Spreads, Scratches and Shadow Prices

Inside Electricity Hedge Markets in New Zealand and North America

Scott MacDonald

Trighill Consulting

About Me

- Moved to New Zealand in 2022 to help build the NZ Power desk for emhTrade/Bold Trading
- Commercial Market Making contract with EA
- Previously at private fund, financial participant in Eastern US power and gas markets
- Traded congestion products in NYISO, PJM, MISO (FTRs + Virtuals)
- Current Projects:
  - Development of Market Making software for NZ Gentailer
  - Build FTR trading desk for large Canadian Utility (2 GW gas/wind generation assets)

- Contact:
  - scott@trighill.com
  - 022 535 2711

Themes

- What innovations in the derivatives market will help facilitate the transition to renewables?
- Recent developments in New Zealand:
  - Super-peak contracts
  - Changes to the market making settings
- What can we learn from other jurisdictions?
- Focus on exchange traded products and FTRs, exclude spot market

Grid in transition reshapes risk

- Increasingly weather dependent system changes spot price formation
- Existing financial products to manage risk are not sufficient
- Need shaped hedges
- Motivating example: “Dunkelflaute”

Storage is the answer

- Pumped hydro
- Batteries in NZ
  - Rotohiko (35 MWh), Ruakākā (200 MWh), Glenbrook-Ohurua (200 MWh)
  - Huntly (200 MWh) in progress
  - Queue, ~500 MW being consented

- What instruments are appropriate to hedge BESS systems?

Recent developments in NZ hedge markets

- require market making for standardised super-peak contracts
- extend market making requirements, baseload curve to 5 years

From: “Strengthening price discovery in the forward electricity markets”

