Meridian.

Southern Green Hydrogen and Dry-year Flexibility

Power system needs; and Notional contract structure

EPOC Winter Workshop
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Green hydrogen and dry-year flexibility

The Southern Green Hydrogen joint venture between Meridian and Contact has shortlisted potential partners to develop a large-scale green H_2 (GH_2) facility in Southland:

- Commerce Act protocol in force;
- Exciting decarbonization potential, possibly both GH_2 *and* GAl;
- Opportunity to provide flexibility (sustained down) to the power system;
- In time, intermittency (up/down) and grid services could be considered.

This is novel territory for all potential partners, for the power system, for power market design, and for regulators.

To bring the idea further to life we move beyond a general description and consider **hypothetical** contractual terms of engagement and how they might interact with Aotearoa's power system, today and in the future.

For an illustrative GH_2 facility, we focus here today on :

1. How might a contract for supply and a contract for flexible interruption be structured?
2. How might these structures have performed historically, over 2000-2022?
3. What are the dry-year needs of the power system in a future 100% renewable power system and how do they line up with GH_2 production, demand interruption, and contract incentives?

SOUTHERN GREEN HYDROGEN

Delivered by Meridian and Contact

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Notional GH_2 facility:

- 600MW
- 95% load factor
- 5TWh energy
- 100kT of GH_2
  = 500kT of ammonia
- upfront capital $2b
- annual costs: power + O&M

Global potential of green hydrogen

A large increase in hydrogen use in a decarbonized world is possible, especially if GH_2 use-cases become wide-spread and varied, and if production costs continue to fall.

- Potential to fundamentally alter the nature and geopolitics of global trade and energy flows.

GH_2 use-cases are nascent but could include:

- Chemical feedstock: methanol, ammonia, hydrogen, urea
- Transport: heavy road, light fleet, aviation, shipping
- Reticulated gas replacement (heating, cooking, etc)
- Power production
- Green steel

Along-side green credentials, the cost of production is key:

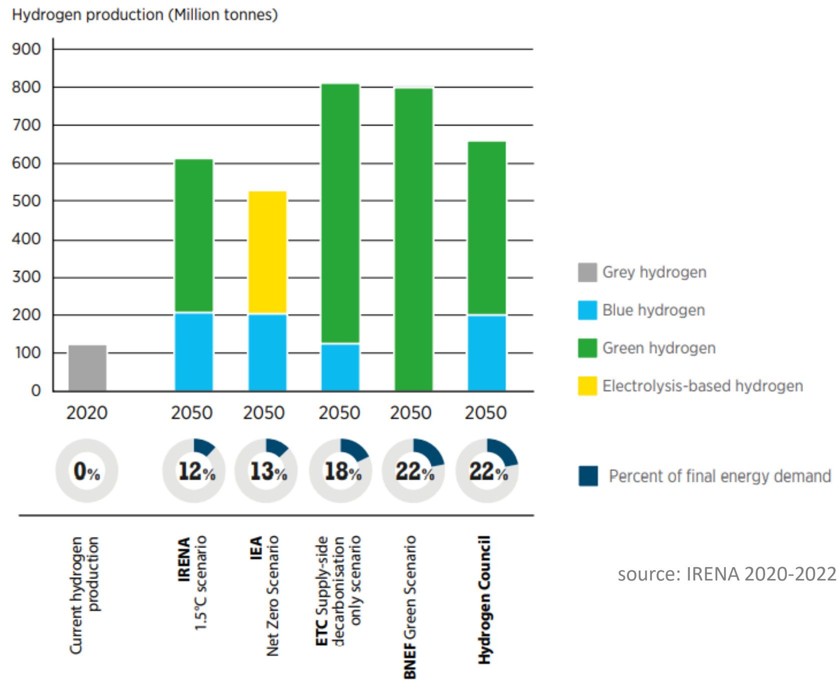
- Grey hydrogen in 2022: USD \$1-2/kg
- Green hydrogen in 2022: USD \$3-6/kg

Electrolyzer costs have fallen significantly: by 60-70% for both PEM & AEL since 2005:

