Risk and efficiency in hydro-dominated electricity markets

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National Science Challenges
SCIENCE FOR TECHNOLOGICAL INNOVATION

Te Pūnaha Matatini
Data ▪ Knowledge ▪ Insight

MARSDEN FUND
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Motivation

- New Zealand has an energy-only wholesale market that has been operating unchanged since 1996. There is no capacity market or day-ahead market, and regulation of the New Zealand wholesale market is light-handed.
- We want wholesale electricity markets to be efficient.
  - allocate resources efficiently for benefit of consumers;
  - provide efficient investment signals
- The EMBER project seeks a counterfactual model that one can compare with actual market outcomes in backcasts.

Previous related work

- Owen Auger, Masters thesis, 2007.
- Wolak Report, May, 2009.
- Philpott, Zakeri, Guan, Khazaei, Utilities Policy, 2010.
- Philpott and Guan, Models for estimating the performance of electricity markets with hydro-electric reservoir storage, 2013 (http://www.epoc.org.nz/papers/EMBERPaperv32b.pdf)
- Telfar, G. Hindcasting market performance with SPECTRA, EMarket and LPcon (http://www.epoc.org.nz/workshops/ww2014/Telfar.pptx)
- Nicholas Porter, Intra-day uncertainty and efficiency in electricity markets, ME thesis, 2014.
- Watson, A. Hindcasting: a look in the rear-view mirror (http://www.epoc.org.nz/workshops/ww2017/EPOCWatson2017.pdf).
- EMBER 2.0: 2017- 2018

Risk and competition

- Perfectly competitive markets can be inefficient if trading opportunities are missing.
- Example: Meridian-Genesis swaption contract enables more efficient operation of Huntly and Waitaki by decreasing risk for both parties.
- Theorem (PFW, 2016; FP, 2018): If markets for risk (using dynamic coherent risk measures) are complete then a perfectly competitive (risk-averse) equilibrium corresponds to a risk-averse social optimum using a social risk measure.
- Computing and comparing risk-averse social optima can provide a benchmark for competition under risk.
- Electricity Market Benchmarking Exploring Risk

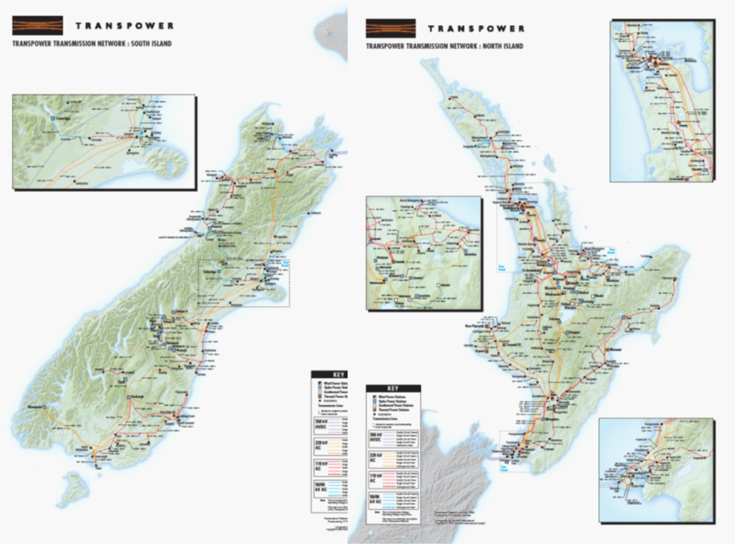
Summary

Summary

Modelling the New Zealand electricity system

- NZ has a nodal market with 250 nodes.
- Wholesale market is dispatched every 30 minutes using software called SPD. This yields generation levels for every generator and 250 prices every half hour.
- SPD inputs (offers of energy that are made by generators, network constraints and demand) are made public two weeks after the day of dispatch.
- NZ electricity regulator has developed a GAMS/CPLEX model that replicates SPD output. It is called vSPD.
- So one can run counterfactual tests on market outcomes from two weeks ago.

The SPD network



Network diagram of New Zealand transmission grid.

The historical market outcome

- Historical prices and dispatch are recorded in Electricity Authority data sets, but we require transmission flows.
- Run vSPD with historical offers and demand for every half hour from January 1, 2005 to December 31, 2016 and record all outcomes.
- Along with historical daily inflows and reservoir levels this forms the historical market outcome.
- Historical outcome can disable spinning reserve and ignore reserve offers and constraints.
- Historical outcome can include spinning reserve using historical reserve offers and dispatch.

