

ICCC MODELLING: DRY YEAR STORAGE OPTIONS ANALYSIS

Final Report

April 2019

Report to the Interim Climate Change Committee

John Culy Consulting

ICCC Modelling: Comparative analysis of dry year backup options

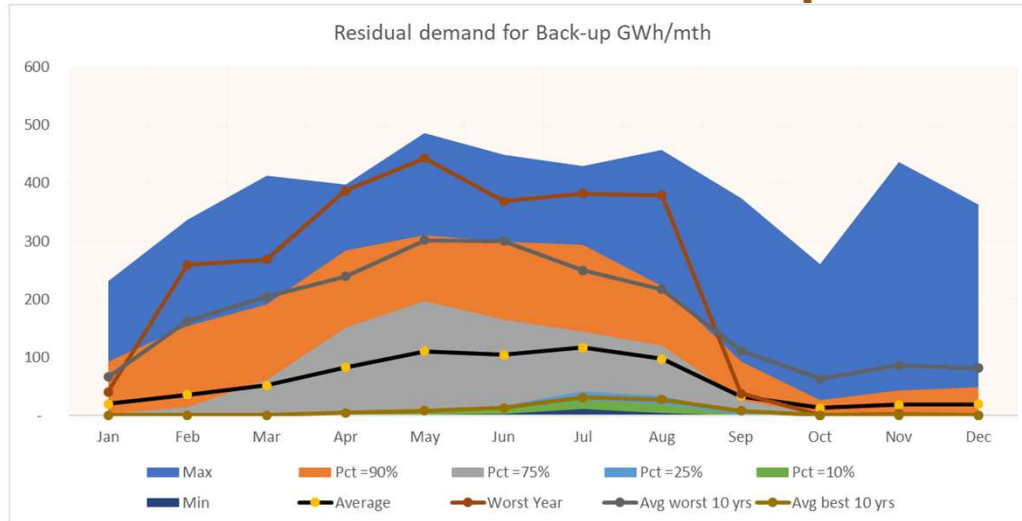
Final Slides : John Culy

25 Apr 2019

Introduction

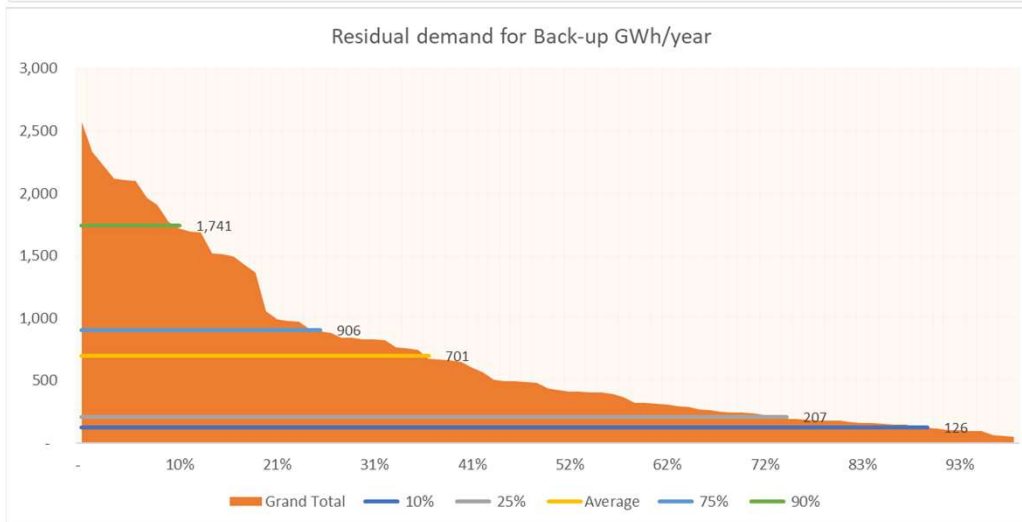
- Currently natural gas and oil flexible peaking generation provides an effective, low cost, back-up to cover wind and solar intermittency and dry years with low hydro generation.
 - The modelling shows that once base load thermal is retired and replaced with geothermal, wind/solar and batteries around 98% renewable (on average) can be achieved by 2035 at relatively low cost.
 - The last 2% of generation in 2035 is around 0.7TWh/yr on average but varies between 0.1 and 2.6TWh/yr depending on the weather (mainly hydro inflows and wind). This requires flexible fuel supply of up to 25PJ with a mean of around 7PJ/yr. The peaker capacity is 820MW and the average capacity factor is around 10%.
 - It is assumed that natural gas supply flexibility is met from 17PJ of gas storage at Ahuroa plus an additional 8PJ/yr flex in gas supply
 - It is assumed there is a capital cost of \$200m for upgrades to Ahuroa (to increase withdrawal capacity to 150TJ/d) and working capital costs of \$10m/y and fixed option fees of \$22m/yr to secure access to 8PJ/y of flexible gas priced at a variable cost of \$9.6/GJ. This implies an average gas cost of around \$17/GJ including flex and storage.
- These slides compare a number of options for eliminating this residual fossil fuel required for long term back-up.
 - The options explicitly compared in this report include:
 1. **Overbuilding renewables** - assumes additional wind/solar and batteries to replace the gas peakers
 - this is based on the Energy Link modelling runs described in “*ICCC modelling: Estimated system incremental and marginal costs in 2035*”, John Culy, 25 April 2019
 2. **Hydrogen and Ammonia** - assumes new hydrogen production and conversion of Ahuroa to hydrogen storage and additional ammonia storage to meet demand.
 - this is based on a standalone modelling described in a set of slides “*ICCC Modelling : Hydrogen Storage Options Analysis*”, John Culy, 25 April 2019
 3. **Pumped hydropower** - assumes a 1000MW pumped storage facility with 5TWh of storage in the South Island above the Clutha scheme.
 - this is based on a standalone modelling described in a set of slides “*ICCC Modelling: Pumped hydro storage - Lake Onslow option analysis*”, John Culy, 25 April 2019
 4. **Biomass** - assumes new wood pellet fired peaking plant with associated covered wood pellet storage.
 - This is based on assumptions from *Concept (2019)* and additional assumptions for pellet storage costs
 5. **Indicative large-scale demand interruption** -
 - This is an assessment of a hypothetical very large customer who is prepared to be completely shut down for up to 6-8 months with a frequency of around (1 in 5 year) in return for a fee.
 6. **Long-term battery storage**
 - This is based on a very large battery with a capacity of around 2,700 GWh operated in “peaker” mode.

Residual Demand for Gas peakers



The monthly and annual distributions for the residual demand for gas/oil peaker back-up is illustrated in the charts.

This shows that the demand is most often in winter, but there are occasions (when hydro lakes are low at the start of a year as a result of a previous dry year) and current inflows are low as well, when the demand for gas peakers is sustained for periods of up to 6 months.



Summary of Back-up Cost estimates

Counterfactual: Gas Peaker Back-up

- This is the demand for gas/oil peakers in the 98.6% renewable Middle of Road electricity future.
- This has a average demand of 0.7TWh from gas/oil peakers or 7PJ/yr (0.33mt emissions).
- Annual cost = \$118m/yr consisting of:
 - \$66m/yr = variable fuel cost at an average \$9.6/GJ
 - \$24m/yr = fixed option fees for right to take up to 8PJ/yr at \$10/GJ
 - \$10m/yr = fixed working capital costs for Ahuroa gas storage
 - \$18m/yr = fixed cost of upgrading Ahuroa to 150TJ/day extraction rate (\$0.2b capex)
- Average cost = \$18/GJ for flexible gas at 10% capacity factor from storage and supply flex.
- Notes:
 - The key risk for this option is continued availability for around 7PJ of gas supply and storage or supply flex up to 25PJ.
 - Extra costs have been allowed for to enable this flexibility in the future given that current sources of gas supply flexibility for electricity use are likely to reduce if Methanol production shuts down and off-shore gas supply flexibility is phased out.
 - Any increase in the cost of providing gas flexibility will reduce the estimated abatement costs for the other back-up options.

1: Overbuilding Renewables

- This replaces 0.7TWh of gas/oil peakers with 1174 MW of new renewables and 500MW (5.25 GWh) of batteries and extra demand response and shortage.
- Annual cost = \$412m/yr consisting of:
 - \$55m/yr shortage and demand response
 - \$107m/yr battery fixed cost (\$1.0b capex)
 - \$250m/yr new renewable fixed and variable cost (\$2.7b capex)
- Total capex = \$3.7b
- Emission saving = 0.232
 - 0.334mt (fossil fuels) - 0.102mt (extra emissions from extra geothermal)
- The extra costs of over building with renewables relative to gas peakers is \$294m/yr or \$1,270/t emission abatement cost.
- Notes:
 - This is slightly lower than the estimates given in the system costs report as the counterfactual now includes a more explicit modelling of the fixed and variable costs of gas supply.
 - The abatement cost with additional investment in wind to reduce storage and demand response costs back to normal levels is similar considering that the additional capital costs are mostly offset by reductions in shortage and demand costs.

Dry year back-up Options 2 and 3

2: Hydrogen storage at Ahuroa and Ammonia

- This involves conversion of Ahuroa to hydrogen storage (5PJ), a 1.6GW Hydrogen plant, a 12PJ/yr Ammonia plant, 20PJ of ammonia storage and 0.82GW of hydrogen peakers.
 - This generates 0.7TWh, but has an electricity demand of 5.1TWh since the combined efficiency is 13.6%.
- The annual cost of this is \$625m/yr, consisting of
 - \$171m/y electricity purchase costs 5.1TWh at \$33.5/MWh
 - \$14m/yr variable operating costs for H2 peakers
 - \$31m/y variable operating and network cost for electrolyser
 - \$28m/yr working capital for H2 and ammonia in storage
 - \$381m/yr capital recovery on \$3.7b capex and fixed operating cost
 - 1.6GW Electrolyser (capex \$1.1b), 12PJ/yr ammonia plant (capex \$0.6b), 20PJ ammonia tanks (capex \$1.0b), 0.82GW new H2 peakers (capex \$0.8b), 5PJ Ahuroa conversion to hydrogen (capex \$0.2b)
- Total capex \$3.7b
- Emission saving = 0.334 mt
- The extra costs of hydrogen/ammonia option is \$507/yr or \$1,520/t implied emission abatement cost.
- Notes
 - This is slightly higher than the \$1440/t in the hydrogen storage option report since the project is scaled up to fully replace the gas peakers. The risks and uncertainties are summarised in that report.

3: Pumped hydro storage

- This involves the creation of 5TWh storage reservoir in the Onslow basin by building a dam and a 15-24km tunnel down to an under ground 1GW pumping/generation station which discharges into the Clutha river. This would operate as a generator when required and a pump during wet periods when power was not required.
 - By virtue of the large storage and greater capacity, this option would be able to provide more than the dry year backup required to replace the gas peakers. Separate modelling indicates that it can provide up to 5TWh of dry year backup and save around 1.5TWh of backup thermal plant, and 0.61mt of emissions. The full capital cost is estimated to be \$3.2b.
 - For the purpose of this comparison the value of generation to replace the same 0.7TWh of gas peakers is counted and the full capital cost recovery is offset by the additional benefits from the full scheme.
- The net annual cost of this option is \$268m consisting of:
 - \$290m/yr recovery for the full capital cost and fixed operating cost
 - \$29m/yr electricity purchase cost for pumping to meet the 0.7TWh/yr required to replace the counterfactual dry year backup demand.
 - -\$50m/y as a credit for the benefits from the extra gross margin from the additional 0.8TWh/yr of dry-year backup available from the full project.
- This extra net annual cost is \$150m/yr and the overall carbon savings are 0.334 mt + 0.276mt = 0.61mt , so the carbon abatement cost is \$250/t.
- Notes:
 - This is the same as that derived in the Pumped Storage report. The risks associated with this option are summarised in that report.

Dry year back-up Options 4 and 5

4: Biomass fired back-up plant

- This involves the construction of around 16 new 50MW biomass backup plant located near wood supply sources with 20PJ of covered wood pellet storage facilities (possibly silos).
 - It is assumed that biomass back-up plant have a cost of \$2,600/kW, and wood pellets cost \$20/GJ and wood pellet storage has a capital cost of \$15/GJ of storage (based on reported costs of \$10/GJ for grain silos and \$20/GJ wood pellet storage and handling facilities at ports).
- The annual costs of this option would be \$384m/yr:
 - \$129m/yr wood pellet fuel costs
 - \$30m/yr working capital for the cost of wood pellets in storage
 - \$226/yr fixed capital recovery and operating costs - from
 - Pellet storage facilities (capex \$0.4b)
 - New biomass backup plant (capex \$2.1b)
- The extra annual costs above gas peakers is \$266m/yr, and the emissions savings would be 0.334mt implying a carbon abatement cost of \$800/t.
- Notes:
 - There is little experience of biomass being used to provide long term backup with a low capacity factor operation. The costs to maintain long term storage in the form of wood pellets without deterioration or risk of fire may be greater. Also there may be competition from other uses of wood which could push up the cost of pellets.

5: Indicative large scale demand interruption

- This is theoretical option which is provided as benchmark, rather than a realistic commercial option.
 - It would require a major load (such as Tiwai) being prepared to contract to be completely shut down for up to 6-8 months with a frequency of around (1 in 5 year) in return for a fee (assumed to be \$500/MWh).
- This would not involve a significant capital expenditure but would involve substantial costs (assumed to be \$500/MWh or \$1.7b per event) when called (1 in 5 years).
- The annual costs of this option would be \$384/yr.
 - Just the expected cost of calling for and outage at \$500/MWh.
- The extra costs is \$229m/yr and the average emission saving is 0.334 mt , so the implied abatement cost is \$690/t.
- Notes:
 - This option is very unlikely to available.