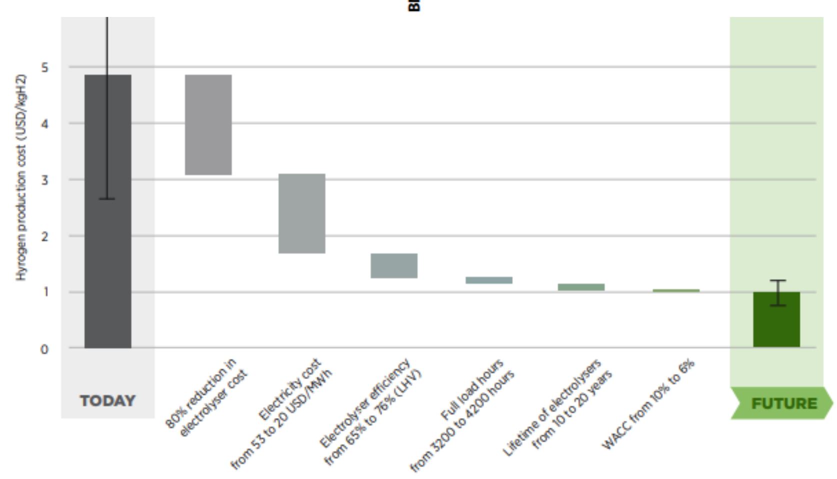
- Renewable energy costs have dropped: by 90% for grid-solar, 50% for on-and-off-shore wind since 2010.
- Further large cost reductions across all technologies are expected.

Ultimately for SGH and for NZ, understanding any new global energy market matters less than finding a stable counterparty.

Figure 1.1 Estimates for global hydrogen demand in 2050



source: IRENA 2020-2022



Note: 'Today' captures best and average conditions. 'Average' signifies an investment of USD 770/kilowatt (kW), efficiency of 65% (lower heating value – LHV), an electricity price of USD 53/MWh, full load hours of 3200 (onshore wind), and a weighted average cost of capital (WACC) of 10% (relatively high risk). 'Best' signifies investment of USD 130/kW, efficiency of 76% (LHV), electricity price of USD 20/MWh, full load hours of 4200 (onshore wind), and a WACC of 6% (similar to renewable electricity today).

A contract for supply and a contract for dry-year interruption

How might GH_2 supply and the dry-year needs of the power system be delivered?

A series of financial contracts is cleanest and clearest:

- Financial only
- Simple, clear structures
- Contract terms made public, and/or shared with regulators
- Key terms associated with identifiable “NZ-inc” data
- Financial incentives on both sides of the transaction will influence, but not determine, physical behaviour

A contract of this scale will be highly visible and prominent especially during dry-years.

The nature of what is being suggested needs to be acceptable politically, to the public, to our regulators, but also still work commercially for all parties.

1. **Baseload CfD**
   - 24x7 simple price and volume in Southland
   - Standard baseload ISDA structure

2. **An option on a two-way swap (swaption)**
   - Series of tranches of escalating price and depth
   - Various notice periods for call

3. **A contract ‘reservoir’ to limit use of the swaption**
   - Simple limit on energy called over contract lifetime
   - Plus, possible limit on use in any given year
   - Refill mechanism by mutual agreement