Summary

A daily counterfactual
[N. Porter Masters thesis, 2014]

- For each day, compute the historical stored water used by each river system.
- Solve a daily social planning model HydrovSPD that uses the same amount of water in each river system and thermal generation to meet demand minimizing fuel plus variable OM costs (SRMC).
- HydrovSPD can ignore reserve (as in Porter thesis) or include reserve (offered at zero cost).

A daily counterfactual

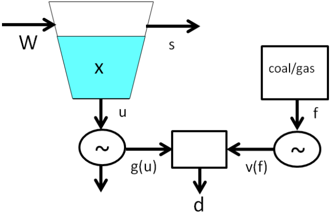
- Clairvoyant HydrovSPD is a single optimization of 48 copies of vSPD linked by hydro transfers between stations, and assuming perfect foresight of inflows and demand over the day.
- Rolling-horizon HydrovSPD solves HydrovSPD in a rolling horizon model assuming deterministic inflows but forecasts of future demand that are updated at each iteration.
- Price-taking vSPD simulates the market where each agent optimizes their own river chain over next 48 periods as a price taker. In each iteration in a rolling-horizon model:
  - each generator prepares price-taking offers for the next 48 periods;
  - future demand forecasts are updated;
  - vSPD is solved for 48 periods using offers and demand forecast;
  - forecast spot prices for next 48 hours are published;

Summary of results from Nick Porter thesis (no reserve)

- Clairvoyant HydrovSPD has on average a 10 % lower cost ($40M) than historical market cost.
- Rolling horizon HydrovSPD cost is close to Clairvoyant HydrovSPD cost.
- Price-taking vSPD cost is just below historical market cost.
- Takeaways
  - Uncertainty in demand does not increase the cost by much if offers are SRMC.
  - Lack of generator coordination is costly when price forecasts are inaccurate.
  - Short run inefficiency (in sample days tested) attributed to coordination loss rather than strategic offers.
  - Conjecture that a day-ahead market would improve efficiency.

Summary

What should reservoir targets be?

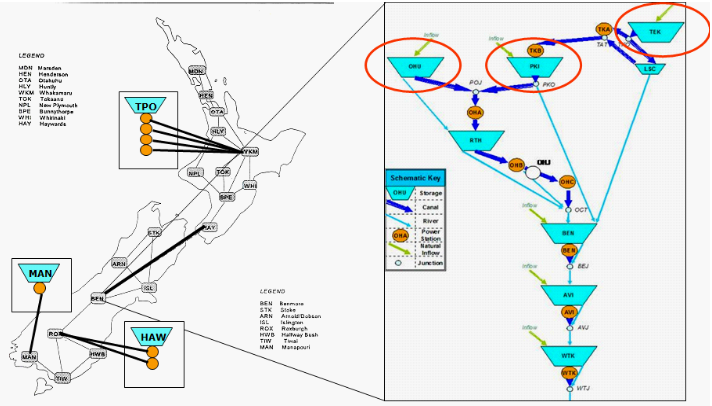


- Can we improve efficiency with better daily targets for reservoir levels?
- Hydrogenerators in the market assign a market value to water.
- Counterfactual model will assign a social value to water.

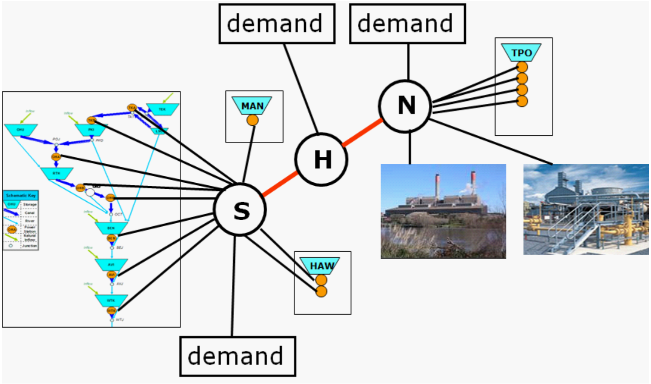
Social water value

- Minimize risk-adjusted annual social cost of fuel burned and shortages computed using stochastic dynamic programming (i.e. DOASA, our implementation of SDDP for the New Zealand electricity system).
- DOASA models risk aversion using a coherent dynamic risk measure (P., deM., F., 2013). Risk averse generators treat low inflows with higher probability than estimates from historical data.
- DOASA policy defines a risk-adjusted marginal water value measured in $/m^3 This is defined for each possible reservoir level, and is the risk-adjusted opportunity cost of releasing one unit of water.
- The risk-adjusted marginal water value can be used to set a target for HydrovSPD.