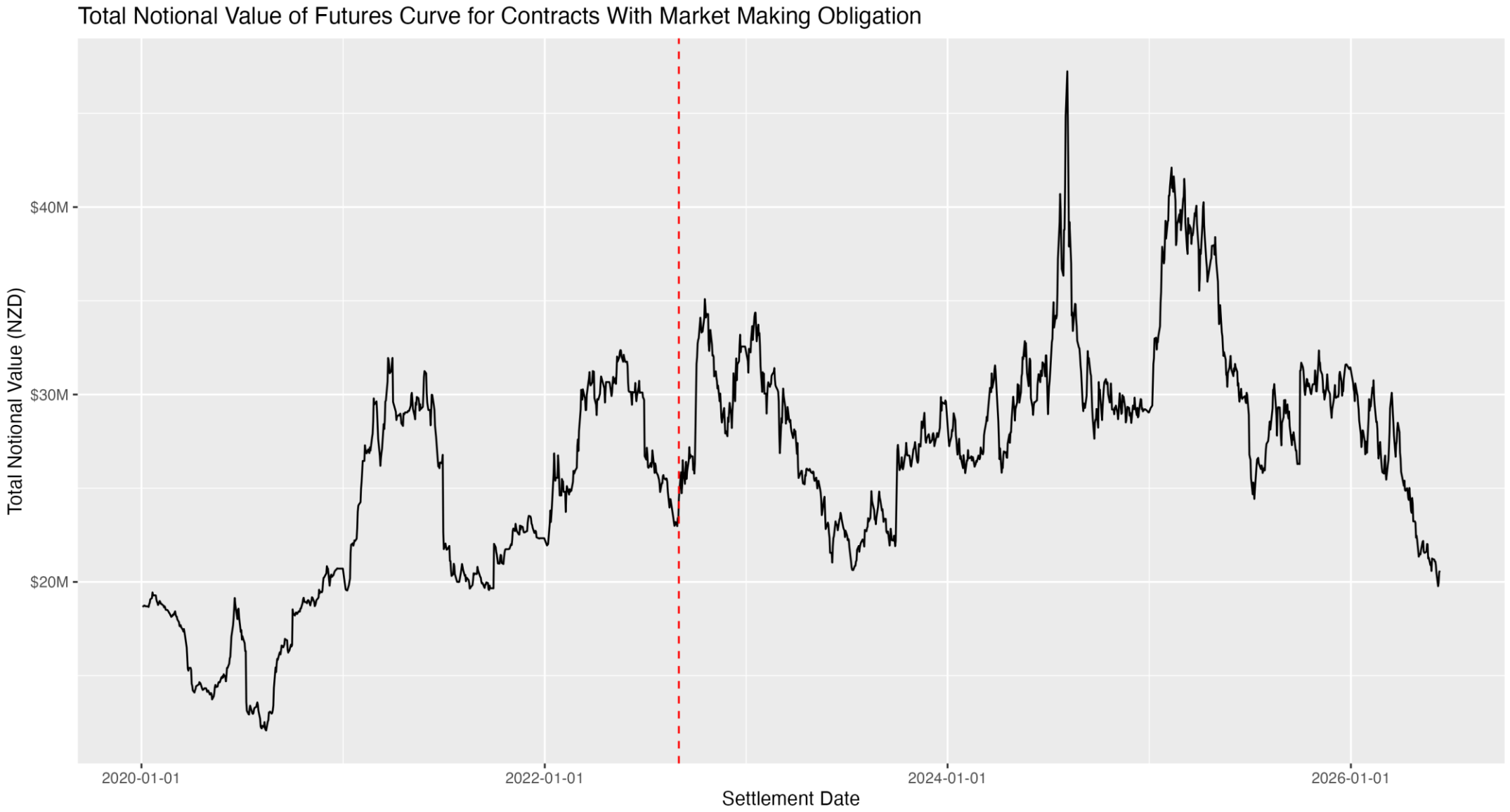
NZ Hedge Market Arrangements

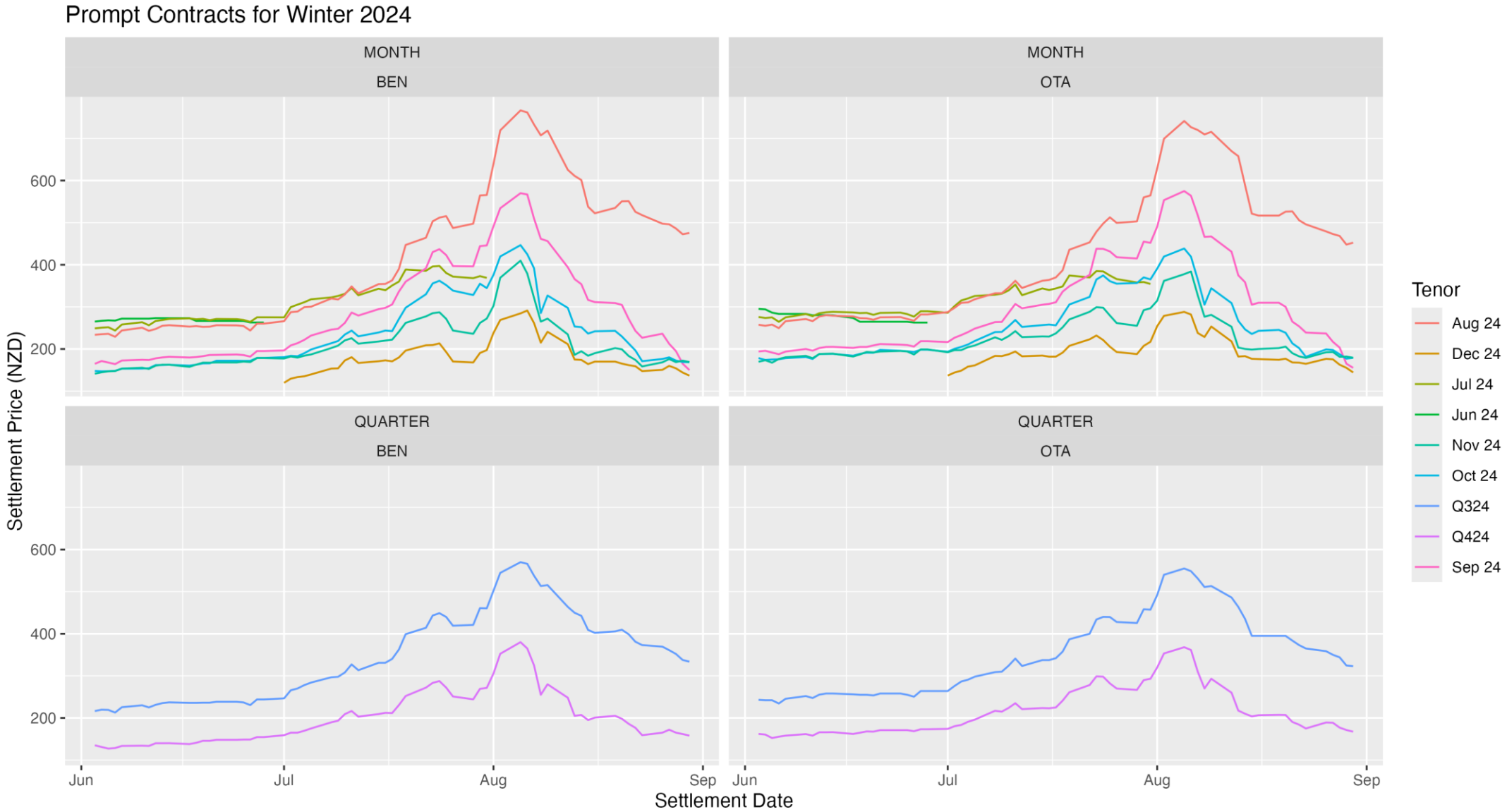
Dimension	Requirements
Products	ASX Monthly + Quarterly baseload contracts, Otahuhu and Benmore
Time Period	25 minutes for each 30 minute window, 15:30 – 16:00 business days
Volume	Total 24 lots (2.4 MW) per contract
Spread	Max(3% or $2)
Refresh	Initial volume of 12..12. Refresh when fully traded
Exemptions	5 exemptions in 20 day rolling window of business days

