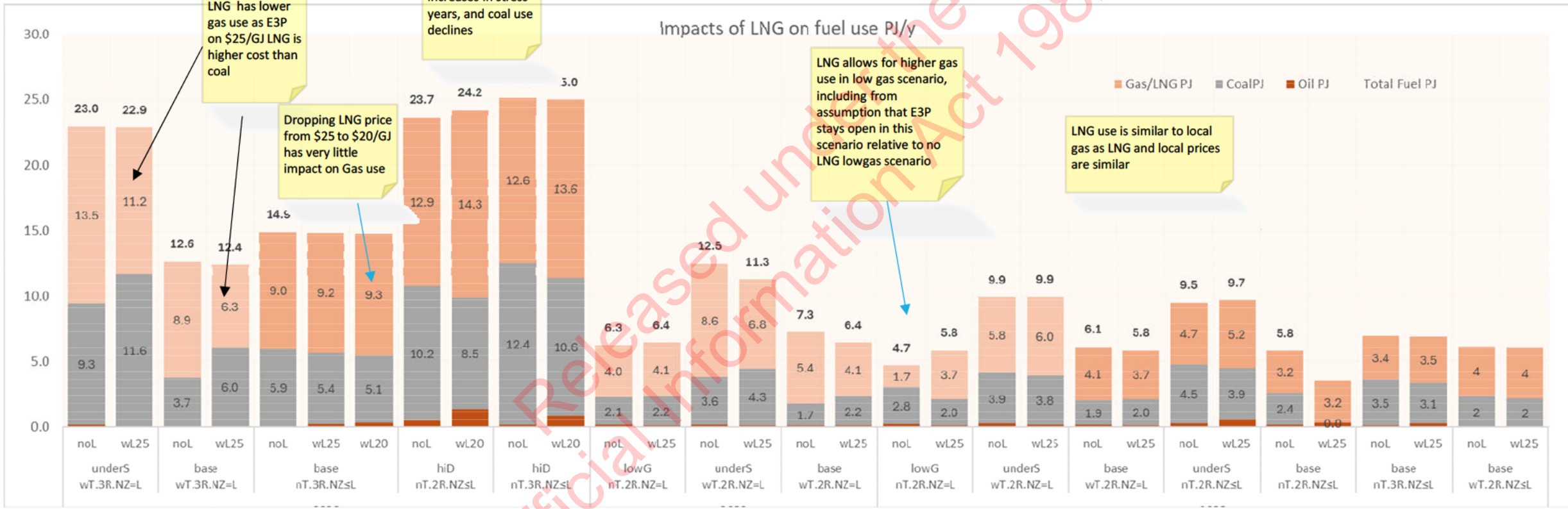
LNG has lower gas use as E3P on $25/GJ LNG is higher cost than coal