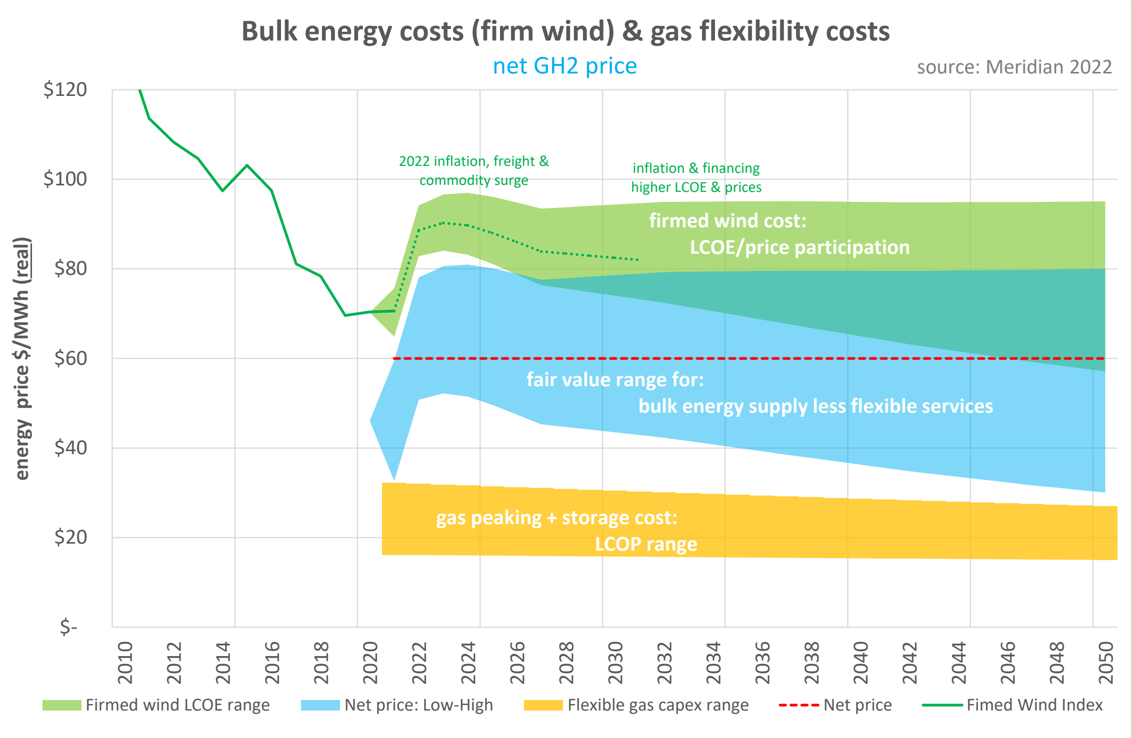
Contract structure rationale

This package is firmly the result of two separate elements:

- The cost of <u>bulk energy</u> >> sold *to* the facility.
- Less, the value of the <u>right to use flexibility</u> << bought *from* the facility.

CfD payments that accrue when flexibility is called would be additional to this.

While the net position is relevant to the GH_2 producer, the power system can legitimately view the power delivered to the GH_2 facility as being the amalgamation of two products.



One approach *could* be to view:

- <u>Bulk energy</u>: priced at the cost of *firmed* new wind
  = $75-90/MWh post current commodities surge
- <u>Right to use flexibility</u>: priced at new peak capacity costs
  = currently a gas turbine at ~$15/MWh
  but with more cost needed ($10-15/MWh) to
  create additional up-stream fuel flexibility

prices can be associated with identifiable and efficient new build costs. But might be fixed, or indexed in various ways, or share of profits, or etc…

Key terms illustrated and incentives

1. Baseload CfD: 600MW @ $75/MWh

- LCOE for Southland wind circa 2027, firmed[1]
- we expect baseload spot prices to be close to firmed LCOE, on average in the long-run

2. Swaption: 6 x 100MW @ $165 - 415/MWh

- in equal price steps of $50/MWh
- with a fixed option fee of $15/MWh ($80m pa)

  = the levelized capital and annual fixed costs for 600MW of new gas turbine[1]
- swaption strike-price notionally starts at [heat rate] x [flex gas price] increasing to [heat rate] x [diesel price] [2]
- assumes the capacity cost / price >=$15/MWh in any future capacity or firming market

3. Contract reservoir: 5-10TWh

- 5% of expected consumption x 20 years for a 600MW facility, with possible maximum annual limits
- arbitrary, but creates comfort for the GH_2 producer
- how and when this is used is at the discretion of the swaption holders

Incentives on each party are financial only:

- When NZ reservoirs are low, power suppliers are relying on GH_2 consumption to fall in line with financial incentives created by high power prices <u>and</u> a swaption call:
  - Otherwise, the GH_2 producer becomes exposed to high spot prices for a portion of their load
- The GH_2 producer is relying on the power suppliers to follow incentives; only calling the swaption when power prices are high and above swaption strike-price (eg when lakes are low)
  - Otherwise, the power supplies are exercising an out-of-the-money CfD

Associating key contract numbers to the scale and unavoidable costs of suppling new energy and to the costs of new discretionary firm energy is both orthodox and increases the likelihood that the commercial arrangements are acceptable and durable.