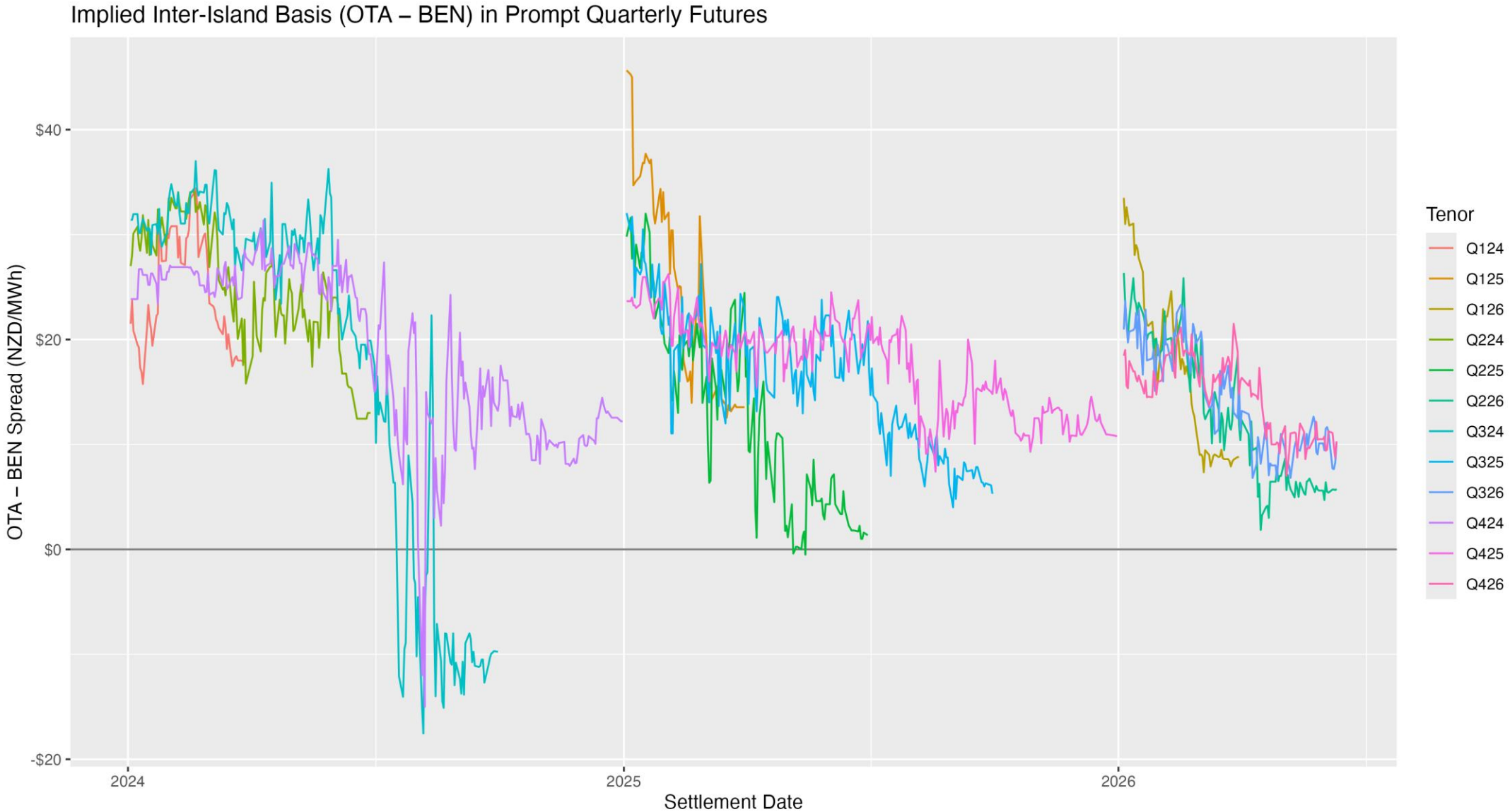
- Subpart 5B of Part 13 of the Electricity Industry Participation Code 2010