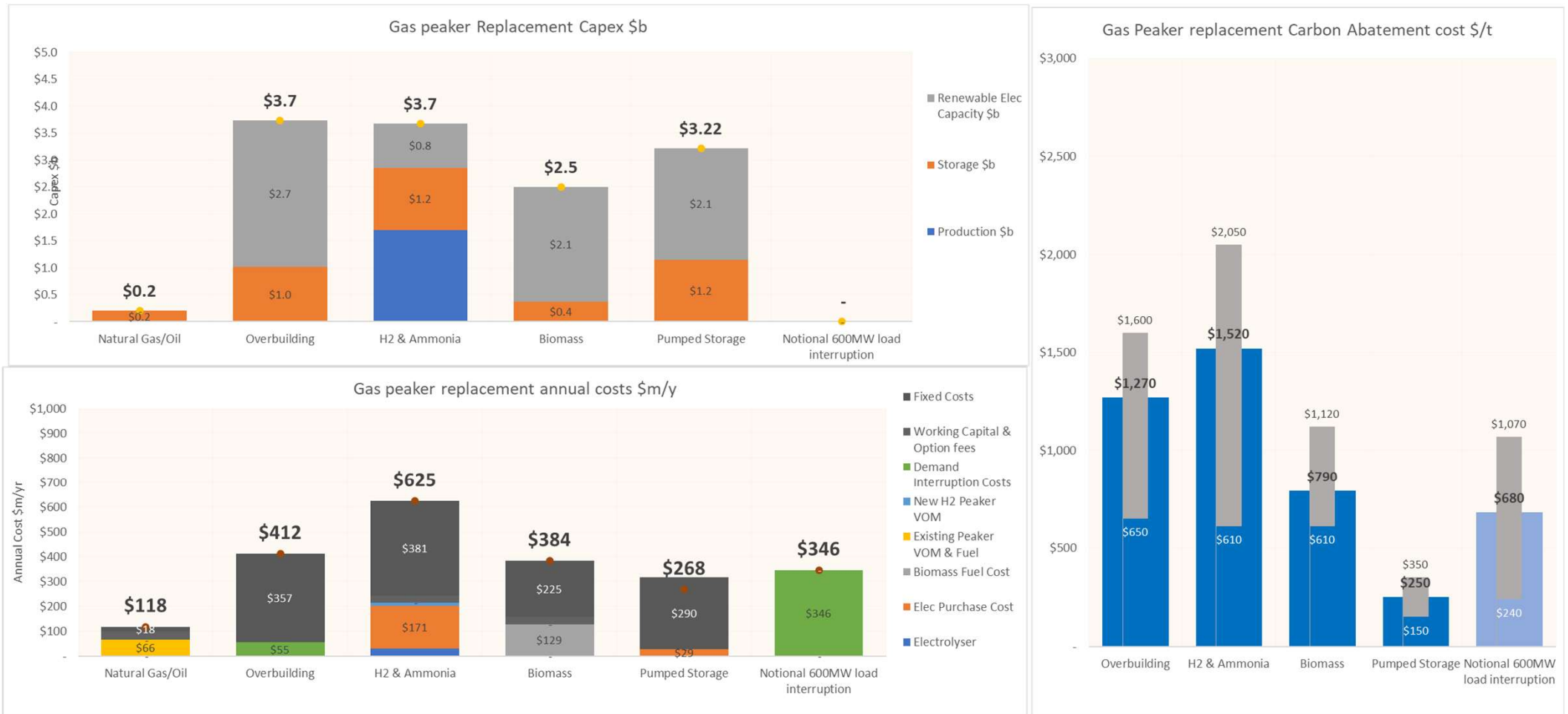
Dry year back-up Option 6

6: Indicative batteries to provide long term storage

- This involves at least 2,700 GWh of battery storage (and around 1000MW of charge/discharge capacity) which could be operated in peaker mode (i.e. charged when electricity prices were low and discharged when backup was required).
- This would incur a capital cost of \$270b (assuming battery storage capital costs fall to \$100/kWh).
- The annual costs would be at least \$28b/y. This would imply a carbon abatement cost of \$83,000/t.
- While technically feasible this option this option is clearly not an economically sensible option to provide long term dry year back-up.
 - Batteries do however have an important (economically viable) role in providing short term (within day) backup for wind and solar. Batteries operating in this mode are an important component in the renewable over build option 1.

Comparison of options to replace gas peakers

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Note that Batteries have been excluded from the chart as they are off the scale. The uncertainty ranges reflect reasonable variations in some of the key cost assumptions.

Conclusions

- All of the options considered in this report are technically feasible, but vary substantially in cost.
- The lowest cost option would be to continue to use gas/oil in existing or new peakers and to offset the 0.33mt of emissions with saving in emissions in other sectors.
- The most promising alternative option appears to be a large pumped storage facility in the South Island.
 - Additional analysis is required to assess the interactions of this option with the operation of other hydro storages and with transmission constraints including on the HVDC. Also more work is required on the cost estimates, including the costs of additional transmission.
 - It is noted that there are very significant consenting and commercial risks associated with a project of this nature and large size, but the project would enable higher electricity demand to support accelerated electrification without increasing emissions.
- Dry year back-up supply from biomass in the form of wood pellets appears to be expensive
- Although its cost might be similar, it is very unlikely that a large customer would be prepared to offer sufficient demand response to completely replace gas peakers.
 - Although, demand response can provide an important supplementary role in other options, such as overbuilding renewables.
- Dry year back up from over-building renewables or from a dedicated hydrogen / ammonia production and storage facility are very expensive, and almost certainly have a higher implied carbon abatement cost than is available from other parts of the economy.
- The very large scale battery solution is far too expensive even with significant cost reductions in batteries.
 - However short term batteries can provide an important supplementary role in some other options, such as overbuilding renewables.

Caveats and Disclaimer

Limitations and Caveats

- This report only covers a small number of illustrative options to replace gas peakers in its role of providing dry year back-up. Other options and combination of options are possible, but are beyond the scope of this report.
- There are limitations in the analysis of the hydrogen and pumped storage options which are described in the referenced reports.
- The remaining analysis is very simplified and is highly dependent on the cost assumptions made. This is illustrated by the wide uncertainty ranges shown in the chart on page 8.

Disclaimer

- The information and opinions expressed in this presentation are believed to be accurate and complete at the time of writing.
- However, John Culy does not accept any liability for errors or omissions in this presentation or for any consequences of reliance on its content, conclusions or any material, correspondence of any form or discussions arising out of or associated with its preparation.

ICCC Modelling : Hydrogen Storage Options Analysis

Final Slides : John Culy

Introduction

- These slides examine the likely costs in 2035 of meeting all or part of the dry year back-up demand for electricity using hydrogen produce market electricity (at times of low prices) and stored directly in an underground storage or indirectly in the form of ammonia.
- The modelling focuses on a specific stand-alone option using well developed technology (albeit with uncertain costs and some residual risk).
 - This involves the conversion of the Ahuroa gas storage facility to store hydrogen, the construction of an on-site hydrogen electrolysis plant and ammonia production/storage facility. For the base case it is assumed that ammonia needs to be converted back to hydrogen before burning in new 100% hydrogen compatible open cycle peakers. It is not assumed that conversion of existing gas peakers to 100% hydrogen burning is much cheaper than new hydrogen peakers.
- Four options are considered
 - These range from a 5PJ storage option from Ahuroa only and 200MW H₂ production facility, which only substitutes for a small portion of the demand for dry year back-up to a 25PJ storage option with an additional 20PJ of ammonia storage and a 1600MW H₂ production facility.
- The operation of the H₂ production and storage use is modelled using electricity prices from an EMarket simulation
 - The operational modelling is based on simulation using tuned Ahuroa and NH₃ storage operating rules and 3hr prices from the 87 weather years of the EMarket simulation with building of renewables to achieve 98.6% renewables. This has a potential.
 - This modelling determines the cost of electricity for H₂ production and the value of generation from the H₂ peakers as well as the level of H₂ and NH₃ storage over the 87 simulated weather years.
- Assumptions and sensitivities
 - The assumptions concerning costs and efficiencies in 2035 draw heavily on work carried out by Concept Consulting in 2018.
 - The very high uncertainty in the costs is addressed through extensive sensitivity analysis.
- The key results derived from the analysis are the implied carbon abatement costs for each option
 - The carbon abatement cost for the small option is \$560/t, but this only saves 0.08mt. The carbon abatement costs for the large options are > 1400/t and these save 0.27 to 0.29mt.
- Key technical risks include:
 - Ahuroa not having a significant hydrogen leakage issue and there not being significant NH₃ transport costs.

Generic and modelled options for long term hydrogen storage

Generic Options

○ Options for long term storage of Hydrogen

- **Man made salt caverns**
 - Not available in New Zealand
- **Depleted oil/gas reservoirs**
 - Possible onshore options include Ahuroa, Mkee And Kapuni
 - Ahuroa is already operating as a natural gas storage and could be converted provided hydrogen leakage is not an issue.
- **Underground Aquifers**
- **Hard rock caverns**
- **Storage of hydrogen as Ammonia**

○ General Issues

- **Hydrogen leakage** (hydrogen is a smaller molecule than methane)
- **Hydrogen Embrittlement** (exposure of steel to hydrogen makes it brittle)
- **Low energy density of hydrogen compared to methane**
- **Hydrogen contamination**
- **Technical and economic issues related to burning hydrogen or ammonia in OCGT peaking plant** (need for dilution with nitrogen or steam, flame temperature control, meeting NOx emissions limits, safety issues, managing embrittlement issues).

Modelled Options considered in this study

○ Ahuroa hydrogen storage facility

- Conversion of the existing Ahuroa natural gas storage facility (depleted oil/gas reservoir) to hydrogen storage.
- Construction of a local electrolysis plant to produce hydrogen from electricity at times of low electricity price and inject into the Ahuroa storage.
- Conversion of the existing 200MW Stratford OCGT to run on hydrogen (or replacement with a new hydrogen fired peaking plant up to 300MW) running on hydrogen.
- Investment in additional wells and compression equipment to handle hydrogen injection rates (determined by capacity of the electrolyser plant) and to handle withdrawal rates (determined by the size of the hydrogen fired peaking plant).

○ Additional ammonia storage

- Construction of additional electrolysis capacity to produce hydrogen from electricity at times of low electricity price.
- Construction of a hydrogen to ammonia conversion facility.
- Construction of ammonia storage tanks.
- Construction of additional hydrogen or ammonia fired OCGT peaking capacity.
 - If ammonia fired OCGT is not technically or economically feasible then it would be necessary to construct an ammonia to hydrogen conversion facility.

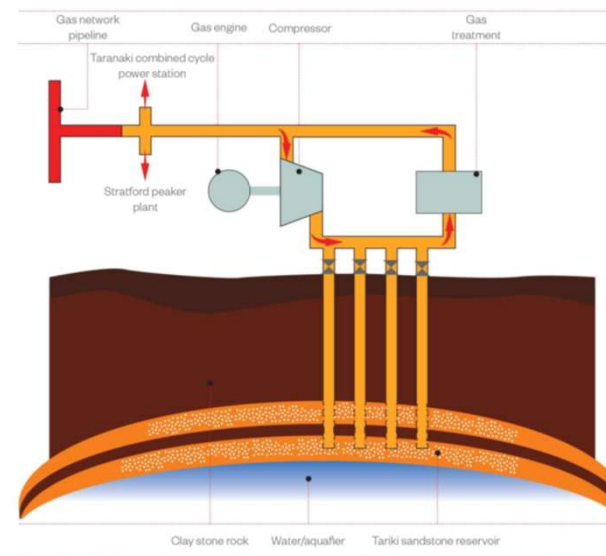
Hydrogen Storage at Ahuroa

H2 Power-Power via depleted gas reservoirs

- Ahuroa is a depleted natural gas reservoir currently being used for natural storage. It was developed by Contact Energy and sold to First gas for \$200m in 2017.
- It currently has a maximum working storage of approximately 17PJ of natural gas, with cushion gas of around 6PJ. Ahuroa has wells and compressors to inject approx. 32TJ/day and withdraw 45TJ/day of natural gas. The operating pressure has a maximum of 3,450 psi or (26MPa or 260 bar).
 - First Gas have plans to increase the injection and withdrawal capacity to 65TJ/day, and Contact indicated that the cost of an additional increments of 50TJ/day would be around \$70m. These additional increments are likely to require additional compressors, gas treatment capacity and possibly wells.
- If Ahuroa was converted to hydrogen storage it would provide around 4.9PJ¹ of hydrogen it would also require around 2.4PJ of cushion storage.
 - It is not known exactly how much injection and withdrawal capacity would be provided by the existing wells and compressors, but it is likely to be also around 1/3 of the existing TJ/day when operating on hydrogen given the lower energy density and assuming capacity relates to flow volume.
 - This implies a maximum electrolyser capacity of 12TJ/day of hydrogen production (or 200MW of electricity input assuming a 70% conversion rate).
 - The current withdrawal capacity would convert to only 15TJ/day of hydrogen (enough for around 63MW of peaker capacity).
 - An additional \$150m would be required to increase the withdrawal rate to 55TJ/day of hydrogen (225MW of peaker capacity).
 - An additional \$220m would be required to support 72TJ/day of hydrogen (300MW peaker capacity).
- Other assumptions
 - For this analysis it is assumed that hydrogen leakage from Ahuroa is not an issue. If it was an issue, it would not be feasible to cap or seal the reservoir and so viability would depend on the extent of the leakage and safety or environmental issues arising. The process of transferring Ahuroa from natural gas to H₂ is not assumed to be a significant additional cost. This would require a phased shift from 100% natural gas to 100% hydrogen over a period.

Contact Energy Cost estimates

AGS provides Contact with up to 17 PJ of gas storage capacity



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Taranaki site tour 28 July 2015

- Initial investment (excl Cap interest) \$197m
 - Assets \$111m
 - Gas rights \$35m
 - Cushion gas \$51m

- Ahuroa
 - 2 stage options to expand injection and extraction capacity at 50 TJ/day increments (\$60 - \$80m)

¹ The volumetric HHV energy density of hydrogen is 12.8MJ/m³ compared with 40.3MJ/m³ for natural gas at atmospheric pressure. This implies a 1:3 ratio at atmospheric pressure which could fall at higher pressure. I have assumed the ratio is between 1:3 and 1:4 for gas in the reservoir at a pressure up to 26MPa.

Ammonia Conversion and Storage

Technology

- Conversion of Ahuroa would only deal with a portion of the need for medium and long term storage.
- An alternative mid/long term storage option is to convert the H₂ to ammonia for storage and transport.
 - This involves the use of the Haber-Bosch process to convert hydrogen to ammonia.

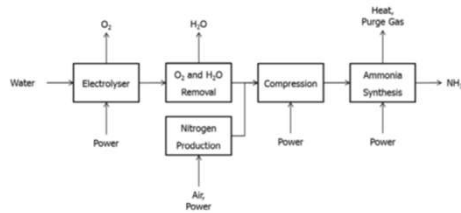


Figure 2.2: Block Diagram of Power to Ammonia

- The ammonia conversion process is relatively inflexible and so it is assumed that the conversion operates at baseload using the Ahuroa storage as a buffer to smooth fluctuations in H₂ production from the electrolysis plant.
- Bulk storage of ammonia can be:
 - at atmospheric temperature in large scale double-walled and vacuum-insulated to maintain a temperature close to -33°C, or
 - as liquid at around 7 bar pressure at 20°C in tanks similar to LNG

Cost assumptions

- Incremental Ammonia production costs = \$5.0/GJ H₂
 - Concept (2018) reports that a conventional ammonia plant (1,400 tonne/day capacity, or 35,000 GJ/day worth of H₂) with some storage capacity costs approximately NZ\$490M (based on 2012 costs from the USA) - this implies a \$38m for a each 1PJ/yr production capacity.
 - This implies that estimated that the incremental charge for an ammonia plant would be NZ\$5.0/GJ - on the basis of the HHV energy content of the hydrogen (assuming a 10% CRF and 3% of capex operating cost).
 - The estimated conversion efficiency from hydrogen to ammonia is 75%, and 80% for ammonia back to hydrogen for use in a hydrogen gas turbine peaker (overall 60% efficiency).
- Storage capital costs = NZ\$50/GJ H₂ stored
 - Bartel (2008)¹ - Estimates costs for a low-temperature ammonia storage facility, including a 25,000 t storage vessel, refrigeration system, and all ammonia handling and plant facilities, was estimated to cost US\$20.2m in 2007 dollars. This can hold the hydrogen energy equivalent of 564 GJ (HHV).
 - This is US\$36/GJ capital cost, or NZ\$62/GJ (accounting for US inflation and 0.68 exchange rate) for 0.6PJ sized storage facilities.
 - Storage efficiency is estimated to be 94% (6% losses).
 - Concept (2018) reports that 30 kt capacity refrigerated storage terminal costs in the region of NZ\$30M to build (NZ\$45/GJ H₂ capacity), and that constructing bulk pressurised ammonia storage costs around NZ\$2.00 per litre (\$117/GJ H₂ capacity).
 - Leighty (2012) reports the cost of 30kt storage as is typical in the USA corn belt is US\$15m - or NZ\$25m (NZ\$41/GJ). It is likely to cost more in NZ.
 - For this study I have assumed a capital cost of NZ\$50/GJ H₂ stored.
 - This can be compared with the minimum capital cost of over \$400/GJ for bulk liquid H₂ at -253 degrees C in insulated tanks
 - This implies a capital cost of approx. for \$250m for tanks to hold 5 PJ of Hydrogen in the form of ammonia.
 - This would require around 8-9 large scale (30,000 t) tanks typical of those used in the USA corn belt.