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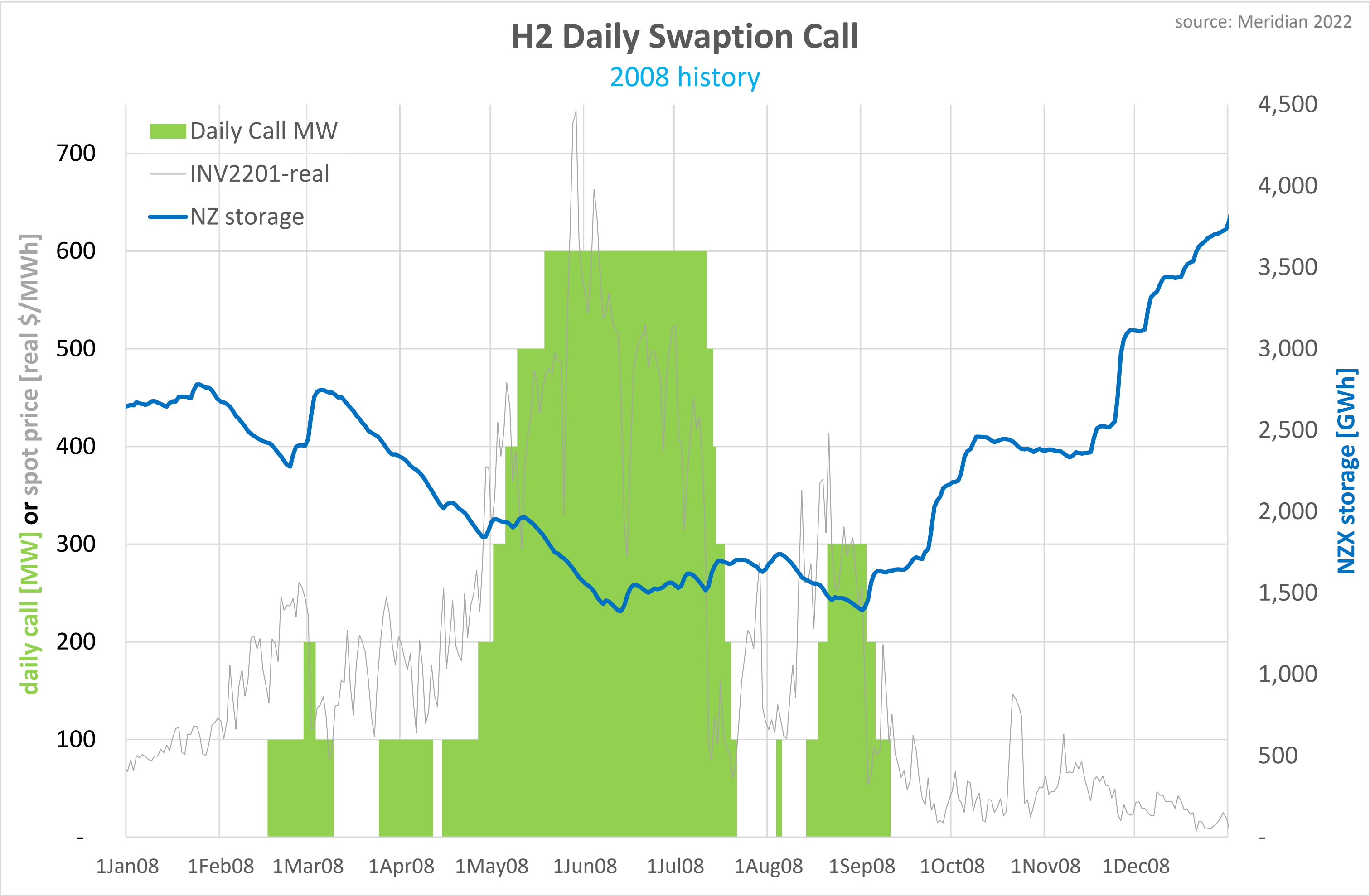