Gas/LNG use increases in stress years, and coal use declines

Dropping LNG price from $25 to $20/GJ has very little impact on Gas use

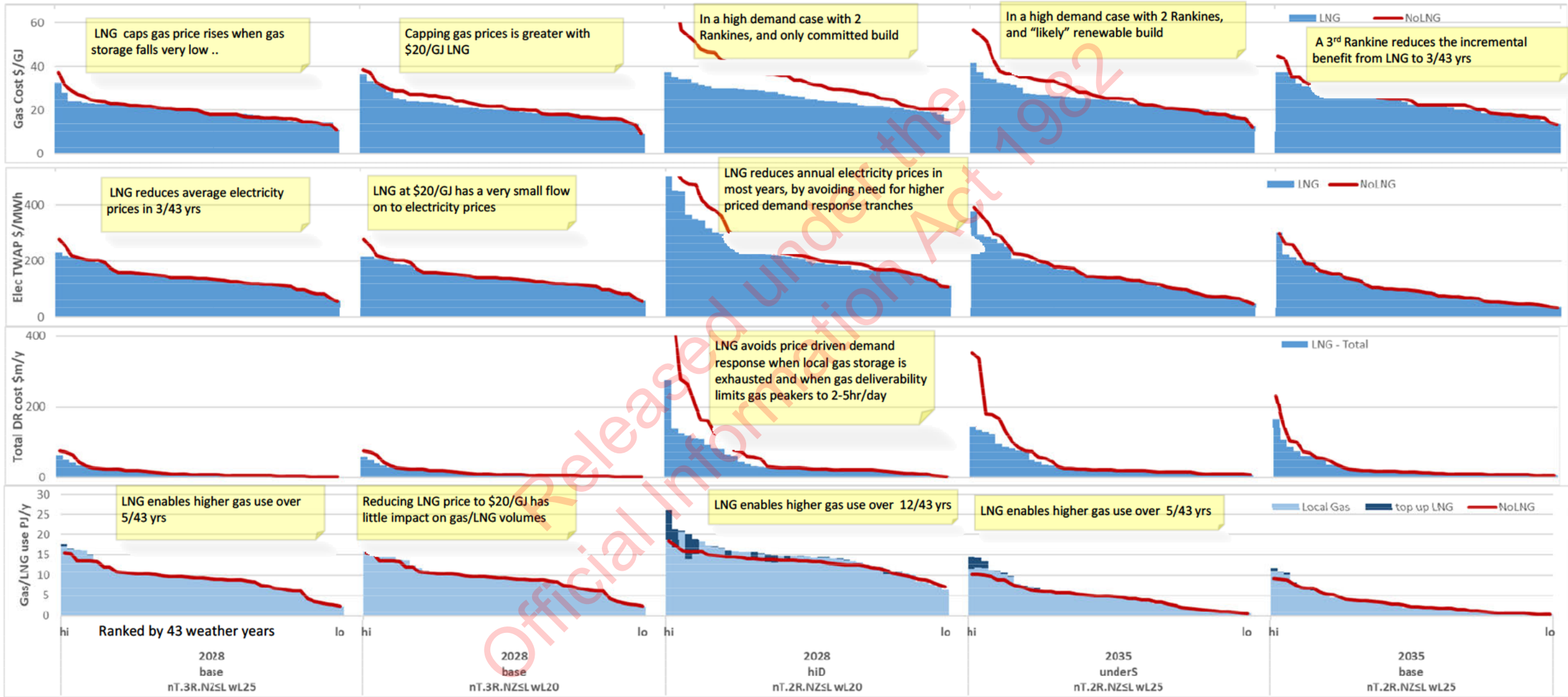
LNG allows for higher gas use in low gas scenario, including from assumption that E3P stays open in this scenario relative to no LNG lowgas scenario

LNG use is similar to local gas as LNG and local prices are similar



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Split market analysis shows incremental impact of LNG above local gas supply