[1] "Implementing the Ammonia Economy", Iowa State University Jeffrey R. Bartels Michael B. Pate, PhD December 2008

[2] Concept (2018) - "H2_Report_3_Research" Concept Consulting, December 2018

[3] "Alternatives to Electricity for Transmission, Firming Storage, and Supply Integration for Diverse, Stranded, Renewable Energy Resources", William C. Leighty a, John H. Holbrook, World Hydrogen Energy Conference 2012.

Peaking Generation on Hydrogen or Ammonia

Conversion of Taranaki peaking plant to run on hydrogen

- The issues with running open cycle peakers on hydrogen include:
 - The need to dilute hydrogen with nitrogen or steam.
 - Flame stability and high combustion temperatures
 - Control of NOx emissions
 - Hydrogen embrittlement issues
- It has been demonstrated that existing gas turbines can be converted to take up to 30% hydrogen / 70% natural gas mixtures.
 - Stratford comprises 4 * 50MW , each a Pratt and Whitney TwinPack of two FT4 gas turbines.
 - While it may be theoretically possible to convert Stratford to 100% H₂ operation, it is not known if this is technically or economically feasible.
 - Assume that Stratford is almost entirely replaced with a new open cycle gas turbine designed to operate 100% on hydrogen. It is not known what the cost of a new hydrogen peaking plant (still in RD&D).
 - Assumed Costs :
 - Capex = \$1000±50%/kW for a largely new H₂ capable peaking plant on Stratford site
 - FOM = \$15±5 /kW/yr accounting for low capacity operation and safety
 - VOM = \$20±10/MWh accounting for low CF operation, H₂ handling and dilution, NOx control/scrubbing and hydrogen embrittlement issues
 - Efficiency = 36% HHV - consistent with low capacity factor operation
 - It is assumed that it is not economically feasible to convert TCC to 100% H₂ operation given its age and operational limits.
 - For this study it is assumed that Stratford is replaced or converted to H₂ firing with a capacity of 220MW at a total capital cost of \$220m.

Ammonia fired peaking plant

- Direct burning of ammonia in gas turbines is in R&D stage.
 - The 2017 ISPT report¹ concludes that ammonia-burning gas turbines are a technology for the medium-to-long term at the earliest.
- For this analysis it is assumed that ammonia is converted back to hydrogen and used in a hydrogen capable OCGT.
 - This involves around an 80% conversion efficiency.
 - It may be possible to convert other existing peakers to operate on H₂, but this is not known and would involve the transport of ammonia from Ahuroa.
 - It may also be possible to use ammonia directly in a modified reciprocating diesel engine. This is likely to be a higher capital cost than in this study, and probably would involve additional NOx control costs.
 - So for this study it is assumed a generic cost for new peakers (located near to Ahuroa without a significant ammonia transport cost) as assumed for Stratford.
- For example if we assumed 500MW of peaking capacity supplied from the ammonia storage this would require \$500m capital cost.

1) <http://www.ispt.eu/media/ISPT-P2A-Final-Report.pdf>.

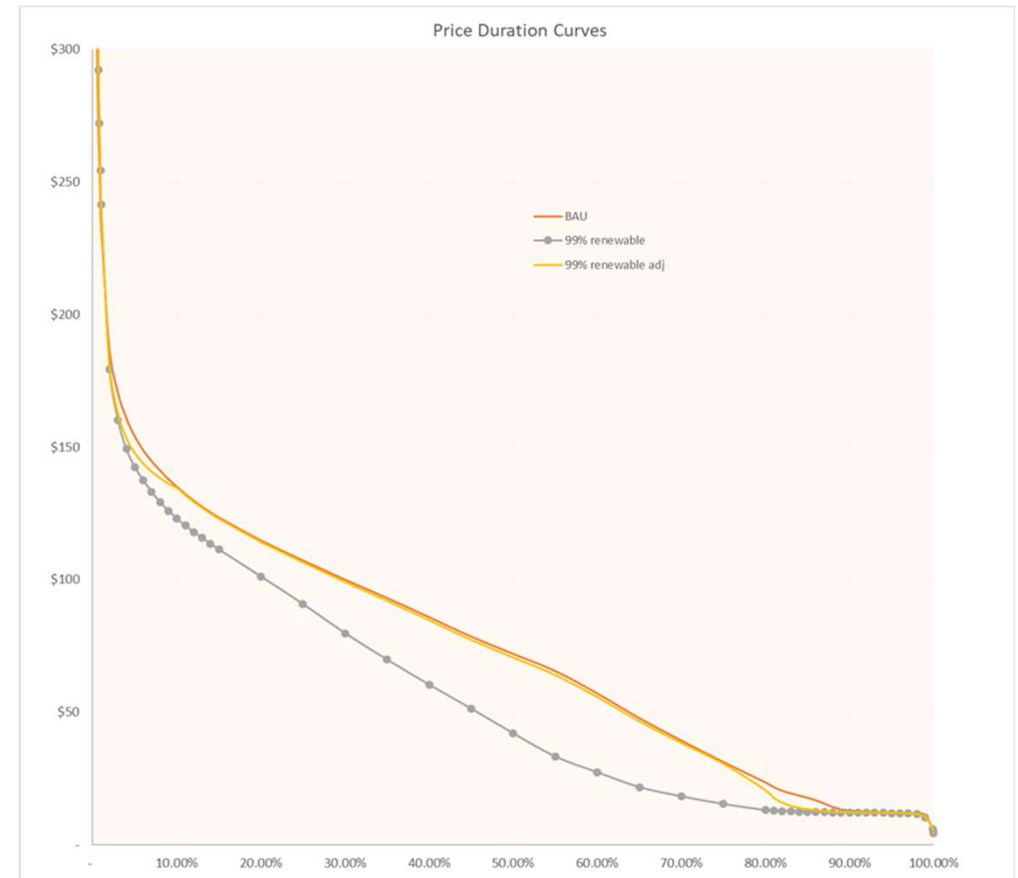
Electricity market prices

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Wholesale prices

- The operation of a combined electrolyser, H₂ storage and H₂ peaking facility is modelled using prices derived from EMarket runs.
- Used an E-market run to simulate electricity spot price outcomes.
 - The 98.6% renewable base case with closure of E3P and all cogen (except of one assumed to be converted to biomass) and some new renewables, but with around 830MW gas/oil peakers still operating to provide peak, seasonal and dry/calm year back up.
- The price duration curves for each is shown in the chart.
 - Used 2 curves for the analysis:
 1. An adjusted PDC scaled to an average HAY price of \$88/MWh. This is approx. revenue adequate and has prices falling below \$12/MWh around 15-20% of the time.
 2. The raw PDC from the model run which has an average HAY price of \$76/MWh which is not revenue adequate and has significantly lower prices at the bottom end of the price duration curve. This is an optimistic case since the cost of electricity for H₂ production is lower.
 - In each case the mean residual demand for peaker generation is approx. 0.7 TWh (1.4% of total generation). The potential emission saving is 0.33mt.

Price Duration Curves



Note: the PDC is derived from 3hrly average prices from the Emarket market simulation over 87 historical weather years , run PP_98.5_Renewable_Step7_A_MGMD_SC_1011.

Assumptions Ahuroa H₂ and NH₃ Storage - for 2035

		Low	Base	High	Notes
Electrolyser Costs					
Electrolyser Capex	\$/kW (input)	✓ \$525	\$700	✓ \$875	Concept (2018) Future cost +30% and -20% - flexible PEM
Annual cost	\$/kW/yr (input)	\$54	\$72	\$90	Capex * CRF (15 years - now - assume 20 yr life by 2035)
Electrolyser Fixed Operating Cost	\$/kW/yr (input)	\$5	\$10	\$15	Assumption ±50%
Electrolyser Variable Operating Cost	% Capex	4.0%	5.0%	6.0%	Concept (2018) ±1%
Variable operating Cost	\$/MWh (input)	\$2.4	\$4.0	\$6.0	Calculated from %capex
Variable transmission Cost	\$/MWh (input)	\$2.8	\$3.5	\$4.7	Concept (2018) 10% of Average transmission charge \$35/MWh ± 20%
Electrolyser Efficiency	%	✓ 75.0%	70%	✓ 65.0%	Concept (2018) Future efficiency ±5%
Incremental Storage Costs					
Ahuroa H2 working storage	PJ	4.3	4.9	5.7	Assumes between 1/4 and 1/3 of natural gas storage capacity
Ahuroa H2 cushion gas storage	PJ	2.1	2.4	2.8	50% of working storage
Value of cushion natural gas	\$/GJ H2 HHV	8.0	7.0	6.0	Assumption ± \$1/GJ
Ahuroa Conversion Cost 1	\$m	✓ \$124	✓ \$155	✓ \$186	Contact (2015) to enable up to 220MW peaker ±20%
Ahuroa Conversion Cost 2	\$m	✓ \$180	✓ \$225	✓ \$270	Contact (2015) to enable up to 300MW peaker
Implied Storage capital Cost	\$/GJ H2 HHV	\$42	\$46	\$48	Conversion cost / max working storage
Cushion gas Net Cost	\$m	\$11	\$17	\$26	Replace 6PJ of cushion natural gas @\$7/GJ with H2 @\$21/GJ
Avg Storage Cost (2TJ)	\$m	\$34	\$42	\$50	Cost at \$21/GJ hydrogen production cost ±5%
H2 Compressor Efficiency	%	✓ 95.0%	90%	✓ 85.0%	Concept (2018) ±5%
H2 Peaker Cost					
Stratford Peaker Conversion	\$/kW	\$500	✓ \$1,000	✓ \$1,500	Assumption: replacement of Stratford with new H2 capable gas turbine ±50%
Annual cost	\$/kW/yr	\$52	\$103	\$155	Capex * CRF
Peaker Efficiency on H2	%	✓ 38%	✓ 36%	✓ 34%	Assumption: Low capacity factor operation on H2
FOM (on H2)	\$/kW/yr	\$10	\$15	\$20	Assumption ±5kW/yr
VOM (on H2)	\$/MWh	\$10	\$20	\$30	High variable cost, for low capacity factor operation, NOx scrubbing, more inspections etc ±50%
Electricity Market Prices					
Scenario		BAU	98% renew	98% renew	From Elink model hourly model runs - 87 weather sequences
Additional Ammonia Production Costs					
NH4 Production Capital Cost	\$m	\$11	\$13	\$15	For plant with 0.5 PJ/yr H2 input (assumes 0.1 CRF and 4% operating costs)
H2 to Ammonia efficiency	pct HHV	80%	75%	70%	Concept (2018)
Incremental production cost	\$/GJ HHV H2 output	\$4.0	\$5.0	\$6.0	Concept (2018) Assumes 95% CF operation
Incremental operating costs	%	2.0%	3.0%	4.0%	Bartel (2018) % of capital cost per annum
Ammonia to H2 conversion	%	85%	80%	75%	Concept (2018)
Storage Capital Cost	\$m	✓ \$188	✓ \$250	\$313	for 5 PJ of bulk storage in insulated vessels at -33 deg C
Annual Storage Cost	\$/GJ HHV H2	\$5.0	\$5.2	\$6.5	Annualised cost of storage facilities
Ammonia storage efficiency	%	96%	94%	92%	Boil off losses
Notes:					
Capital Recovery Factor	CRF	10.3%			Capital recovery factor (20yr life and 8% nominal post tax unlevered WACC)
Concept (2018)					"Hydrogen in New Zealand Report 2 – Analysis", Concept Consulting Nov 2018
Contact (2015)					"Taranaki site tour", Investor presentation, Contact Energy July 2015
Bartels (2008)					"A feasibility study of implementing an Ammonia Economy", Jeffrey R. Bartels Michael B. Pate, December 2008

Notes: all prices are in 2018 NZ dollar terms unless otherwise indicated .

1) It is possible that additional compression on the pipeline from Ahuroa to Stratford may be required (given the lower volumetric density of hydrogen). This is not accounted for in the analysis.