tenor	curve_part	season	contract_code_OTA	contract_code_BEN	hour_count_OTA	hour_count_BEN
str	str	str	str	str	i64	i64
Jun 26	FRONT	WINTER	ED2606	EH2606	720	720
Jul 26	FRONT	WINTER	ED2607	EH2607	744	744
Aug 26	FRONT	WINTER	ED2608	EH2608	744	744
Sep 26	FRONT	WINTER	ED2609	EH2609	720	720
Oct 26	FRONT	SUMMER	ED2610	EH2610	744	744
Nov 26	FRONT	SUMMER	ED2611	EH2611	720	720
Q226	FRONT	WINTER	EA2606	EE2606	2184	2184
Q326	FRONT	WINTER	EA2609	EE2609	2208	2208
Q426	FRONT	SUMMER	EA2612	EE2612	2208	2208
Q127	BACK	SUMMER	EA2703	EE2703	2160	2160
Q227	BACK	WINTER	EA2706	EE2706	2184	2184
Q327	BACK	WINTER	EA2709	EE2709	2208	2208
Q427	BACK	SUMMER	EA2712	EE2712	2208	2208
Q128	BACK	SUMMER	EA2803	EE2803	2184	2184
Q228	BACK	WINTER	EA2806	EE2806	2184	2184
Q328	BACK	WINTER	EA2809	EE2809	2208	2208
Q428	BACK	SUMMER	EA2812	EE2812	2208	2208
Q129	BACK	SUMMER	EA2903	EE2903	2160	2160
Q229	BACK	WINTER	EA2906	EE2906	2184	2184
Q329	BACK	WINTER	EA2909	EE2909	2208	2208
Q429	BACK	SUMMER	EA2912	EE2912	2208	2208