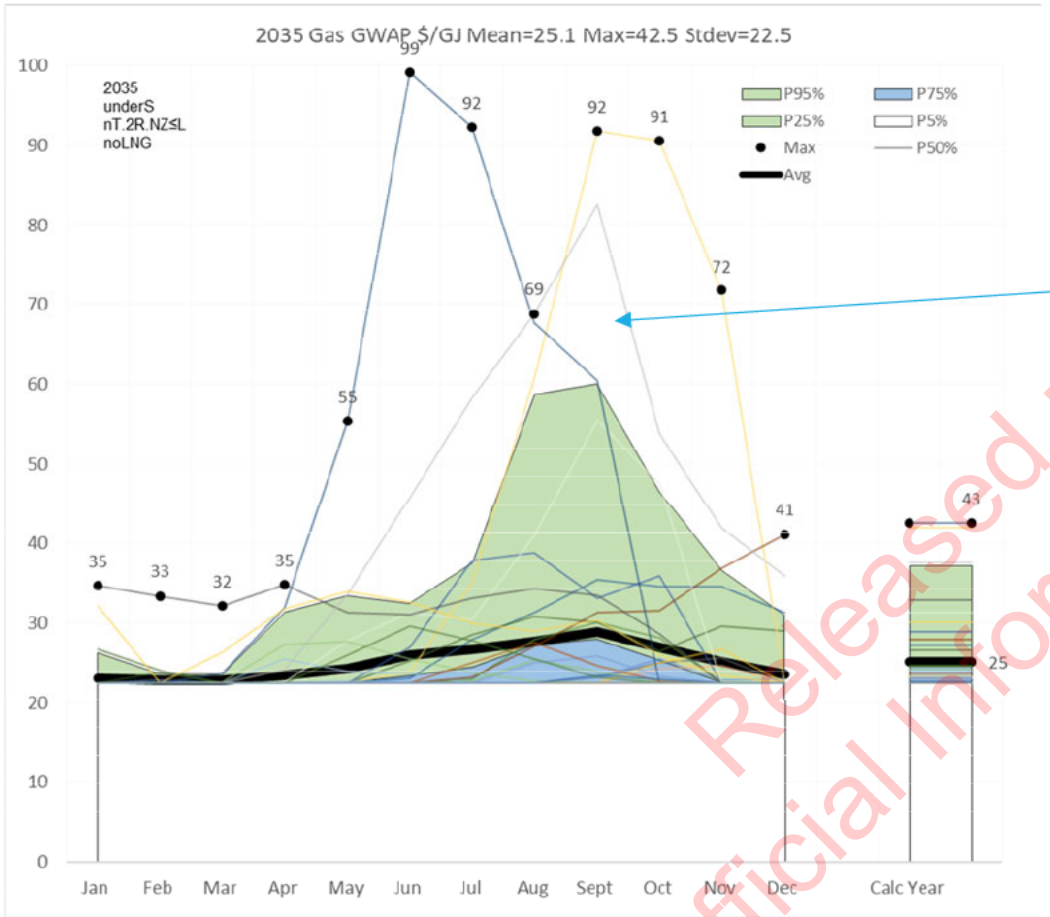


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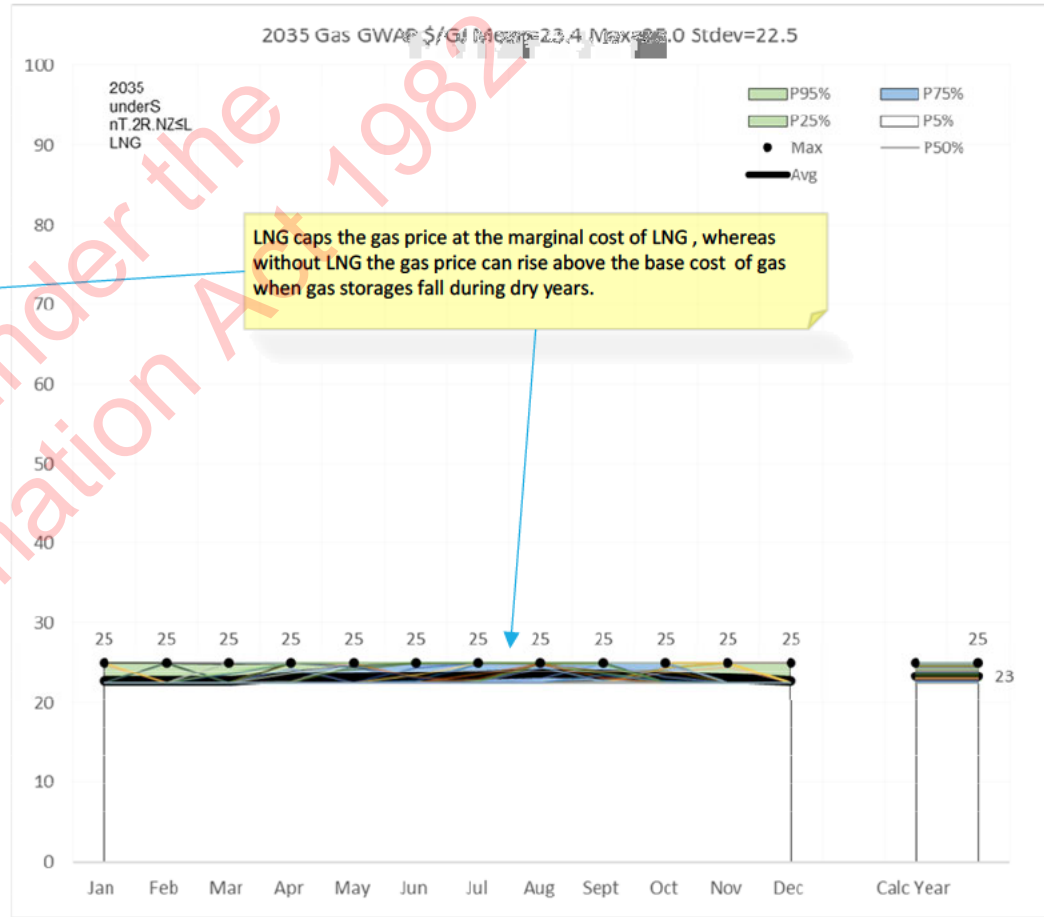
Note - The insurance benefit of having LNG flows through to water values and to gas pricing, which impacts the timing of Tiwai demand response and the mix of thermal fuels.
- The top-up LNG is a strictly marginal requirement for LNG – on the assumption that all local resources are used first, this is generally less than the incremental demand for LNG (equal to the with and without difference in gas/lng use)
- Actual LNG use, if available, will depend on the pricing of local gas compared to imported LNG. It could be up to the total gas/LNG demand, if local gas is priced above LNG, or down to the strictly marginal top-up if local gas is always priced below LNG.