Results

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Results

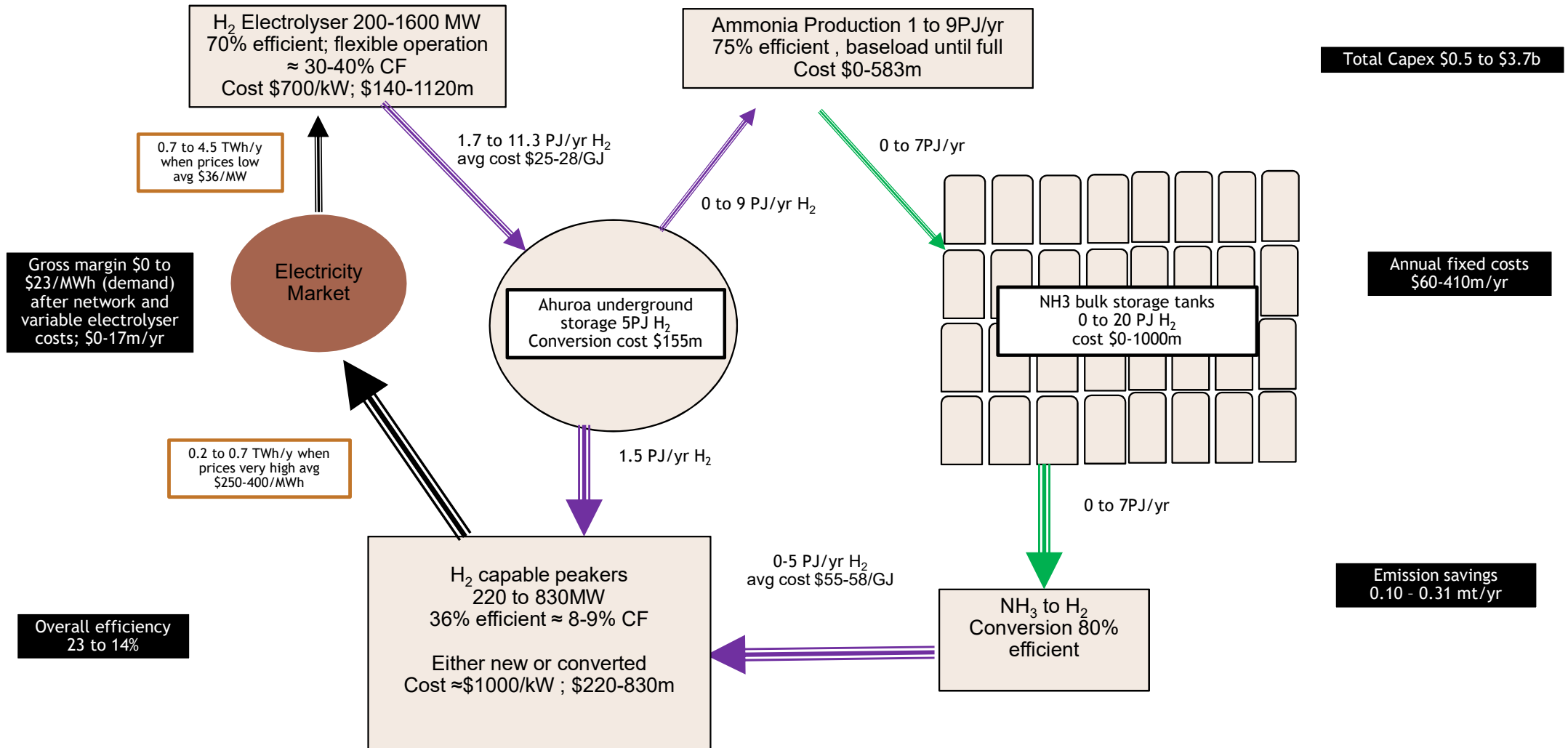
		Small (5PJ)	Medium (12PJ)	Large (20PJ)	Very Large (25PJ)
		Ahuroa Only	Ahuroa & Small NH3	Ahuroa & Medium NH4	Ahuroa & Large NH3
Capacities					
% Renewable GWh	%	98.9%	98.9%	99.4%	99.8%
% Peakers Converted to H2	%	27%	27%	63%	100%
Electrolyser Capacity	MW	200	200	800	1,400
H2 Peaker MW at Stratford	MW	220	220	220	220
NH3 Peaker MW	MW	-	-	305	610
Ammonia Conversion Capacity	TJ/yr	-	5,500	11,000	12,000
Ahuroa H2 Storage Capacity	TJ	4,857	4,857	4,857	4,857
Ammonia Storage Capacity	TJ	-	7,500	15,000	20,000
Price Set					
Time weighted Average Wholesale price	\$/MWh	98.6% renewable Adj	98.6% renewable Adj	98.6% renewable Adj	98.6% renewable Adj
		\$88	\$88	\$88	\$88
Results					
Total H2 Produced	TJ/yr	1,807	6,339	10,298	11,317
H2 Used by H2 Peaker	TJ/yr	1,619	1,252	969	969
H2 converted to NH3	TJ/yr	-	4,434	8,272	9,186
NH3 converted to H2	TJ/yr	-	3,102	5,787	6,413
H2 Average Level	TJ	2,092	2,081	2,079	2,165
NH3 Average Level	TJ	-	4,490	9,239	12,892
Elec Demand for H2 production	GWh/yr	717	2,515	4,086	4,491
Total H2/NH3 Peaker Generation	GWh/yr	162	373	560	610
H2 Peaker output Value	\$m/yr	\$48	\$116	\$180	\$193
H2 Elec Wholesale Costs	\$m/yr	\$23	\$86	\$143	\$157
Electrolyser Network & VOM Costs	\$m/yr	\$5	\$19	\$31	\$34
Peaker VOM Costs	\$m/yr	\$3	\$7	\$11	\$12
Gross Margin	\$m/yr	\$17	\$4	-\$5	-\$10
Fixed Costs Electrolyser	\$m/yr	\$16	\$66	\$115	\$131
Fixed Costs H2 Peakers	\$m/yr	\$26	\$62	\$98	\$98
Fixed Costs Ahuroa storage	\$m/yr	\$18	\$18	\$18	\$18
Fixed Cost NH3 Production	\$m/yr	-	\$28	\$55	\$60
Fixed Costs NH3 Storage	\$m/yr	-	\$39	\$77	\$103
Incremental Cost	\$m/yr	\$44	\$207	\$367	\$420
Incremental carbon abatement cost	\$/t	\$560	\$1,157	\$1,367	\$1,436
Electrolyser capacity Factor	factor	41%	36%	33%	32%
Peaker Capacity Factor	factor	8.4%	8.1%	7.7%	8.4%
Avg Electrolyser Elec Costs	\$/MWh	\$32	\$34	\$35	\$35
Avg Peaker Revenue	\$/MWh	\$299	\$311	\$322	\$316
Combined Efficiency	factor	23%	15%	14%	14%
Cost of H2 produced	\$/GJ	\$25	\$27	\$28	\$28
Cost of NH3 Produced	\$/GJ	-	\$55	\$58	\$58
Ahuroa storage capital cost	\$/GJ/yr	\$3.6	\$3.6	\$3.6	\$3.6
Ammonia storage capital cost	\$/GJ/yr	-	\$5.2	\$5.2	\$5.2
Carbon Emissions saved	mt/y	0.08	0.18	0.27	0.29
Total Capex	\$m	\$515	\$1,882	\$3,249	\$3,688
Electrolyser	\$m	\$140	\$560	\$980	\$1,120
NH3 Production	\$m	-	\$267	\$534	\$583
Ahuroa Capex	\$m	\$155	\$155	\$155	\$155
NH3 Storage	\$m	-	\$375	\$750	\$1,000
H2 Peaker Capex	\$m	\$220	\$525	\$830	\$830

Commentary

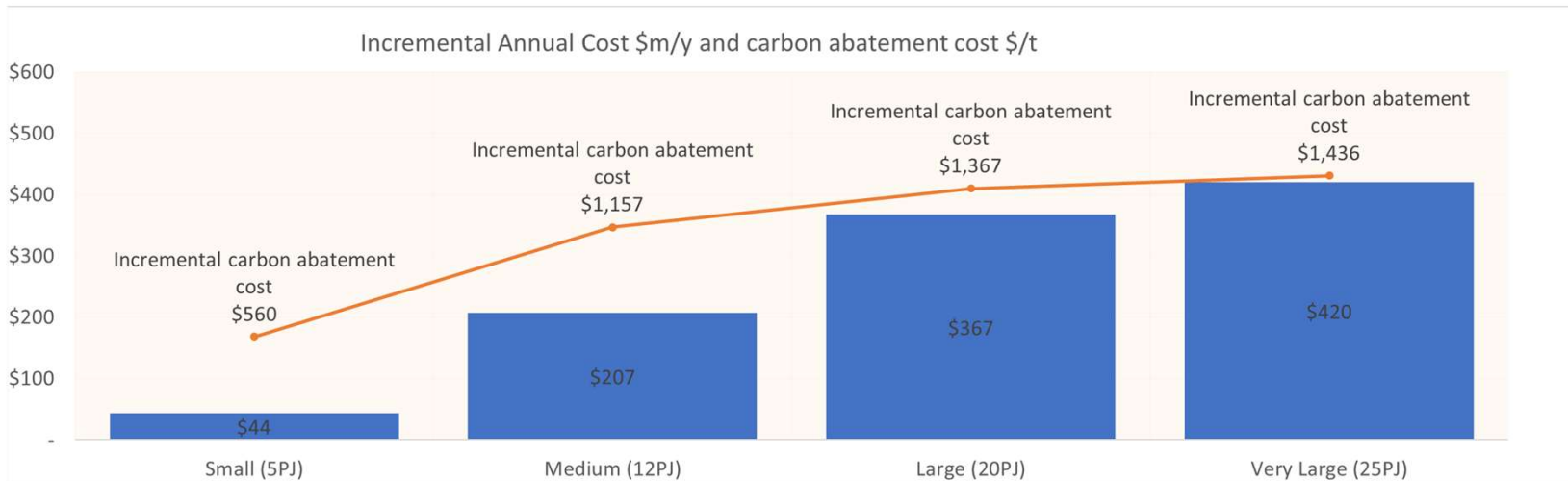
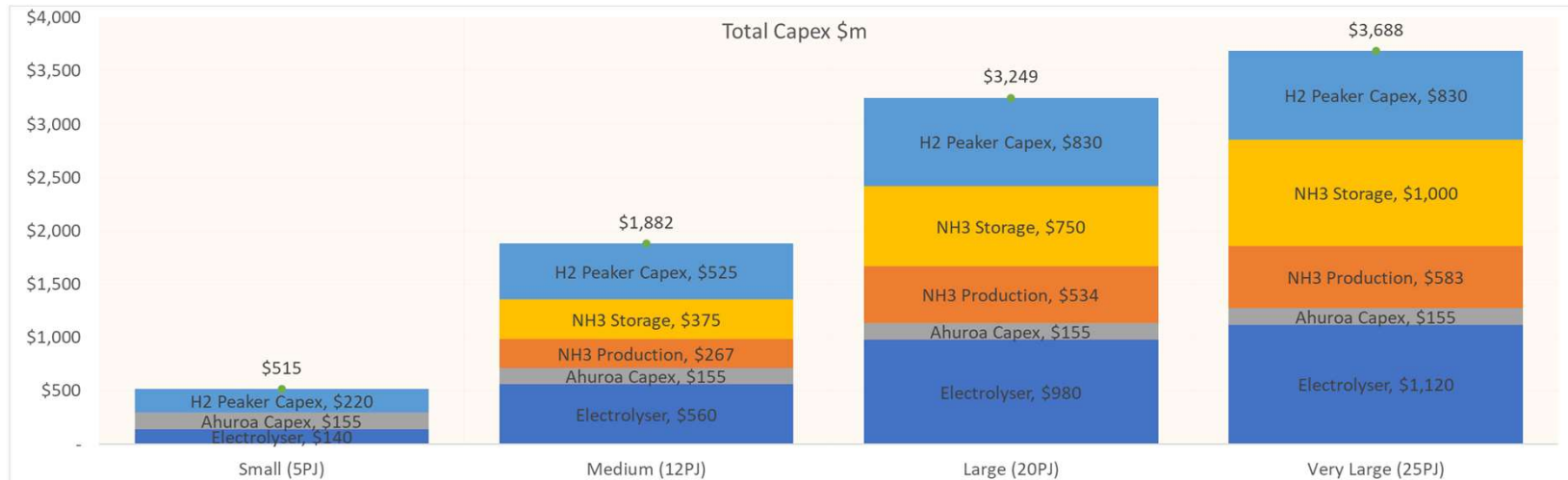
- The modelling is based on simulation using tuned Ahuroa and NH₃ storage operating rules and 3hr prices from Energy Link's market simulation with building of renewables to achieve 98.6% renewables.
 - The modelling assumes H₂ fired peakers is quite flexible and can meet within day, week, month and year demands for backup subject to modelled limits to storage of H₂ in Ahuroa and in the Ammonia tanks.
- Three configurations are considered
 - Small : 200MW H₂ plant, Ahuroa with 4.9PJ and no NH₃ tanks, 220 MW peakers
 - Medium: 800MW H₂ plant, 4.9PJ Ahuroa + 7.5PJ NH₃ storage, 525MW peakers
 - Large: 1400MW H₂ plant, 4.9PJ Ahuroa + 15PJ NH₃ storage, 830 MW peakers
 - Very Large: 1600MW H₂ plant, 4.9PJ Ahuroa + 20PJ NH₃ storage, 830 MW peakers
- In these cases the reduction in the % renewable is <0.3-1.3% as there is assumed to be overbuilding of renewables and so peaker capacity factors are low.
- The modelling indicates that the gross margin available from using low priced electricity to produce hydrogen which is used as a peaker fuel at times of very high price is generally enough to cover the variable costs and make a surplus, unless the hydrogen production is large.
 - This is achieved by buying at \$35/MWh to produce H₂ by electrolysis and earning around \$300-400/MWh in back up peakers operating at 8-10% average capacity factor.
 - This is despite an overall efficiency of only 14% to 23%.
 - The gross margin is adequate to cover the fixed electrolyser and NH₃ production costs, but does not cover the fixed costs of incremental storage facilities and new H₂ capable peakers.
- There is a net cost of replacing existing and new gas peakers with H₂ and NH₃ storage of the order of \$44 to \$441m/yr depending on the % reduction in % renewable required.
 - This implies an incremental carbon abatement cost of \$560 to \$1500/t.
 - Note the modelling of electricity prices assumes a \$50/t carbon price.

Overview - A dedicated H₂ backup facility

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Costs and incremental abatement costs



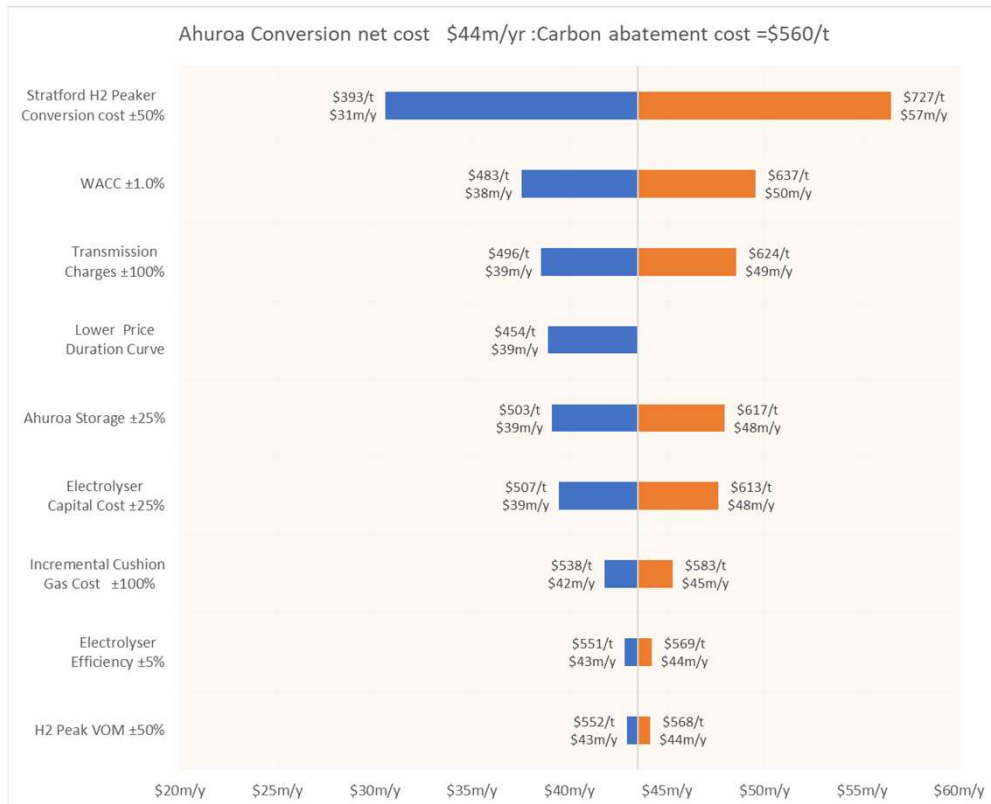
Annual incremental costs include:

- The fixed operating costs for facilities, plus
- the annualised capital costs (assuming 20yr life)
- minus the net gross margin from the electricity market (gains from selling high and buying low, net of variable operating costs).