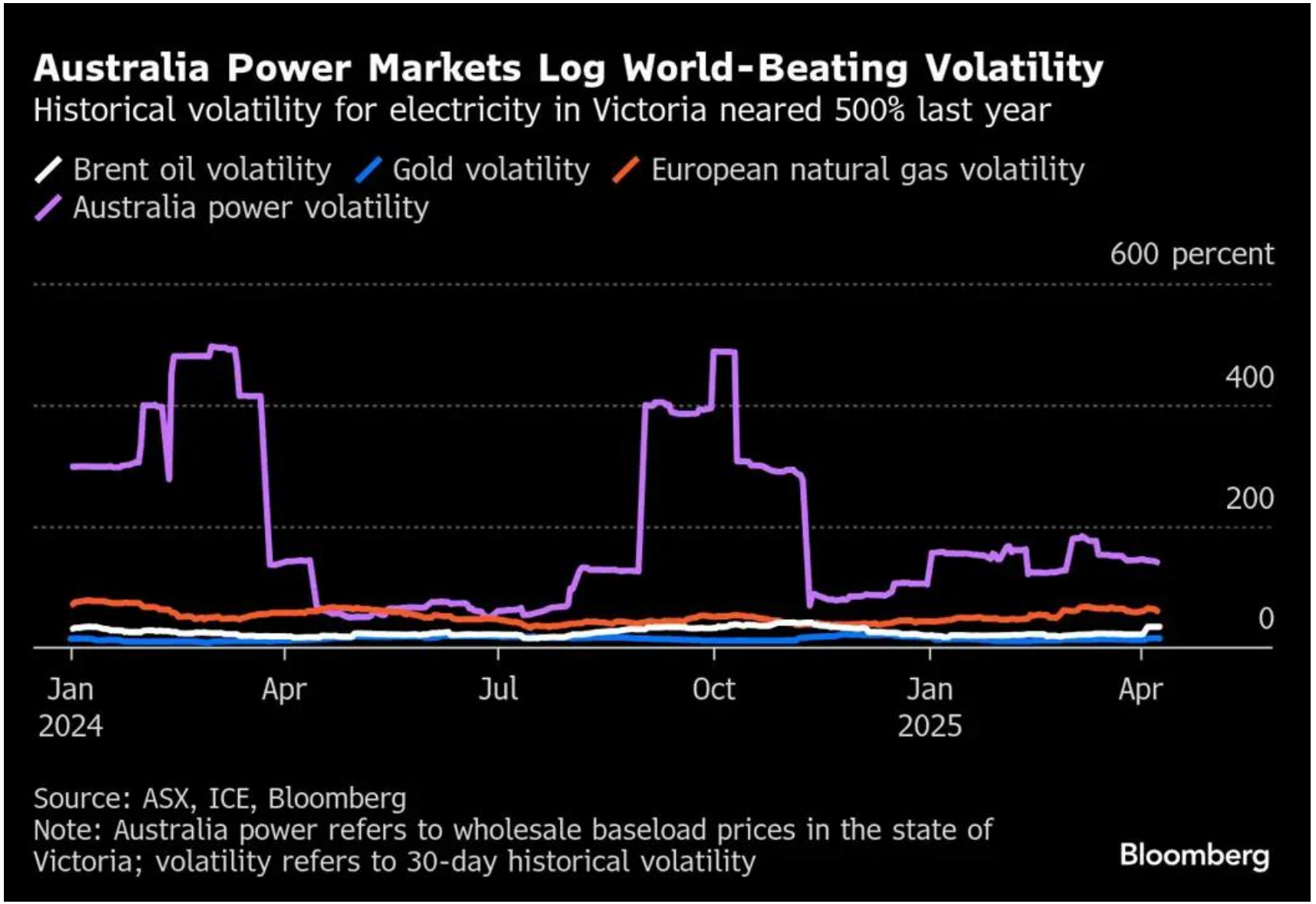
tenor	curve_part	contract_code_OTA	settlement_price_OTA	contract_code_BEN	settlement_price_BEN
str	str	str	f64	str	f64
Jun 26	FRONT	ED2606	84.9	EH2606	77.2
Jul 26	FRONT	ED2607	122.95	EH2607	112.7
Aug 26	FRONT	ED2608	131.25	EH2608	119.75
Sep 26	FRONT	ED2609	101.35	EH2609	92.8
Oct 26	FRONT	ED2610	84.95	EH2610	77
Nov 26	FRONT	ED2611	76.8	EH2611	64.2
Q226	FRONT	EA2606	89.2	EE2606	83.6
Q326	FRONT	EA2609	118.7	EE2609	108.6
Q426	FRONT	EA2612	77.5	EE2612	67
Q127	BACK	EA2703	132.15	EE2703	112.35
Q227	BACK	EA2706	184	EE2706	167.1
Q327	BACK	EA2709	181.75	EE2709	167.5
Q427	BACK	EA2712	73.1	EE2712	63.5
Q128	BACK	EA2803	116.5	EE2803	97.25
Q228	BACK	EA2806	178	EE2806	162.05
Q328	BACK	EA2809	174.85	EE2809	163.65
Q428	BACK	EA2812	71.85	EE2812	62.25
Q129	BACK	EA2903	111.5	EE2903	91.25
Q229	BACK	EA2906	172.5	EE2906	155.55
Q329	BACK	EA2909	174.5	EE2909	154.95
Q429	BACK	EA2912	70	EE2912	60.85


Total Notional Value of Futures Curve for Contracts With Market Making Obligation
Total Notional Value (NZD)
$40M
$30M
$20M
2020-01-01
2022-01-01
2024-01-01
2026-01-01
Settlement Date