Large hydro reservoirs modelled



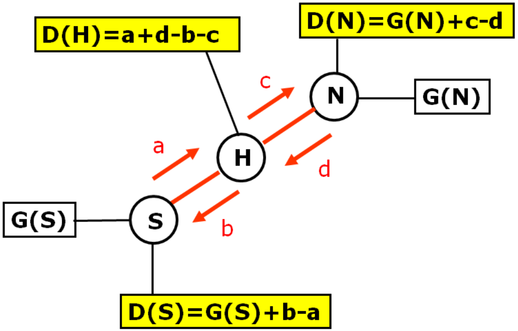
The three-node SDDP network with hydro



What is demand in this three-node system?

- We seek a competitive dispatch in our three-node system.
- Restrict optimization to large generators: hydro (reservoir and run-of-river), geothermal and thermal plant.
- All others generate at historical levels, so subtract them from demand.
- Aggregating demand at three nodes is problematic because of intra-regional losses.
- Let national demand equal total generation from large generators and split into three according to historical transmission flows beween regions.

Regional demand equals historical generation



We compute regional demand in each trading period to match historical generation of regional generators adjusted for historical imports and exports (extracted from transmission flows in vSPD).

Caveats

- Future demand for each load block in future weeks is assumed to be known.
  - Actual demand is temperature dependent so has a random element.
  - Some small generation (wind) is random, but we assume its weekly contribution is known in advance.
- Historical demand might have been reduced because of high prices.
  - We should inflate observed demand by shed load (if we can estimate it).
  - We have not done this in this study. Prices computed in counterfactual might be biased low.

Computing a counterfactual for a calendar year

- Obtain historical reservoir levels for January 1, previous years inflow data and system data for year.
- For fortnight $f = 1$ to 26
  - Solve three-node DOASA starting at beginning of fortnight f to give an optimal policy
  - For each day d in fortnight f
    - Solve a 250 node full HydrovSPD model with no water targets but paying marginal value from DOASA cuts for all stored water used over the day;
    - Output quantities of interest for each period (prices, dispatch, reservoir levels);
    - Record reservoir levels for the start of the next day;
    - Go to next day.
  - Record reservoir levels for the start of the next fortnight;
  - Go to next fortnight.

Cost data

- Coal costs assumed to be at \$4/GJ (MBIE)
- Gas/diesel prices from MBIE website http://www.mbie.govt.nz/info-services/sectors-industries/energy/energy-data-modelling/statistics/prices
- VOLL= \$10000/MWh in 2015 dollars
  - Peaker at 5 hours per year over 20 years earns \$1M = approx capital cost of 1MW capacity (PB 2008 EC report).
- Carbon costs from NZU prices and emission quantities at http://www.ea.govt.nz/about-us/corporate-projects/uts/consultations/#c9239
- Operating and maintenance costs ("Thermal Power Station Advice - Fixed & Variable O&M Costs" prepared by PB New Zealand in September 2009.)

Hydro data

- Inflows and lake levels from Electricity Authority EMI site
- Tekapo storage must be above minimum level.
- Generation capacities
  - Websites of companies that own the stations
  - Generation fleet spreadsheet in 20151030_Existing_generating_plant.xls on EMI website
- Constant water conversion factors for each hydro station estimated from the result of the INTER model in the EMBER 1.0 Project.

Summary

Assumptions for historical outcome

- Use historical demand in full vSPD network
- Use historical offers in full vSPD network
- All historical constraints (e.g. security constraints) used
- For reserve, either
  - (hNR): disable reserve constraints in vSPD.
  - (hMR): Include historical market reserve requirements and optimize reserve using historical offers.