The marginal carbon abatement cost for incremental ammonia production and storage is around \$1750/t.

Sensitivity on costs to achieve first 0.3% renewable

Sensitivity Tornado Chart -



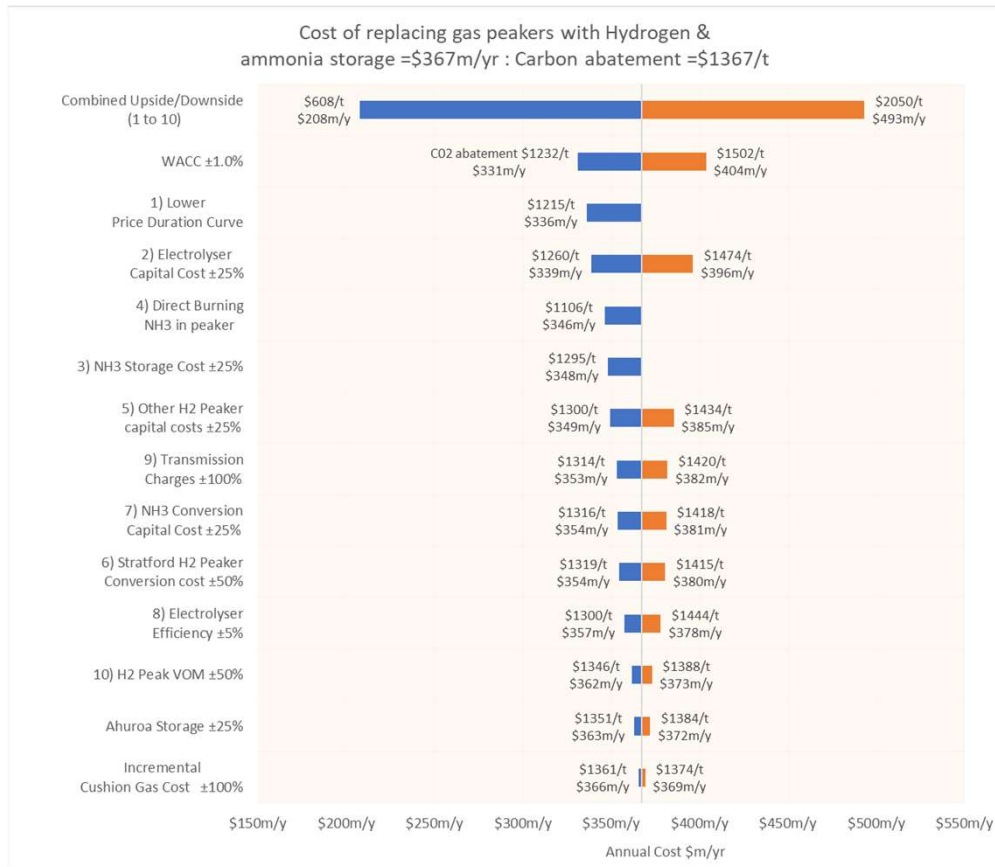
Note : each \$1m/yr corresponds to approx. \$12.9/t change in the carbon abatement cost.

Commentary

- The base case has a calculated net cost of \$44m/yr and an implied carbon abatement cost of \$560/t.
- The key factors affecting the cost are:
 - The cost of converting Stratford to H₂ operation.
 - If this could be achieved at \$500/kW then the implied incremental carbon abatement cost would be reduced to \$393/t.
 - A reduction in the cost of capital by 1% would also have a big impact.
 - As would a reduction in transmission charges and a lower price duration curve.
 - The cost of conversion of Ahuroa gas storage to H₂ would also have a big impact.
 - The base assumption is that a capital cost of \$155m would be required to enable the extraction rates to be sufficient to operate Stratford fully on Hydrogen.
 - Also the base assumption assumes that there is a low cost transition from Ahuroa operating on gas to hydrogen. This would require a careful process of operating on gradually increasing the blend from 10 to 100% hydrogen over time, and dealing with this changing blend at the power station. It may not be possible to do this, if so then Ahuroa may need to be closed while it is converted. This may involve a considerable cost.
 - Electrolyser efficiency and peaker variable operating costs (to control NO_x) have a smaller impact.

Sensitivity on costs to achieve +1.2% renewable

Sensitivity Tornado Chart



Commentary

- The base case net cost of completely replacing natural gas peakers with a combination of H₂ and Ammonia storage is \$367m/y, with an implied abatement cost of \$1367/t.
- The key factors affecting the cost are:
 - The cost of capital
 - 1% reduction gives a \$36m/yr reduction and a \$1232 abatement cost.
 - A lower price duration curve and lower electrolyser capital costs would reduce annual costs by around \$30m/yr and reduce carbon abatement costs to around 340/t
 - If it is possible to burn NH₃ in a new peaker, rather than converting NH₃ to H₂ and then burning in a peaker:
 - The cost would fall by \$21m/yr and abatement costs would fall to \$1100/t.
 - The net largest sensitivities relates to the cost of NH₃ storage.
 - A 25% reduction would save \$19m/yr.
 - The cost of converting existing peakers to run on H₂, or building new H₂ capable peakers
 - The base assumption is that this will cost \$1000/kW.
 - A 25% reduction in this cost would save \$18m/yr and reduce the carbon abatement cost to around \$1300/t.
 - Other factors have a relatively small impact on costs.
- If all the uncertainties were favourable then implied abatement costs :
 - could fall to \$608/t, but if they were unfavourable abatement costs could exceed \$2000/t.

Conclusion

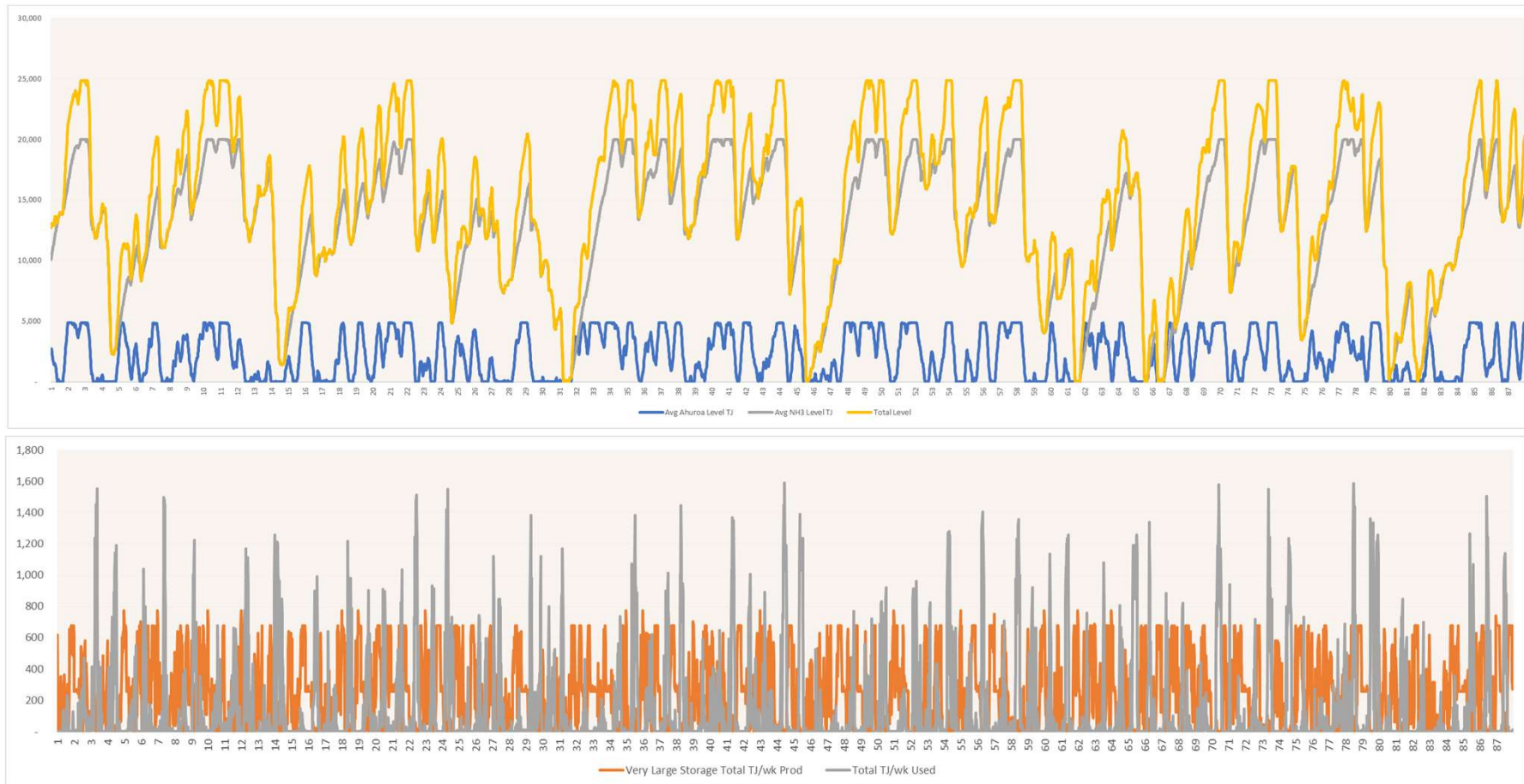
- There are significant costs in using hydrogen as a replacement for gas as a backup fuel.
- Conversion of Ahuroa gas storage to hydrogen from a electrolysis plant for use in a 220MW hydrogen fired peaker appears to be the lowest cost.
 - The technical feasibility would need to be confirmed (ie confirm leakage is not too great an issue).
- But
 - This only achieves a reduction of around 0.3% renewable, around 0.1mt of emissions and provides around 5PJ storage capacity.
 - The capital cost could be around \$515m (electrolyser, new/conversion peaker cost, Ahuroa capex to enable adequate withdrawal rates, replacement of natural gas cushion gas with hydrogen).
 - H₂ fired peakers are feasible, but are in early development and costs are highly uncertain. There are potential issues with NO_x emissions which could increase costs.
 - The conversion efficiency is around 22% (electricity out / electricity in)
 - The implied carbon abatement cost is in the order of \$560/t.
- Addition of an Ammonia conversion plant and storage would be technically feasible at a high cost:
 - This could achieve 100% renewable and save around 0.3 mt/y of emissions and provide around 25PJ of storage sufficient to cover hydro and other fluctuations.
 - The capital cost could be up to \$3.7 billion (a larger electrolyser, additional H₂ peaking plant, ammonia production facility and ammonia storage tanks).
 - The conversion efficiency is around 14% for the combined facility (lower as a result of ammonia conversion and reconversion losses).
 - The implied carbon abatement cost is of the order of \$1400/t (for the combined facility).
 - The marginal abatement cost for the additional ammonia facilities and storage is around \$1750/t.
- There might be gains from integrating this into a wider hydrogen business, however the storage and capacity requirements for H₂ use as a back up in electricity are different from other hydrogen uses and so synergies may be minimal.

Appendix

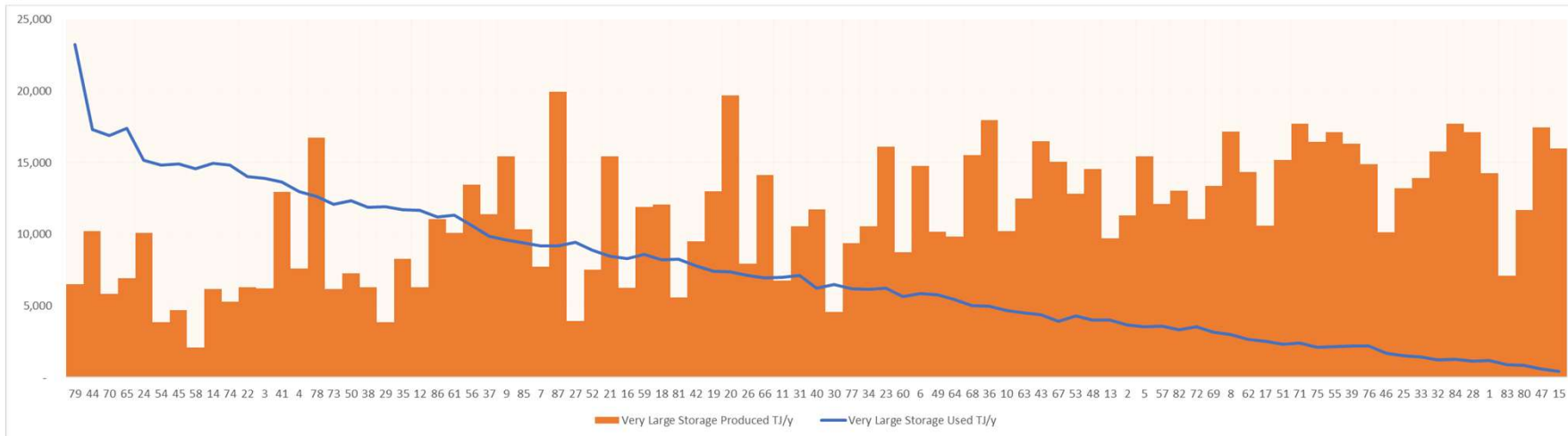
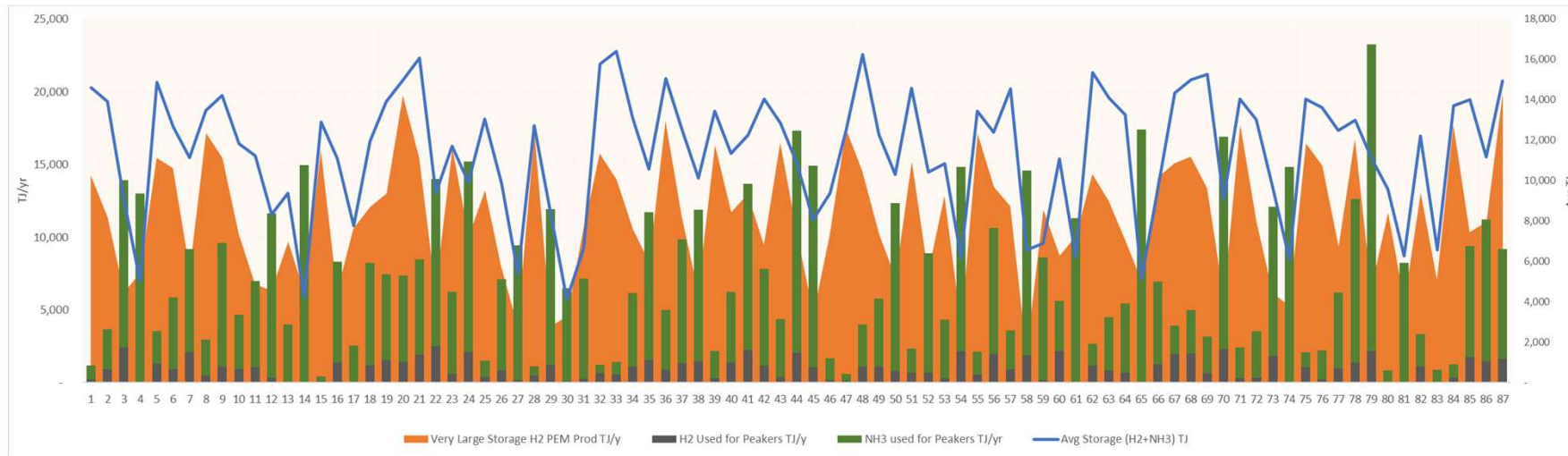
Background Charts