Prompt Contracts for Winter 2024
MONTH
BEN
MONTH
OTA
QUARTER
BEN
QUARTER
OTA
Settlement Price (NZD)
600
400
200
Jun
Jul
Aug
Sep
Settlement Date
Tenor
Aug 24
Dec 24
Jul 24
Jun 24
Nov 24
Oct 24
Q324
Q424
Sep 24


Implied Inter-Island Basis (OTA – BEN) in Prompt Quarterly Futures
OTA – BEN Spread (NZD/MWh)
$40
$20
$0
-$20
2024
2025
2026
Settlement Date
Tenor
Q124
Q125
Q126
Q224
Q225
Q226
Q324
Q325
Q326
Q424
Q425
Q426


Volatility Term Structure of NZ Futures
Annualised daily settlement-price volatility by months to expiry
MONTH
FRONT
QUARTER
BACK
QUARTER
FRONT
125%
100%
75%
50%
25%
Annualised Volatility
5
4
3
2
1
0
30
20
10
15
10
5
0
Months to Expiry
Node
BEN
OTA


Australia Power Markets Log World-Beating Volatility
Historical volatility for electricity in Victoria neared 500% last year
Brent oil volatility
Gold volatility
European natural gas volatility
Australia power volatility
600 percent
400
200
0
Jan 2024
Apr
Jul
Oct
Jan 2025
Apr
Source: ASX, ICE, Bloomberg
Note: Australia power refers to wholesale baseload prices in the state of Victoria; volatility refers to 30-day historical volatility
Bloomberg

Cost of Market Making

- Generally, not public information
- Contact Energy 2025 response to EA's MM Review paper:
  - $-30.3m [2023]
  - $-6.5m [2024]
  - $-15.8m [2025]
- In 2022 the EA levy increased $14.4m to fund the commercial market making scheme
- Suggests industry wide cost is approximately $70-80m pa.
- Cost will increase in 2027 with longer futures curve

Scratch Trading Analysis (1/2)

- What is a “scratch trade”
- Some financial participants raised concern over “Market Maker” vs “Market Taker” behaviour
- The EA commissioned the Lantau Group to investigate
- Limitations they acknowledge:
  - No cross-product scratch detection
  - No order-book reconstruction, spread and depth based on session best
  - Conservative aggressive classification timestamp matching!