Gas prices for 2035 under supply, no Tariki, only 2 Rankines, split gas market: with and without LNG

No LNG



With LNG

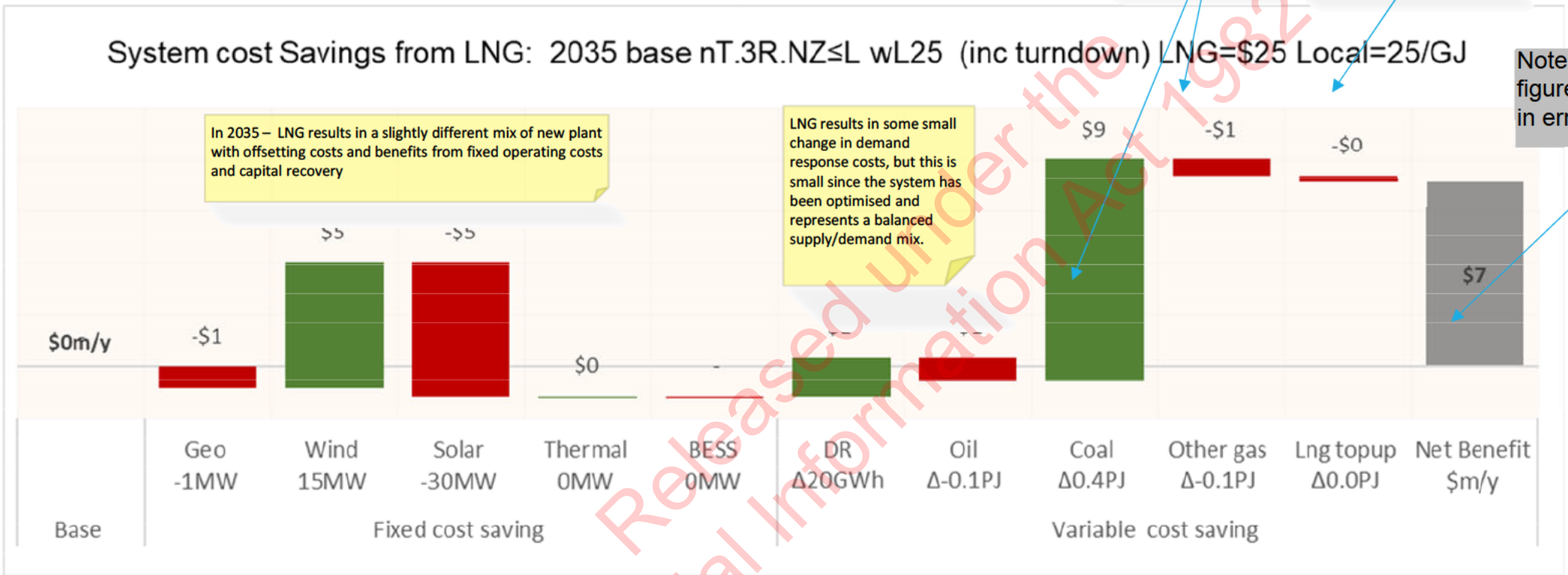


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- LNG reduces the extent of very high gas prices during dry inflow sequences.

Illustrative expected net benefits (averaged without a risk premium)

Note of clarification, the title above is in error Should read: System cost Savings from LNG" as appears in graph below



In 2035 – LNG results in a slightly different mix of new plant with offsetting costs and benefits from fixed operating costs and capital recovery

LNG results in some small change in demand response costs, but this is small since the system has been optimised and represents a balanced supply/demand mix.

The main impact of LNG is to reduce the local coal costs

The savings in coal are offset by the marginal cost of LNG use.