Max case : 25PJ storage (20PJ of NH₃ and 5PJ of H₂)

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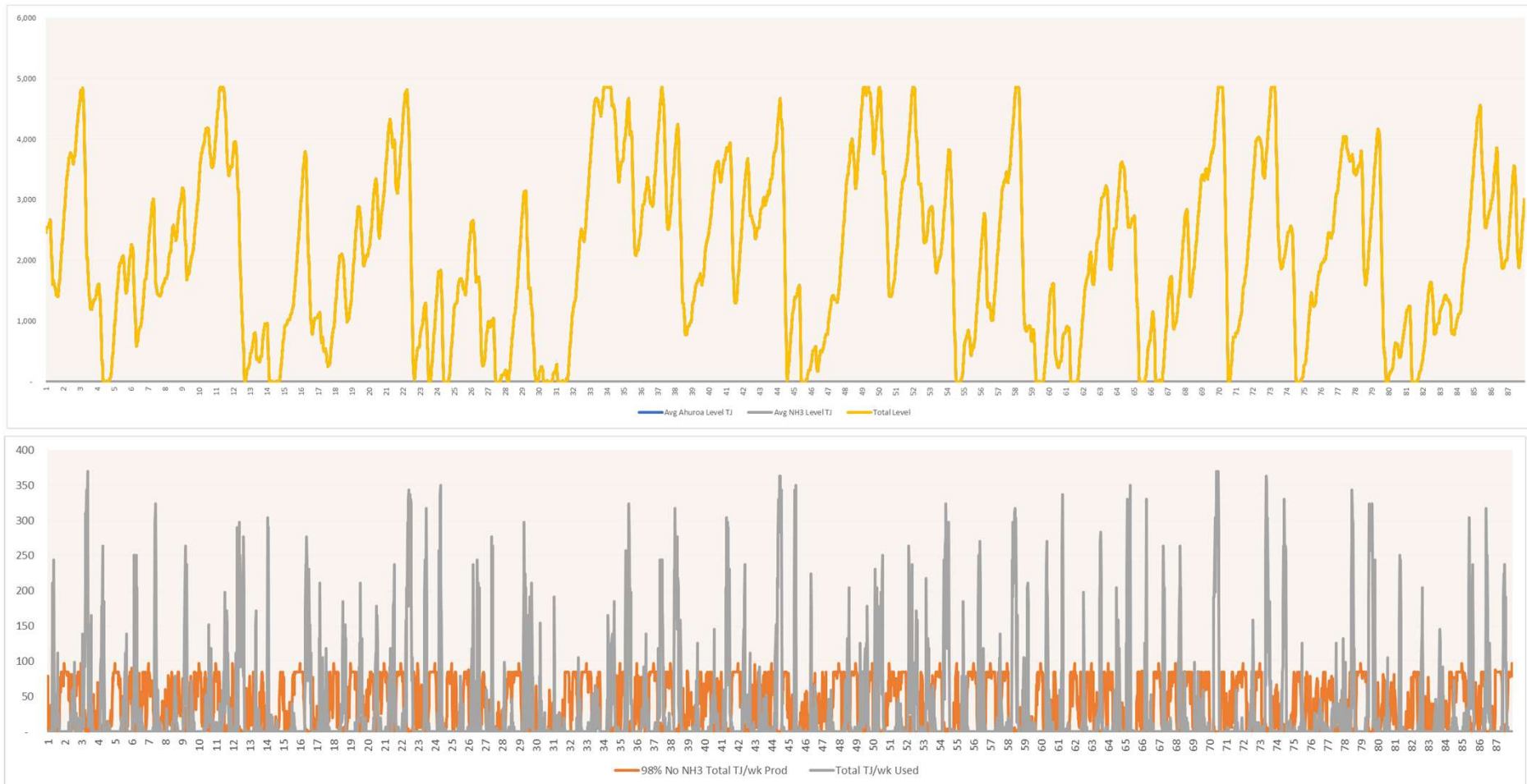


Annual Distributions: Max Case 25PJ storage

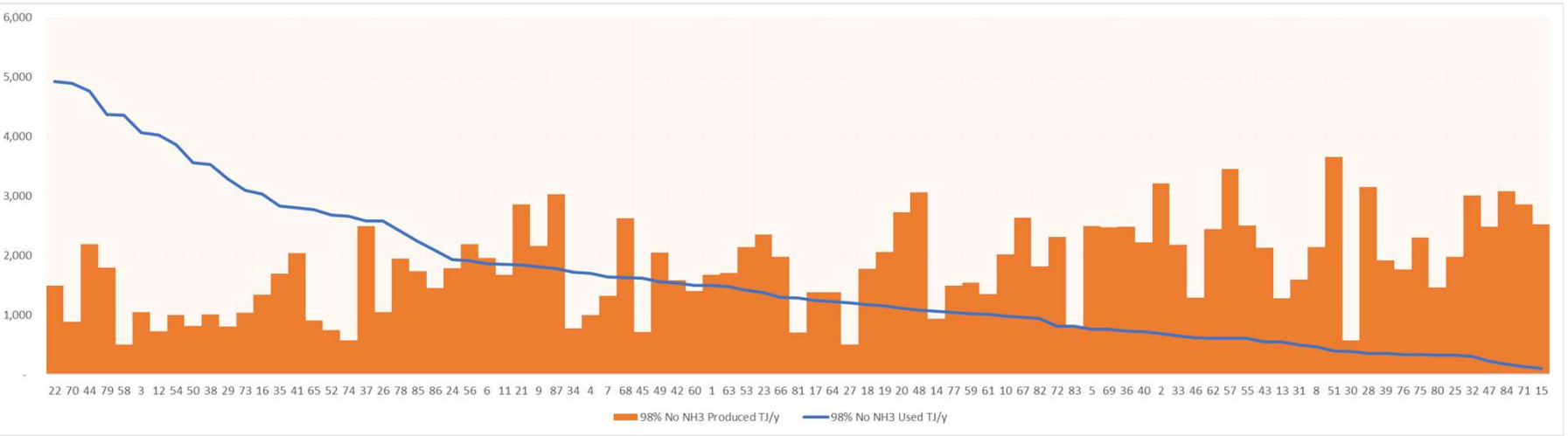
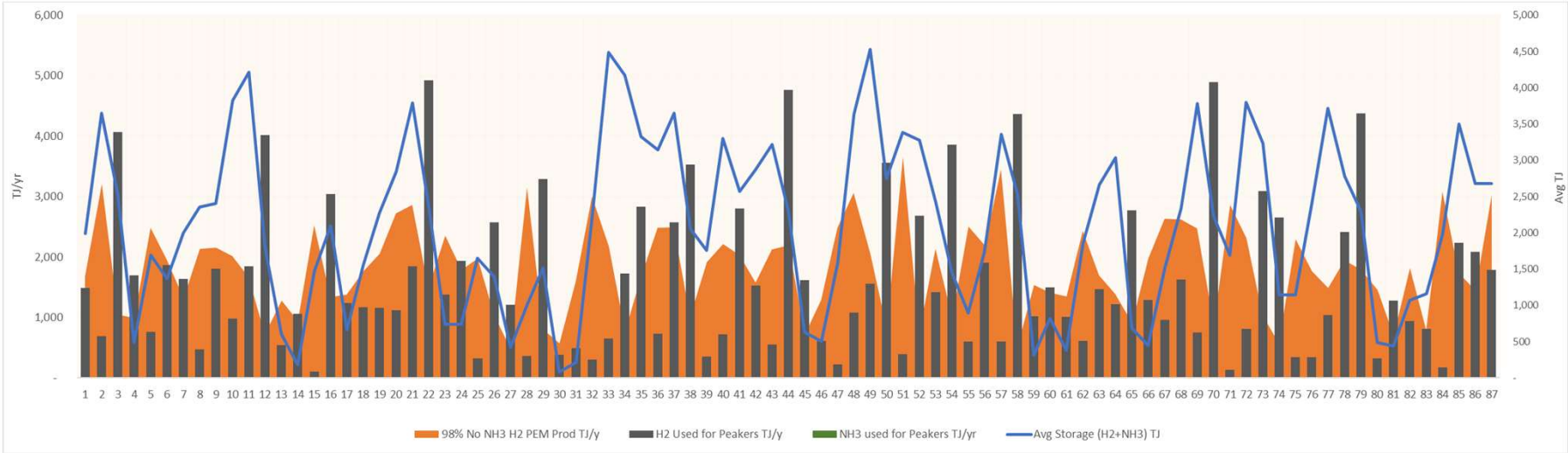


Ahuroa Only - Stratford power station

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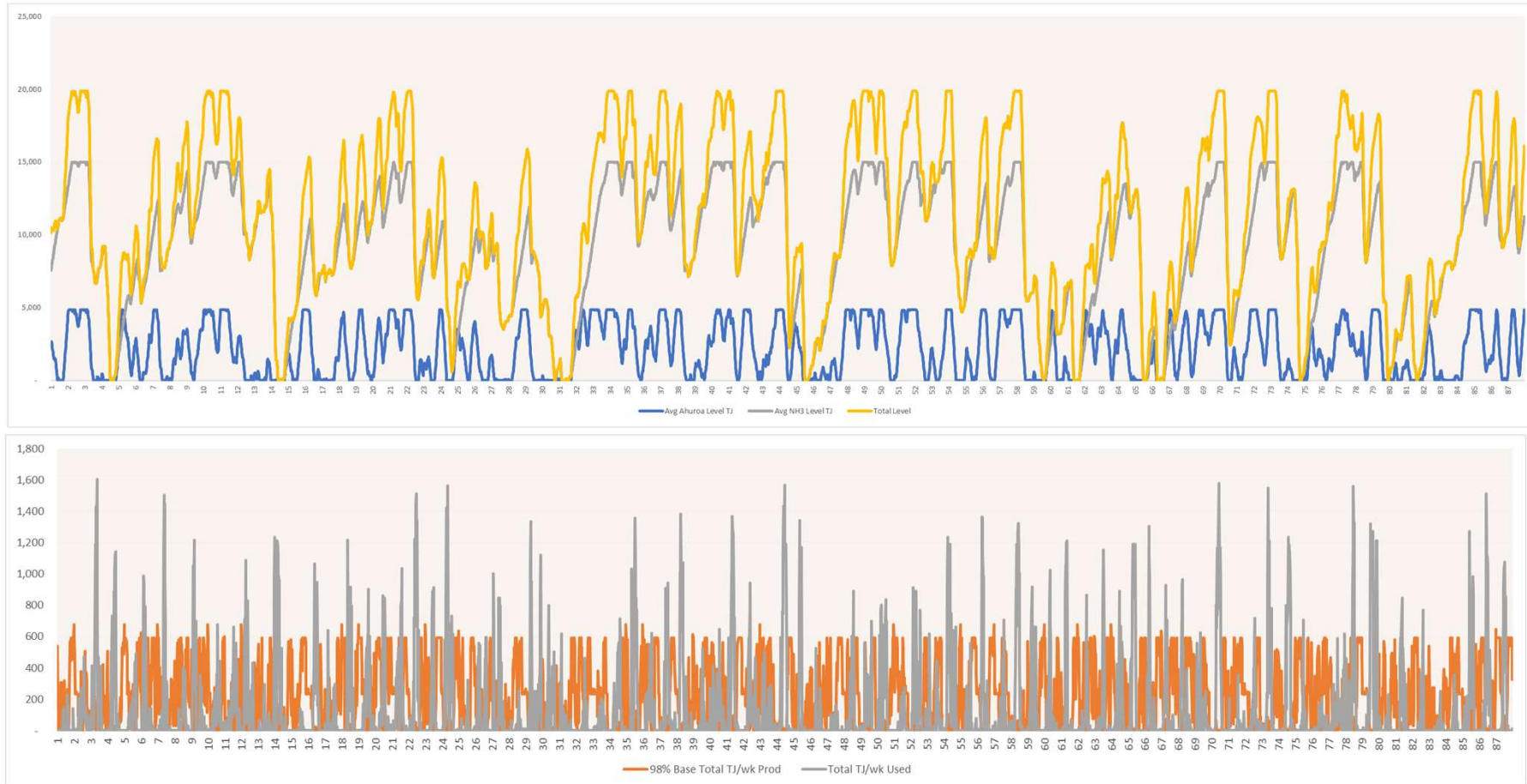


Annual Distributions : Ahuroa only

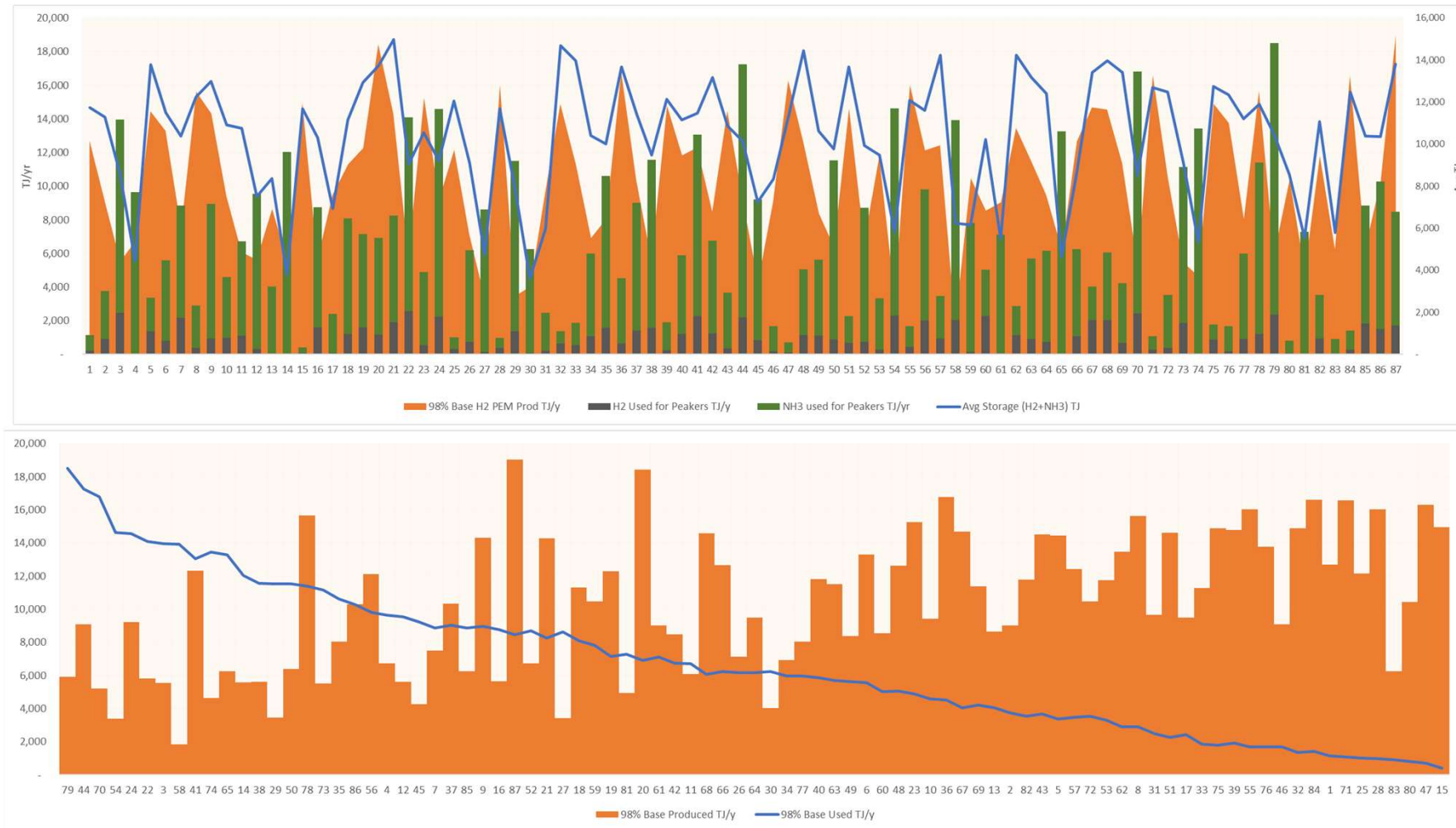


Base case : 20PJ storage (15PJ of NH₃ and 5PJ of H₂)