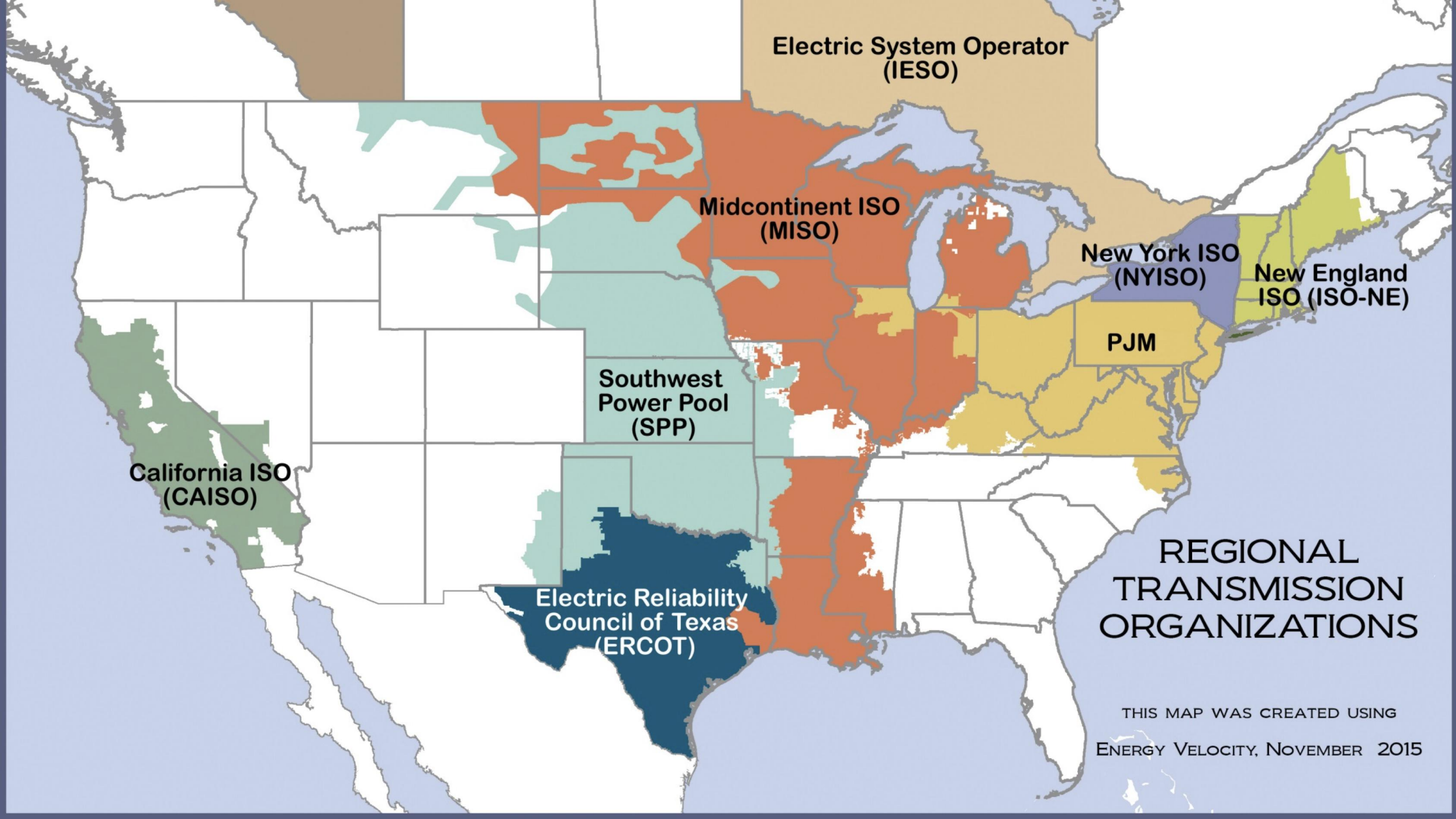
Scratch Trading Analysis (2/2)

- Limitations they do not mention:
  - Each market maker behavior is considered in isolation
  - Cascading events can remove liquidity over multiple contracts and levels with no economic intent
  - Exploitative “grid trading” is almost certainly happening

- My opinion: the EA should investigate how many MM trades are scratched into the participant who initially hit their resting order.

Financial Transmission Rights

- Instrument to hedge location-based price risk
- Auctioned every month
- Settlement is Auction Price – Revenue for Contract period
- Hedge Types:
  - Option SUM(MAX(0, Sink – Source))
  - Obligation SUM(Sink – Source)
- Time of Use:
  - 24-Hours (New Zealand)
  - Off-Peak, WeekDay Peak, WeekEnd Peak (ERCOT) more coming…


Electric System Operator (IESO)
Midcontinent ISO (MISO)
New York ISO (NYISO)
New England ISO (ISO-NE)
PJM
Southwest Power Pool (SPP)
California ISO (CAISO)
Electric Reliability Council of Texas (ERCOT)
REGIONAL TRANSMISSION ORGANIZATIONS
THIS MAP WAS CREATED USING
ENERGY VELOCITY, NOVEMBER 2015