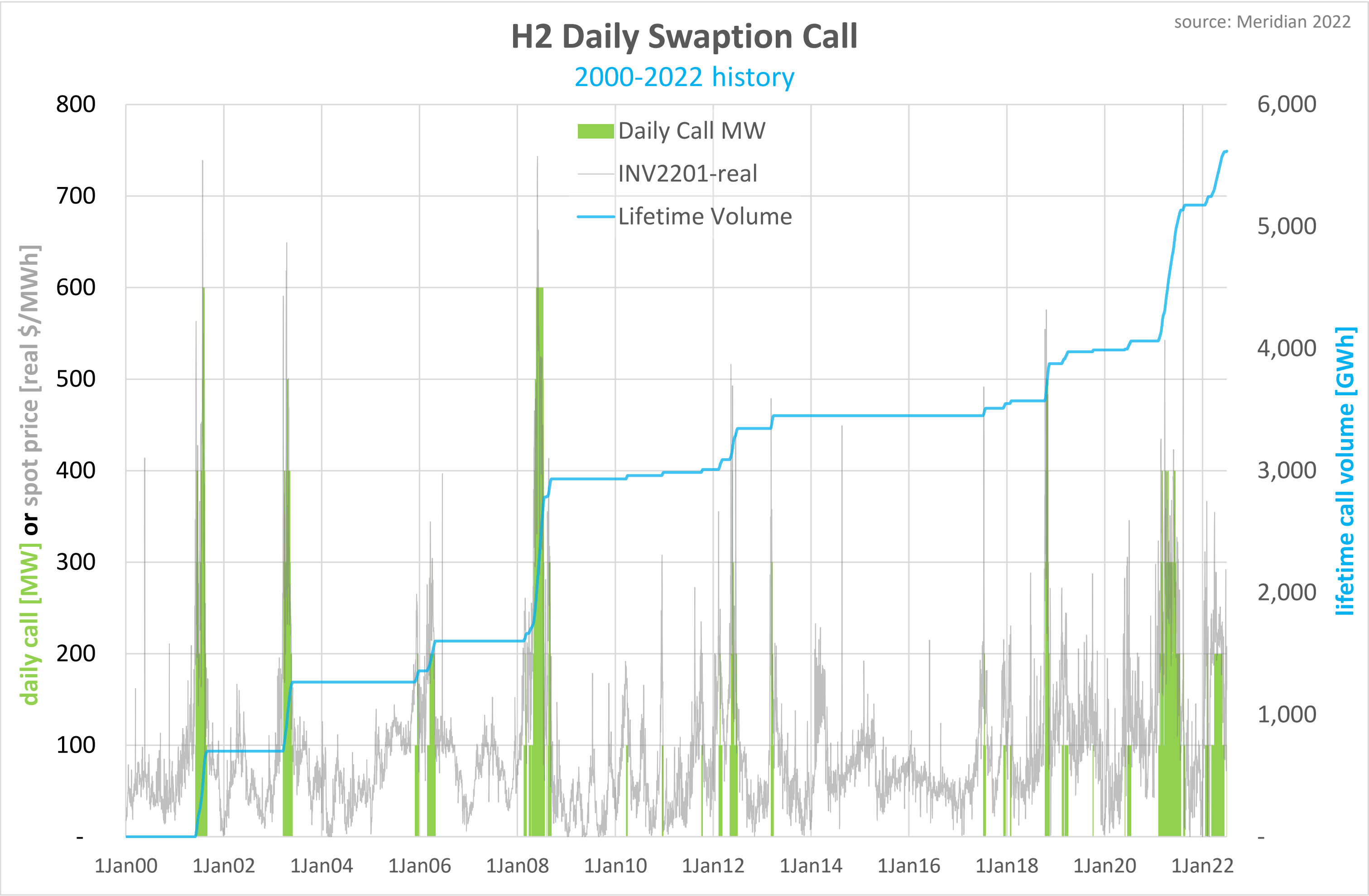
[1] MBIE costs estimates, adjusted for 2020-2022 inflation