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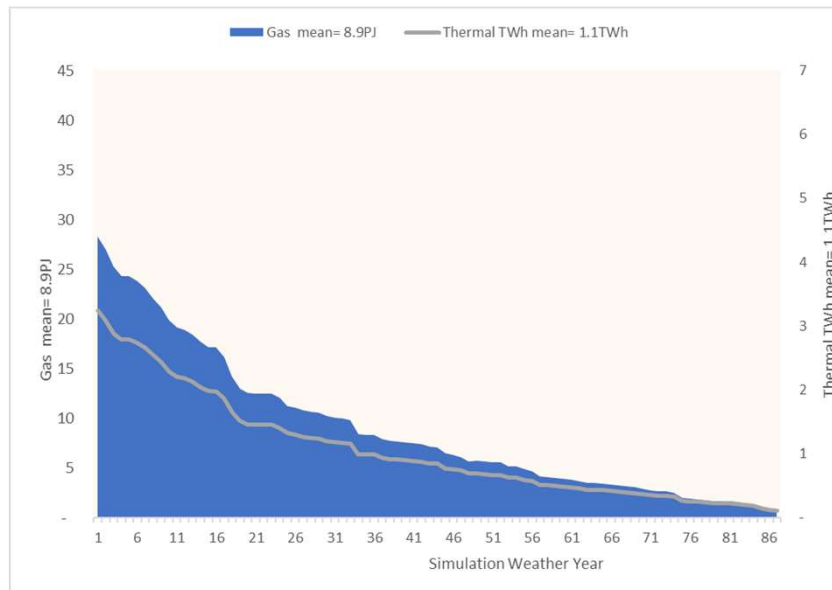
Annual Distributions: Base Case 20PJ storage



Annual thermal demand curves PJ and TWh per weather year

JC²

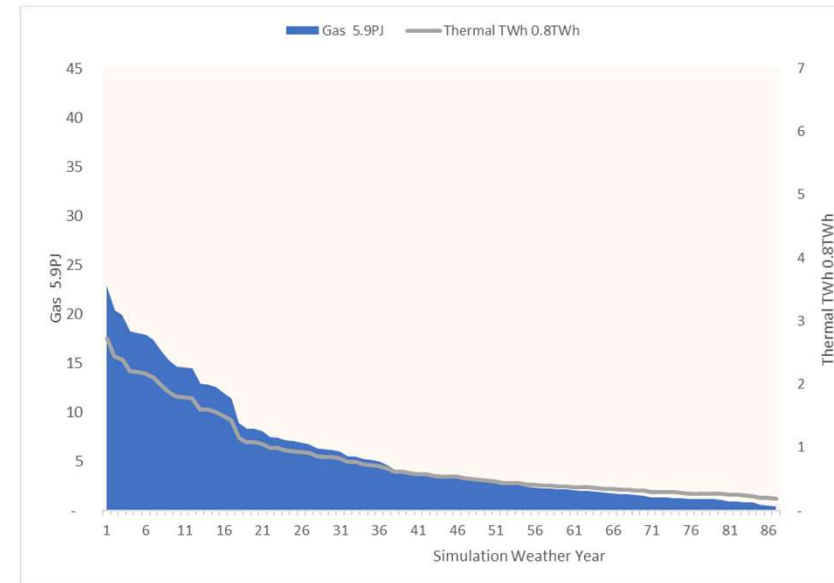
97.9% renewable - no E3P and Cogen - 920MW of peakers



Includes :

- E3P and Cogen retirement
- 920MW of gas/oil peakers

98.6% renewable - Wind and solar overbuild - 820 MW peakers



Includes extra:

- 820 MW gas/oil peakers.
- 150MW batteries (12 hour)
- 250 MW large scale solar
- 126MW wind
- 30MW geothermal
- Wind spill approx. 1200GWh

Caveats and Disclaimer

Limitations and Caveats

- The indicative analysis is based on a stand-alone simulation of the operation of the Ahuroa and ammonia storage facilities based on relatively simple operating rules with generation trigger prices tuned to ensure most long run (dry year) backup requirements are met, and hydrogen production trigger prices to give low production costs.
- There are limitations:
 - It is not guaranteed that all the demand for dry year back-up is met as the simulated results have some sequences which reach zero combined storage even with 20 or 25PJ storage. In these situations there may need to be additional demand response.
 - The impact of these projects on the EMarket simulated prices are ignored. There may be an increase in prices when there is extra demand for H₂ production, particularly if this extra demand exceeds wind “spill”.
 - The hydrogen production and storage use operating rules are reasonable heuristics but are not fully optimised.
 - There are uncertainties concerning the technology efficiencies, costs assumed as significant improvements above current levels are built into the analysis.

Disclaimer

- The information and opinions expressed in this presentation are believed to be accurate and complete at the time of writing.
- However, John Culy does not accept any liability for errors or omissions in this presentation or for any consequences of reliance on its content, conclusions or any material, correspondence of any form or discussions arising out of or associated with its preparation.

ICCC Modelling: Pumped hydro storage - Lake Onslow option analysis

Final Slides: John Culy

Introduction and Summary

- **This report examines the likely costs and benefits of a hydro pumped storage scheme in the South Island of New Zealand.**
 - This involves a 15-24km tunnel, underground power/pumping station and new dam/s to create a storage reservoir in the Onslow/Manabourn basins at an elevation of 700-800m. This can provide 1000 to 1500MW capacity with 4 to 12 TWh of storage capacity.
 - **The possible design and cost estimates are based on a variety of sources including:**
 - Various notes by Bardsley et al and a 2019 PHD thesis Majeed (2019) supervised by Bardsley.
 - Preliminary cost estimates for the full Lake Onslow/Manabourn scheme prepared by PB Power in 2006 for the Electricity Commission.
 - A 2018 review of the potential by Sapere Research Group for the Productivity Commission.
 - **This assessment assumes a small scheme with 1000MW capacity and 5TWh storage.**
 - **The estimated costs for an underground power station and tunnel are benchmarked against the costs estimates for the 2000MW Snowy 2.0 pumped storage project in Australia and a 1985 completed 640MW pumped storage project in Norway with around 7-8TWh storage capacity.**
 - Snowy 2.0 is a project with a tunnel and underground power/pumping station, but does not include a new hydro storage dam as it utilises an existing (but much smaller) reservoir with a similar relative elevation. The project is around twice the capacity and hence requires a larger tunnel diameter and underground power station cavern. It has gone to tender and the EPC contracts are close to being finalised.
 - The Norway project has a larger storage capacity, but a lower MW capacity, lower hydraulic head and a shorter 10km tunnel.
 - **A capital cost range based on the modified original costing and external benchmarks is around \$NZ3.2 ± 1.0 billion including transmission upgrades.**
 - **An indicative stand-alone evaluation of this project is based on the Middle of Road, Business as Usual, EMarket market simulation results and prices:**
 - This suggests that a generation capacity factor of around 17% and a pumping capacity factor of 22% might be achieved and this could displace around 0.6mt of emissions per year at a carbon abatement cost of around \$250 ± 100/t.
 - This simplified evaluation ignores some additional benefits from reduced spill at other hydro reservoirs and provision of ancillary services, but also some negative impacts on the operation of the existing Clutha hydro stations and on possible impacts arising from transmission constraints and losses.
 - It is noted that there are very significant consenting and commercial risks associated with a project of this nature and large size.

Earl Bardsley (University of Waikato), Bryan Leyland (LCL Ltd), Sarah Bear (URS Ltd) *A large pumped storage scheme for seasonal reliability of national power supply* Presentation to the EEA Conference.

Majeed, M., 2019. Evaluating the potential for a multi-use seasonal pumped storage scheme in New Zealand's South Island. PhD thesis, University of Waikato

New Zealand - Lake Onslow Pumped Storage

Illustrative Design (Majeed 2019)

○ Lake Onslow

- A new 3.8km 80m earth dam would provide around 7 TWh of storage in the Onslow Basin, lake area 74km².
- 24km kilometre tunnel linking the new reservoir with the Clutha River at lake Roxburgh.
 - Pre-cast concrete lined low pressure 7.5-8.0m internal diameter through schist rock
- 1.3GW pump-generators located at 80 metres above sea level underground so as to avoid steel linings for lower portion of tunnel.
 - Operating head approx. 600-700m
 - Full pumping to generation with minutes

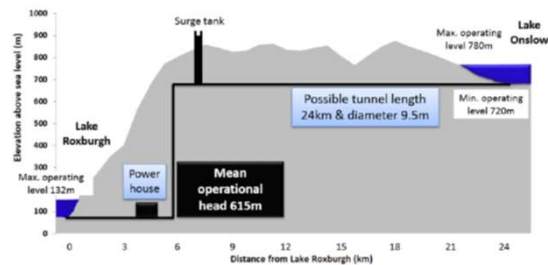


Figure 3.12 Cross section of the simulated Onslow PHES.

Clutha river
operating
range 300-900
cumec

185 cumec pumping,
240 cumec discharge



Figure 3.10 The hypothetical Onslow basin at 780 masl as the maximum extent of development and 720 masl as the minimum operational level.

Options

○ Storage could be:

- 12 TWh if the Manorburn basin used and 800m dam with 124 km² area
- 4 TWh if only Onslow basin and 60m dam

• Outlet

- 24 km into lake Roxburgh (provides flow regulation but impacts Contact's resource consents)
- 15km into Clutha below Teviot

○ Capacity could be 1.0 to 1.3GW

- 1GW would reduce tunnel diameter to 7m approx.

○



Figure 1 – The Onslow-Manorburn depression, showing maximum pumped storage reservoir development to 800 metre elevation in both Upper Manorburn and Lake Onslow basins.

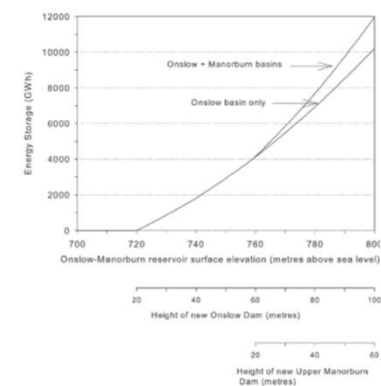


Figure 2 – Gravitational potential energy of a pumped storage reservoir in the Onslow-Manorburn depression. For both dams, the energy storage contribution is measured from zero at a 20-metre dam height on the basis of maintaining a permanent minimum lake area for environmental reasons.

Source: Majeed, M., 2019. Evaluating the potential for a multi-use seasonal pumped storage scheme in New Zealand's South Island. PhD thesis, University of Waikato

Lake Onslow - Additional Costs and Issues

Transmission Upgrade costs

○ Evaporative losses

- Majeed (2019) concluded that natural inflows into Lake Onslow would exceed evaporative losses, but maybe some reduction in Teviot river flow.

○ Transmission

- To get full value from pumped storage you need to get power at times of shortage to North Island
- Upgrade lines from Clutha to BEN
 - Approx. \$90-100m for thermal upgrade of Cromwell to Twizel, and duplexing of other lines (Transpower 2018 Transmission Planning report).
- Upgrade HVDC capacity to 1400MW (north)
 - Additional cost \$150m
 - Adding 4th cable and associated filters etc
 - Assuming done at same time as \$300m cable replacement project.

○ Total costs

- Capex NZ\$2.3b to \$4.0b (\$1.8 - 3.1/W) + transmission (\$0.25b)
 - Operating cost NZ\$12 to \$50m/yr
- Sapere suggested NZ\$1.8 to \$5.2b capex range.

Location and Geology



Figure 3.7 Geology surrounding the proposed scheme (based on Geology data GNS Science 2014) [91].

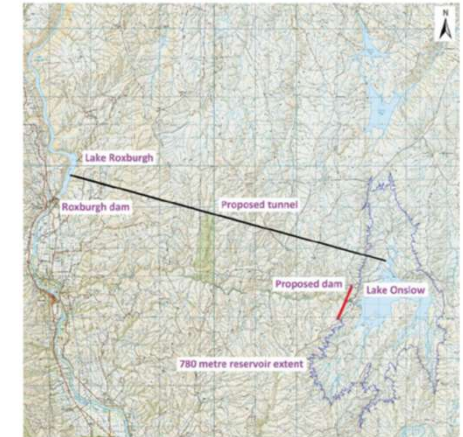
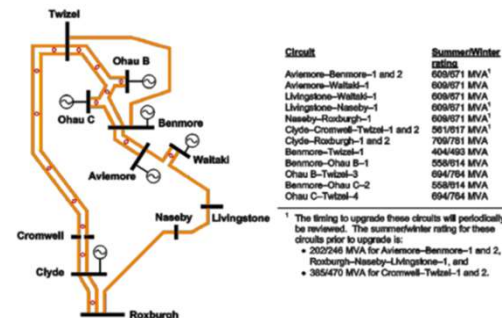


Figure 3.8 Location and layout of the hypothetical Onslow PHES at the maximum extent of development of the upper reservoir 1:250,000 scale map.