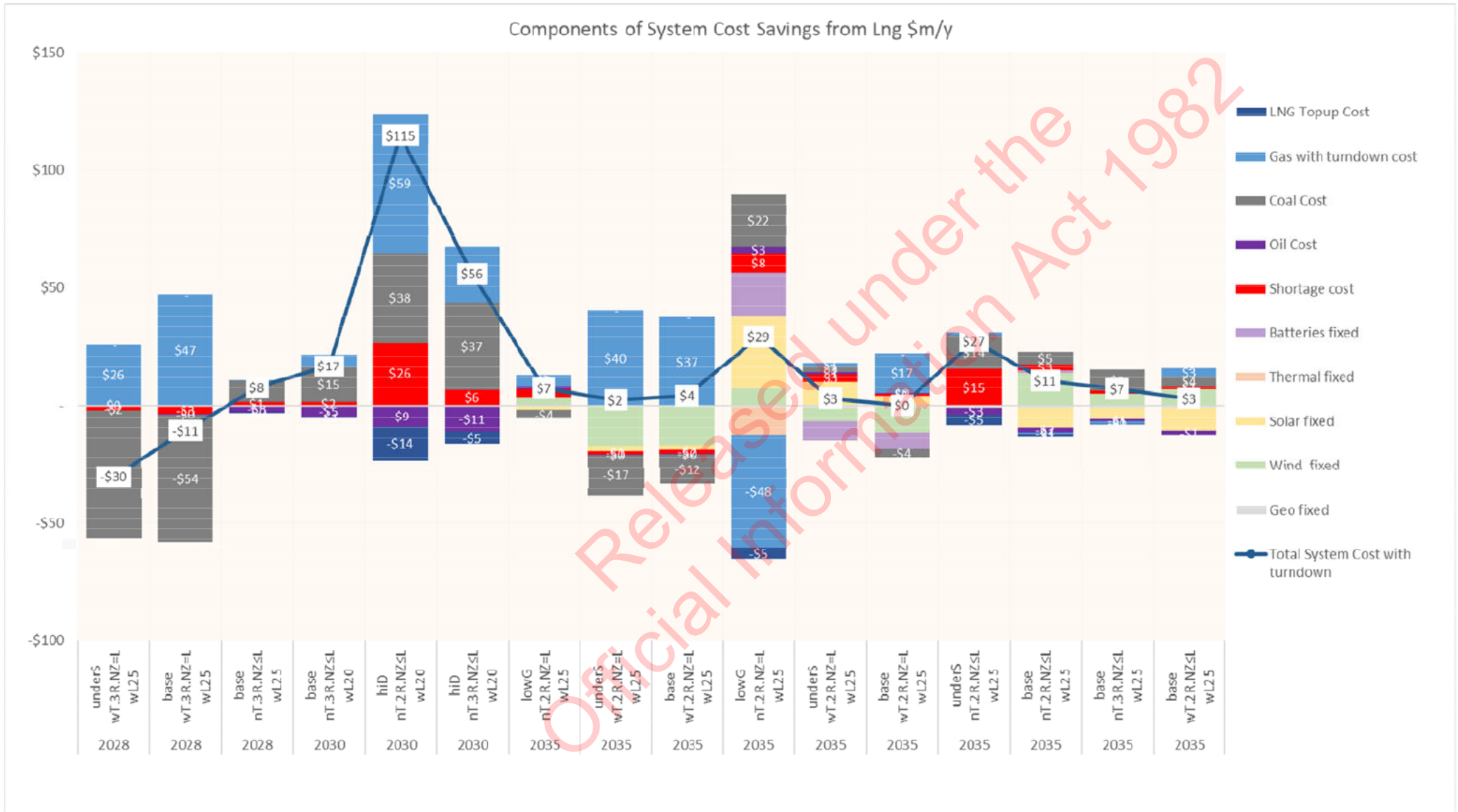
Note of clarification $19m figure on comment below is in error. Correct figure is $7m

Net benefit is $19m/y before accounting for LNG infrastructure costs

The breakdown of total gas variable costs between LNG and other gas is based on the LNG cost of topup gas in the LNG case, with other gas costs being a residual.

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Average system cost savings (assuming LNG commodity is $20/GJ or $25/GJ)



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The chart shows the components of the average system cost savings for all of the runs.

The is a range of -430m/y to 115m/y. This is based on an average over 43 weather years without risk aversion.

The total system cost savings are greatest in the scenarios with high under supply relative to demand and with no Tariki and lower LNG prices.

In these cases the range is +$115m/y to $7m/y.

The savings are much lower when the system is in relative supply and demand balance, and/or where there is additional gas storage from Tariki.