[2] Analyst Taranaki gas costs (Jardens)

Historical swaption performance: How might 2008 have looked?



Historical swaption performance: How might 2000-2022 have looked?



Historical swaption performance detail

source: Meridian 2022

Historically, these **hypothetical** swaption calls align closely to initial expectations and to the physical needs of a 100% renewable future (next page). Assuming a simple rolling 2-week price trigger, since 2000:

- 6TWh of swaption called
- ~5% of total consumption on average
- 1,300GWh would have been called in 2008

In addition to the fee, swaption CfD payments to GH_2 facility would have been significant, IF associated physical load is reduced:

- $54m on average
- $345m in 2008

(Costs of lost production and baseload CfD payments also need to be considered)

Swaption purchasers benefit from in-the-money CfD payments:

- $20m on average
- $190m in 2008

As well as being a clear risk management tool, if physical load is reduced, this can help arrest storage decline

Historic swaption summary

Idx	History *cal*	INV2201 *$/MWh*	Contract *Reservoir*	Annual Call *GWh*	Fixed CfD *$m*	Swap CfD *$m*
1	2000	$ 52	**5,000 GWh**	-	$ -	$ -
2	2001	$ 136	5,000 GWh	701 GWh	$ 170	$ 71
3	2002	$ 58	4,299 GWh	-	$ -	$ -
4	2003	$ 126	4,299 GWh	566 GWh	$ 132	$ 44
5	2004	$ 45	3,733 GWh	-	$ -	$ -
6	2005	$ 109	3,733 GWh	91 GWh	$ 16	$ 2
7	2006	$ 116	3,642 GWh	245 GWh	$ 45	$ 12
8	2007	$ 72	3,397 GWh	-	$ -	$ -
9	2008	$ 191	3,397 GWh	1,326 GWh	$ 343	$ 187
10	2009	$ 37	2,071 GWh	-	$ -	$ -
11	2010	$ 74	2,071 GWh	53 GWh	$ 9	$ 0
12	2011	$ 68	2,018 GWh	24 GWh	$ 4	-$ 0
13	2012	$ 110	1,994 GWh	335 GWh	$ 64	$ 13
14	2013	$ 74	1,659 GWh	106 GWh	$ 21	$ 3
15	2014	$ 86	1,553 GWh	-	$ -	$ -
16	2015	$ 75	1,553 GWh	-	$ -	$ -
17	2016	$ 57	1,553 GWh	-	$ -	$ -
18	2017	$ 90	1,553 GWh	98 GWh	$ 17	$ 1
19	2018	$ 111	1,455 GWh	326 GWh	$ 77	$ 26
20	2019	$ 119	1,129 GWh	113 GWh	$ 19	$ 1
21	2020	$ 101	1,016 GWh	74 GWh	$ 12	$ 1
22	2021	$ 173	942 GWh	1,114 GWh	$ 238	$ 70
23	2022	$ 186	- 172	891 GWh	$ 80	$ 15
		$ 98	- 1,063	**<< re-fill ?**	$ 1,246	$ 445

Future demand response in a 100% renewables system

Assuming financial and physical alignment, we see similar overall performance in a 100% renewable future to that implied by the historical financial incentives:

- Distinctions can be made between being *always* available and only available in a dry conditions.
- Flexing up to help with intermittency management can also be considered, during days of surplus renewable supply, eg via a “put” instead of a “call”.

Concept Consulting (and Meridian) have both assessed large scale demand response as having one of the lowest producer-costs for NZ/Aotearoa in a decarbonized future power system.

One key question for the financial owners of large-scale flexibility, is do they expect to see an energy-only market design return $15-30/MWh of cost?

- History suggests $5-10/MWh
- But as thermal plant retire and more wind/solar/geo are developed, system flexibility has to come from somewhere. But at what cost?