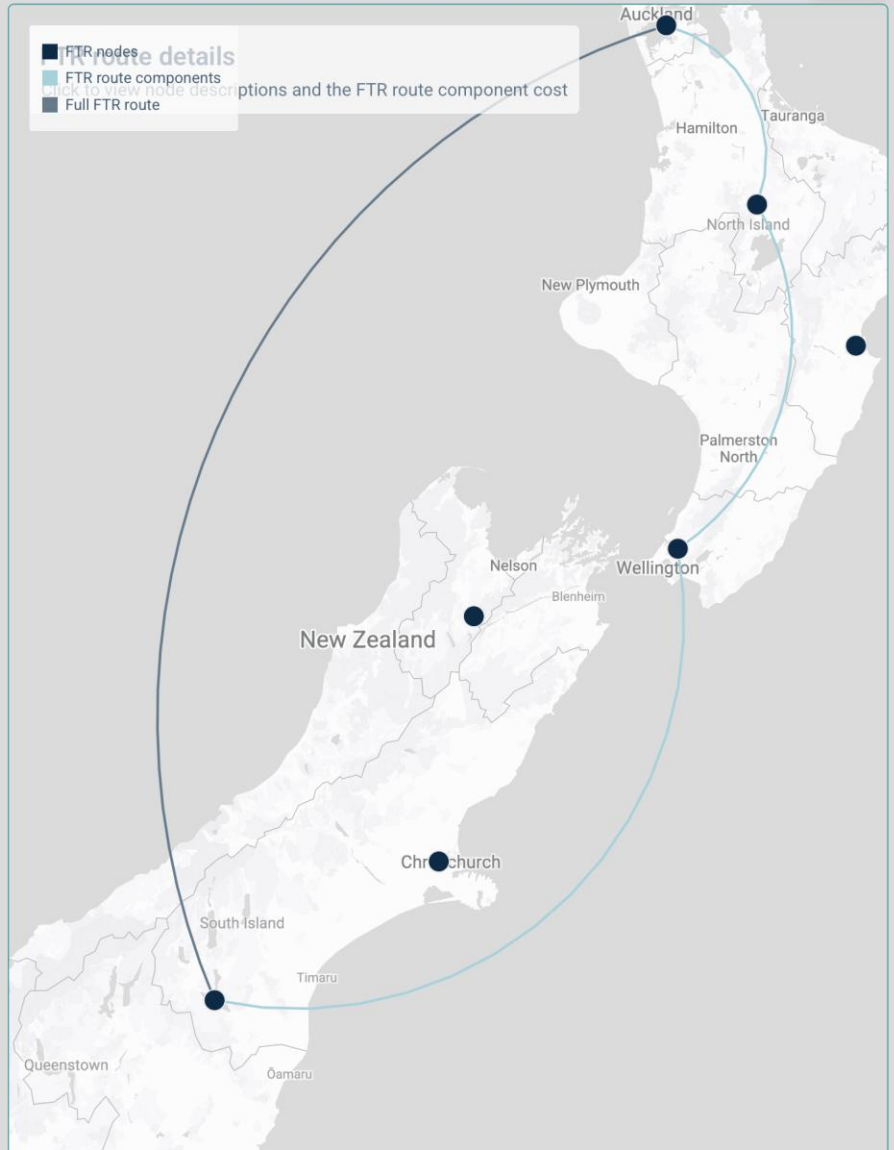
Market	Peak Load (GW)	# of Price Points	Time of Use
ERCOT	91	~ 1,000	OffPeak, PeakWD, PeakWE, (more coming)
PJM	168	2,000 +	24-Hour, OnPeak, OffPeak
MISO	127	2,500 +	OnPeak, OffPeak
SPP	58	1,000 +	OnPeak, OffPeak
NYISO	34	~ 300	24-Hour
ISO-NE	28	1,000 +	OnPeak, OffPeak
New Zealand	7	8	24-Hour

Source node

Invercargill | **Benmore AC** | Islington | Kikiwa | Haywards AC | Redclyffe | Whakamaru

Sink node

Invercargill | Islington | Kikiwa | Haywards AC | Redclyffe | Whakamaru | **Ōtāhuhu**



Auction type

Primary | Variation

Auction month

Aug 26

Contract start month

Aug 28

Benmore AC to Ōtāhuhu FTR $/MWh

Aug 2026 primary auction — Aug 2028 contract

$14.01

FTR route breakdown	$/MWh
Benmore AC to Ōtāhuhu	$14.01
Benmore AC to Haywards AC	$5.69
Haywards AC to Whakamaru	-$0.95
Whakamaru to Ōtāhuhu	$9.28

Comparison to ERCOT instruments

- "Granular Product Type for CRR Time of Use”
- Split hour blocks into solar day/non-solar day
- HE 9-18, non-solar peak hours: HE 7-8, HE 19-22
- Allows participants hedge more efficiently with Obligations

- ICE product: TB2, TB4, 1 MW cash settled, average of 2 highest hours – average of 2 lowest hours.
  - DA, RT, monthly, daily
  - Similar to MDAGs charge / discharge product?

Conclusions

- Should be proud of your market design, one of the first!
- Evolving grid changes the risks participants face
- Innovation in pricing electricity risk in time (futures curve) and space (congestion markets) can help support more efficient outcomes