Australia - Snowy 2.0 Pumped Storage

Summary

Physical

- 2000MW and 80-176 hours of storage (360 GWh) operating head = 700m
- 27 km of 10m diameter concrete lined underground tunnels and underground power station
- 6 reversible Francis pump-turbine and motor-generator units (3 synchronous and 3 variable) - can swap from full pump to generate within minutes
- 76% round trip efficiency
- Simulated capacity factor $\approx 17\%$ output, $\approx 24\%$ pumping

Capital Cost

- A\$3.8-4.5b + \$1-2b (Transgrid for transmission) - Dec 2017 \$ terms
 - Spread over 7 years, 50 year economic life

Operating Cost

- FOM A\$5m/yr = A\$2.5/kW/yr and VOM = 1/MWh (brush gear replacement)

Stated Value - NPV @ 4.55% discount rate

- Conventional capacity value = A\$2.7b (or A\$1.36/W) (i.e. back a \$300/MWh cap)
- Renewable firming = A\$0.72b
- Retail diversification = A\$0.47b
- Storage value = A\$3.6b
- Ancillary services = A\$0.25b
- O&M & Tax = -A\$0.15b
- 8% equity IRR when funded by debt at average cost of 5.66%.

Charts

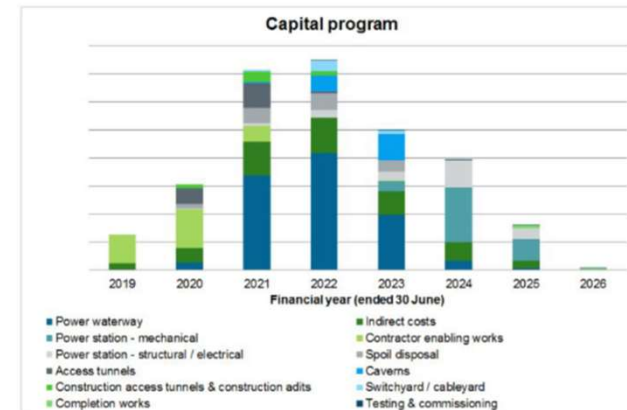


Figure 8: Capital program

Power Station Mechanical & Elec & structural & cavern $\approx 25\%$
 Tunnels & Enabling & Spoil $\approx 62\%$
 Other Indirect $\approx 13\%$

Comparison of Snowy 2.0 and Lake Onslow pumped storage

Comparison

	Units	Norway Saurdal	Australia Snowy 2	NZ Onslow	NZ Onslow small
Capacity	GW	0.64	2.00	1.30	1.00
Energy	TWh	7.76	0.35	7.00	5.00
Upper Reservoir level range	m	125		80	70
Lake Area	km ²	82		74	70
Tunnel Length	km	10.5	27	20	20
Tunnel internal diameter	m		9.0	8.0	6.8
Hydraulic Head (Avg)	m	465	650	615	650
Capital Cost Hist/Mid	NZ \$b 2018	\$1.80	\$4.46	\$3.15	\$2.80
Low	NZ \$b 2018		\$4.08	\$2.30	\$2.00
High	NZ \$b 2018		\$4.83	\$4.00	\$3.50
Transmission	NZ \$b 2018		\$1.6	\$0.3	\$0.3
Initial Filling	NZ \$b 2018			\$0.2	\$0.1
Capital Cost Hist/Mid	NZ \$/W 2018	\$2.8	\$2.2	\$2.4	\$2.8
Low	NZ \$/W 2018		\$2.0	\$1.8	\$2.0
High	NZ \$/W 2018		\$2.4	\$3.1	\$3.5
Transmission	NZ \$/W 2018		\$0.8	\$0.2	\$0.2
Capital Cost Hist/Mid	NZ \$/kWh 2018	\$0.4	\$6.4	\$0.3	\$0.6
Low	NZ \$/kWh 2018		\$5.8	\$0.3	\$0.4
High	NZ \$/kWh 2018		\$6.9	\$0.4	\$0.7
Total	NZ \$b 2018		\$4.5		\$2.8
Water way & Tunnels	NZ \$b 2018		\$2.8		\$1.3
Power House & Cavern	NZ \$b 2018		\$1.1		\$0.6
Dam & Land purchase	NZ \$b 2018				\$0.7
Other	NZ \$b 2018		\$0.6		\$0.3

Commentary

○ Snowy 2.0

- Has 2x capacity 2000MW compared with 1000MW
- Has similar head to Onslow at around 700m
- Has slightly longer tunnel 27km with 9m versus 15-24km with 7m internal diameter for Onslow.
- Has pre-cast concrete lined tunnels like Onslow
- Does not have the extra cost of a 3.8km, 70m high dam

○ Onslow (small) estimated cost based on Snowy costs

- Assumes tunnel cost is scaled by volume and power house by MW
- plus cost of 70m concrete faced rock dam and land purchase NZ\$0.7b
- **Total of NZ\$2.8b (i.e. same \$/W as large pumped storage in Norway)**
 - plus incremental transmission say NZ \$0.3b - for Clutha to BEN capacity and increase of HVDC to 1400 MW, plus NZ \$0.1b cost to fill to 3TWh
- **Grand total NZ\$3.2b ± 30% (± \$1.0b)**

○ Risks:

- Large consenting risks, potential conflict with other consents on Clutha
- Large single project compared to many small overbuild projects in North Island
- Could face significant transmission costs/constraints compared to North Island option
- Uncertain impact of Onslow on other hydro and on pricing outcomes
- Earthquake risks
- Difficult for any single party in the market given size and risks

Indicative Evaluation

Base Valuation

○ Base Valuation

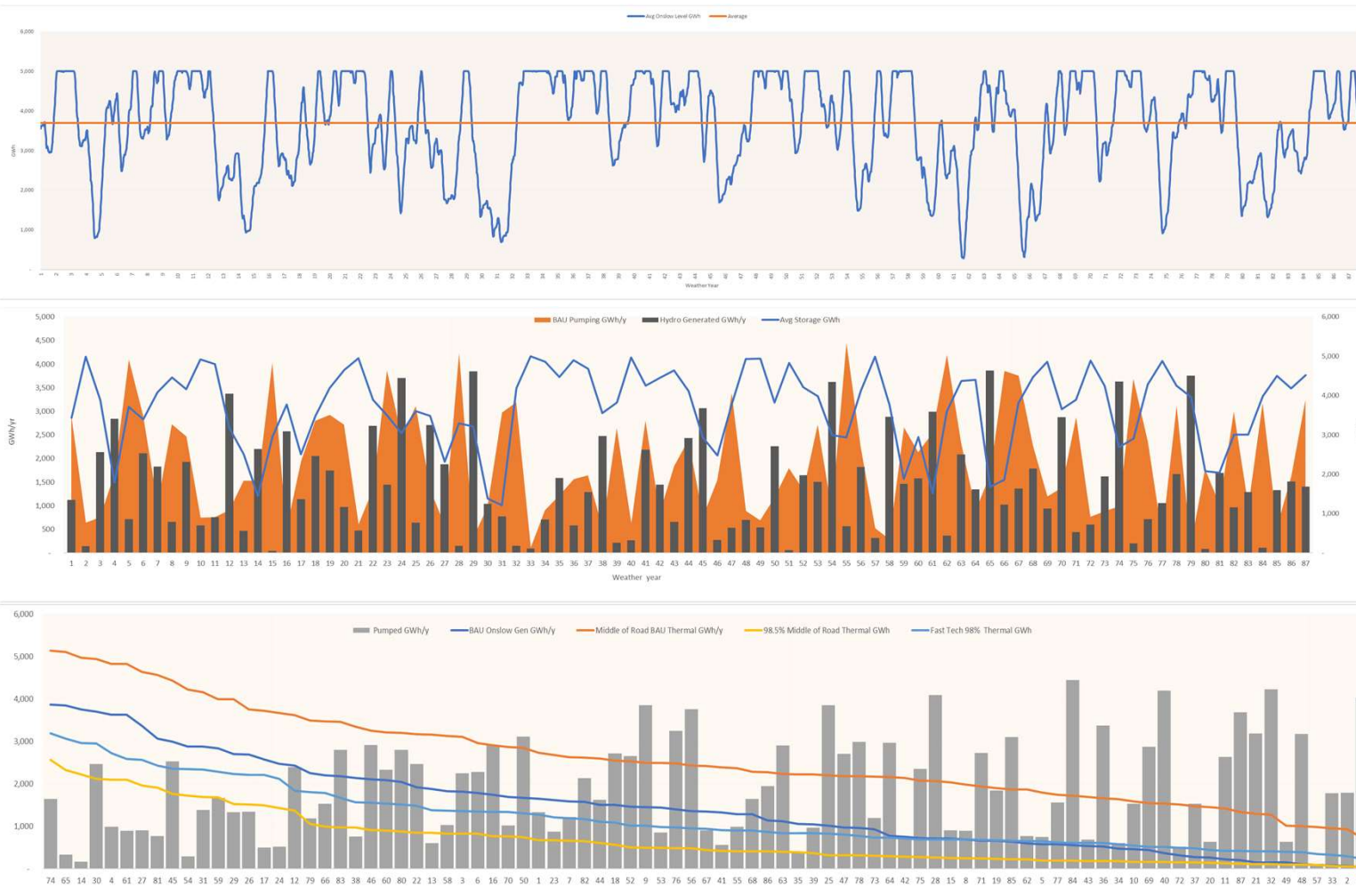
- **Assume:**
 - \$3.2b capital cost including incremental cost of transmission to enable 1400 MW transfer capacity to the North Island and cost to fill
 - 50 year life capital recovery factor 8.5% (to give 8.0% post tax nominal merchant WACC)
 - \$16m/yr operating cost (0.5% of capital)
 - \$3.5/MWh variable transmission costs for pumping
 - 5 TWh storage (Onslow basin only)
 - 1GW capacity (pumping and generating)
 - 78% round trip efficiency (75% for dry year and 80% for cycling)
 - Middle of Road Business as Usual South Island price duration curve in 2035 and limits from HVDC operating to 1400MW max
 - This has gas peaker and CCGT capacity of 1GW and average generation of 1.5TWh/yr that could be replaced by Onslow Pumped Storage
 - Pumped storage is operated to pump trigger prices around \$45-70/MWh and generate trigger prices around \$80-180/MWh depending on storage.
- **Ignore:**
 - The impact of Onslow pumped storage on the BAU price duration curve
 - i.e. use of stand alone model of pumped storage operation based on price triggers and HVDC constraints
 - Impact of constraints in Clutha river downstream at Roxburgh
 - Impact of marginal losses and transmission constraints other than HVDC.
 - Potential benefits from reduced spill etc from impact of Onslow storage on the operation of other South Island storages
 - Potential benefits from ancillary services (possibly \$10m/yr)

Results

- Pumping CF = 21.5% - 1.9TWh - avg cost \$30/MWh
- Generation CF = 16.6% - 1.5TWh avg value \$158/MWh
- Annual gross margin = \$167m/yr or \$167/kW/yr
- The annual capital cost = \$290m/yr or \$290/kW/yr
- The cost of delivered electricity is approx. \$243/MWh for 16.6% capacity factor operation (capital cost recovery and power purchase).
- There is an operating loss of \$123m/yr but can save 0.61mt of emissions/yr (E3P & gas peakers)
 - The implied incremental abatement cost is \$200/t (note that the BAU already includes a \$50/t carbon price) so the total is \$250/t.
 - The range of abatement costs for a variation of 30% \pm \$1.0b is approx. \pm \$100/t.

Results Charts

JC²



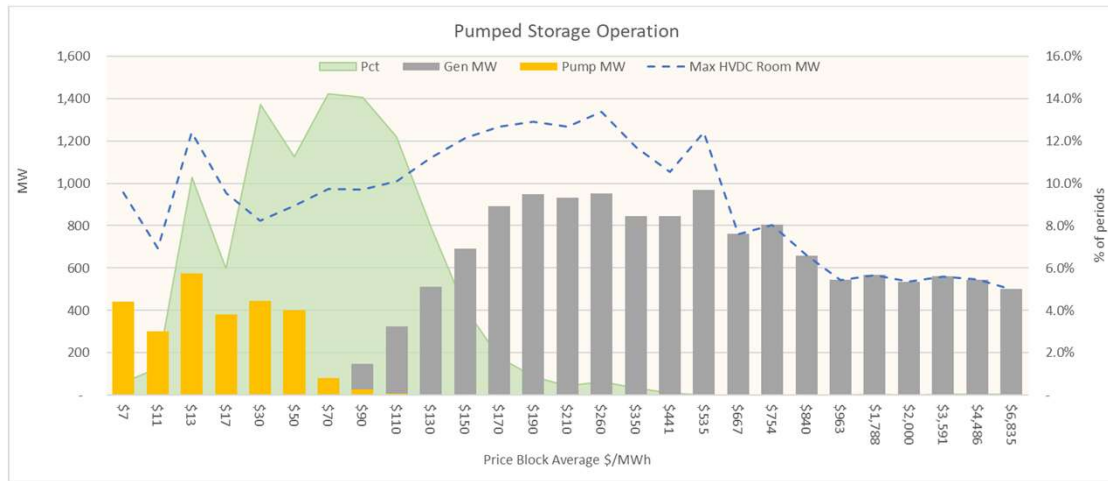
Pumped storage weekly levels stay above zero and average 3.8TWh

Onslow meets around 2/3 of Middle of road BAU peaking and E3P thermal demand.

Note that Onslow can meet >60% above the 2035 Middle of Road 98.5% renewable, residual thermal demand.

It can also meet 20% more than the residual thermal demand from the Fast Tech High Demand 98% renewable, residual thermal demand.

Pumped Storage Operation and HVDC constraints



- The chart shows pumping and generation profile of Onslow by Benmore Price block.
 - The Benmore prices are those for the Middle of Road BAU scenario
 - This does not account for impact of Onslow on dispatch of other hydro in the SI. Ideally Onslow should be modelled as a part of the system.
- Note: pumping for prices below \$70-80/MWh and generation for prices above \$80-100/MWh
- The impact of northward constraints on the HVDC is shown by dotted line
 - Note that this is after expansion of capacity to 1400MW (with 4th cable).
 - At very high prices (when most other SI hydro is operating to capacity) the HVDC will limit incremental generation at Onslow to around 600MW.
 - The extend of this HVDC limit will depend on SI demand and generation - this is approximated by modelled HVDC operation before the expansion of HVDC
 - It is possible that at very high prices Onslow generation may simply displace other SI hydro when the HVDC is expanded. This needs to be investigated with additional integrated modelling.

Caveats and Disclaimer

Limitations and Caveats

- The indicative analysis is based on a stand-alone simulation of the operation of the pumped storage facility based on relatively simple operating rules with pumping and generation trigger rules, tuned ensure the storage is fully used to cover both short run and long run (dry year) backup requirements.
- There are limitations:
 - Only the HVDC limits and losses are accounted for. Other potential transmission constraints are ignored.
 - The potential downstream constraints at Roxburgh are ignored.
 - The impact of this project on the E-market simulated prices are ignored.
 - The interactions between the operation of the pumped storage and other storage are ignored. There may be potential spill savings at other reservoirs in the South Island.
 - Ancillary service revenues are ignored.
 - The pumped storage operating rules are reasonable tuned heuristics but are not fully optimised.
 - It is difficult to determine the net impact of these limitations on the conclusions as some are negative and some are positive.

Disclaimer

- The information and opinions expressed in this presentation are believed to be accurate and complete at the time of writing.
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