Simulation assumptions for HydrovSPD given a policy

- Use historical demand in full vSPD network
- Fix Manapouri generation and reservoir levels at historical values. Other large reservoirs have (end-of-day) water values.
- Hydroelectric plant offers same quantities at $0/MWh.
- Thermal plant offers historical quantities at SRMC.
- For reserve, either
  - (cNR): disable reserve constraints in HydrovSPD
  - (cHR): Set reserve requirement to be HVDC risk and optimize reserve offered at 0

Different levels of uncertainty for policy

- (WC): fix all hydro generation at historical and optimize thermal at SRMC (the Wolak counterfactual)
- (MF): fix only Manapouri generation at historical and compute water values for other large hydro.
- (MD): Estimate decision rule constraining Manapouri generation and compute water values for all large hydro.

Different levels of risk for policy

- (N): policy assumes social planner is risk-neutral (minimizes expected social disbenefit)
- (R): policy assumes social planner is risk-averse (assigns 0.525 probability to worst-case inflow, 0.025 to other 19)

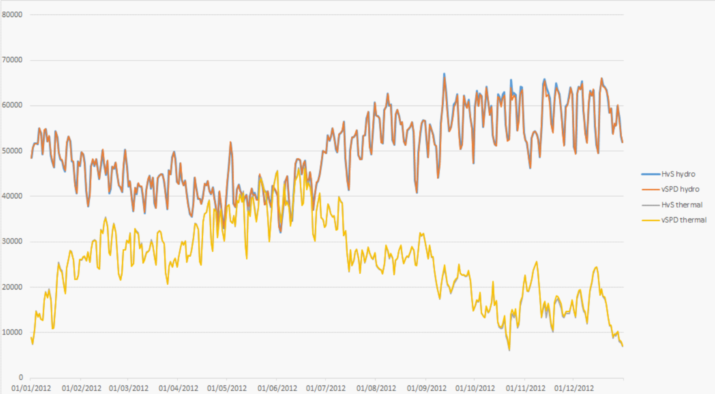
Run	Model	Reserve	Risk	HvSPD	Market
1	All hydro fixed	none	n.a.	cNR	hNR
2	Manapouri fixed	none	N	cNR	hNR
3	Manapouri DR	none	N	cNR	hNR
4	Manapouri DR	HVDC	N	cHR	hMR
5	Manapouri DR	HVDC	R	cHR	hMR

Summary

What are the key results?

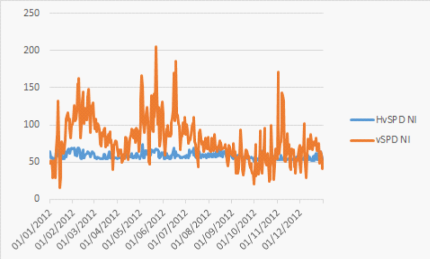
- We look at two performance measures of counterfactual versus market.
- Productive efficiency
  - We compute the variable cost incurred by the system over 2012 for counterfactual and market.
  - When the counterfactual system becomes closer to the market system, the gains in productive efficiency decrease.
- Wealth transfers from consumers to generators
  - We compare spot prices in counterfactual and market.
  - We compare Ricardian rents in counterfactual and market.
  - When the counterfactual model includes more uncertainty, spot prices and rents increase.

Daily generation with hydro fixed

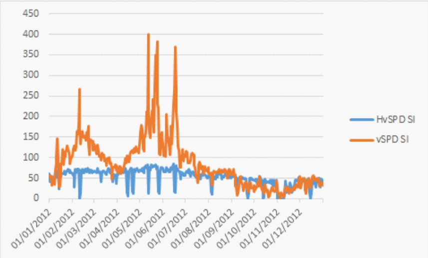


Daily generation over 2012

Price differences with hydro generation fixed



Daily average prices in the North Island



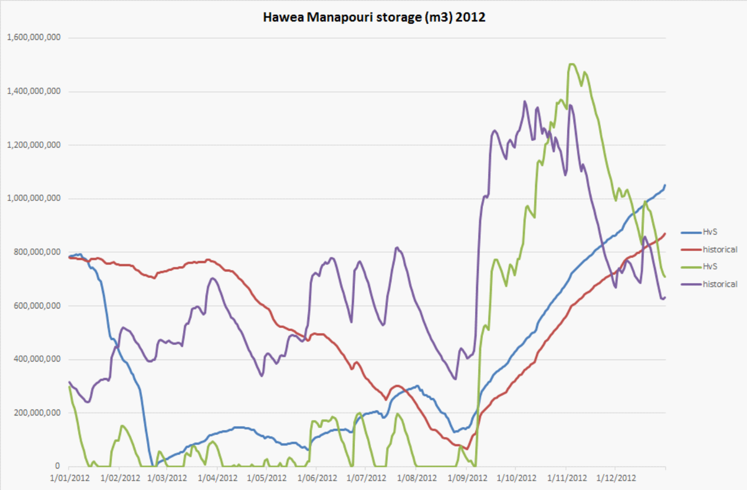
Daily average prices in the South Island