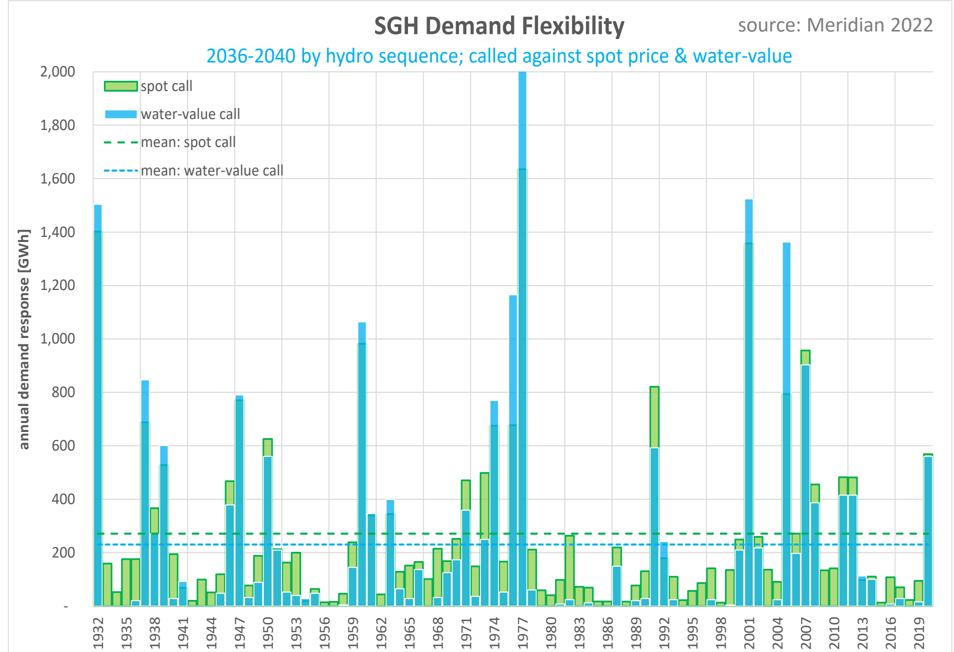
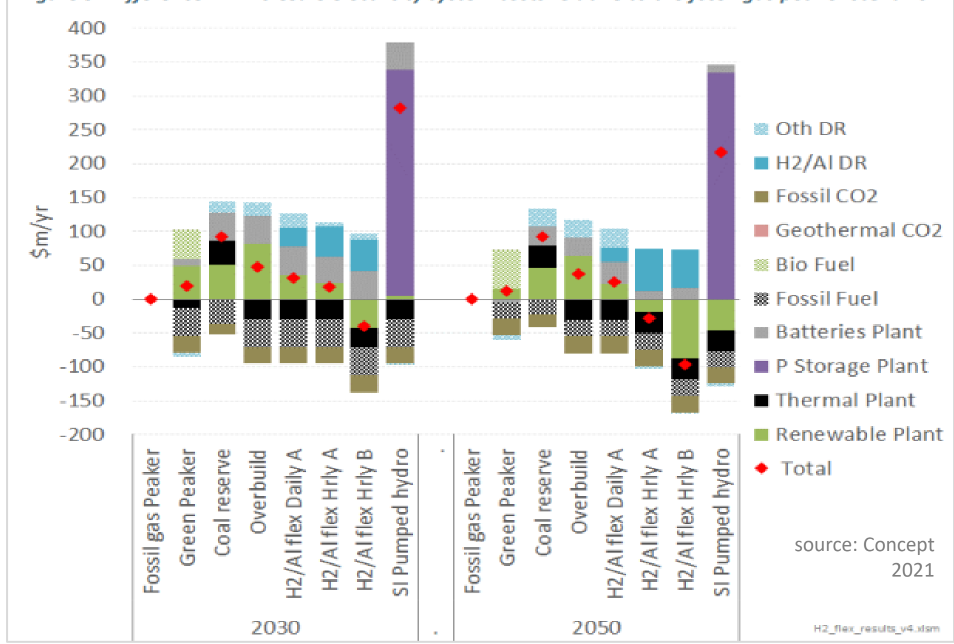


Figure 9: Difference in wholesale electricity system costs relative to the fossil gas peaker scenario



Key points

SGH supply and dry-year contract structures

- SGH will sell baseload energy at one price to the GH_2 facility and buy back the right to use flexibility at a different price; avoiding bundling:
  - The baseload sell CfD and the flexible call on a buy CfD are financial only.
  - Avoiding dictating outcomes; using incentives to create a win-win.
- Whenever flex is called, both parties can make money against spot prices via CfD structures:
  - For the GH_2 facility this only occurs if their load is physically reduced commensurately.
  - For SGH this only occurs if prices are high, lakes likely low. Helping arrest lake decline.

The demand response is intended to be commercially palatable, simple, and defendable both publicly, and to multiple regulators increasingly focusing on 'efficient and fair' outcomes.

Role in the future market

- Do we need to believe in a global GH_2 future? Certainly, counterparties are very engaged.
- Helps resolve the chronic Tiwai uncertainty that has long overshadowed the market.
- The SGH flexibility is amongst the cheapest options to allow Aotearoa/NZ achieve 100% renewable while securely managing dry years:
  - Avoiding *unnecessary* costs of over-sizing a solution like Onslow, levied across the consumers and the industry, is also good.
- If the flexibility product is made (relatively) transparent to the market, then we can also demonstrate that NZ's energy-only, market design has the potential to deliver on the energy trilemma needs of NZ.