Outcomes with hydro generation fixed

($M)	Thermal cost	End storage value	Hydro (GWh)	Thermal (GWh)	NI price	SI price	Revenue	Rent
Hydro vSPD	510	0	18,328	9,460	58	52	1,506	996
vSPD	517	0	18,328	9,475	78	85	2,288	1,771
Difference	-7	0	1	-15	-20	-33	-782	-775

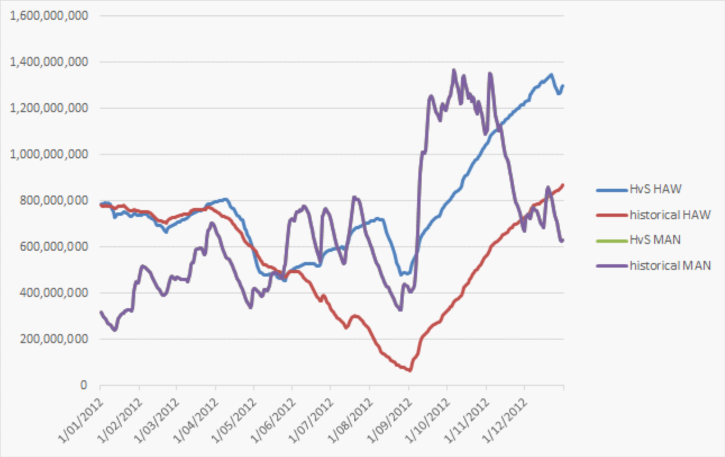
Costs, rents and production comparing counterfactual and market.

Hawea and Manapouri storage when hydro optimized



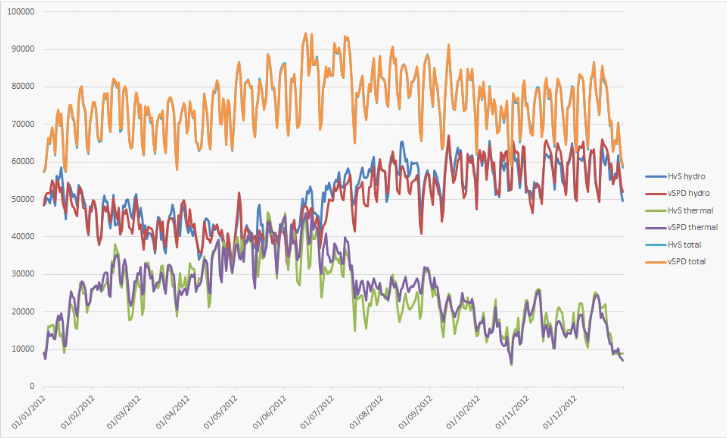
With all storage unfixed, Manapouri is drawn down to zero violating environmental constraints.

Fix Manapouri generation and spill to historical levels



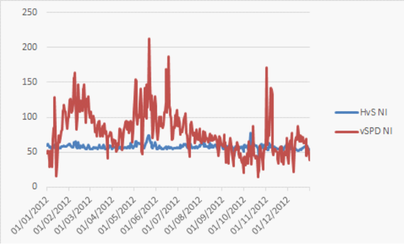
Manapouri storage now tracks historical storage.

Fix Manapouri generation and spill to historical levels



Manapouri generation and spill equal to historical levels. Less uncertainty affects other hydro generation by lowering water values.

Fix Manapouri generation and spill to historical levels



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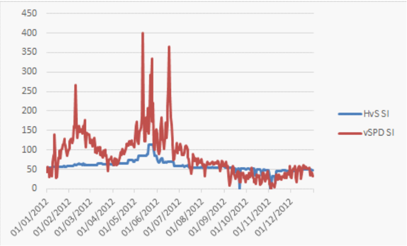
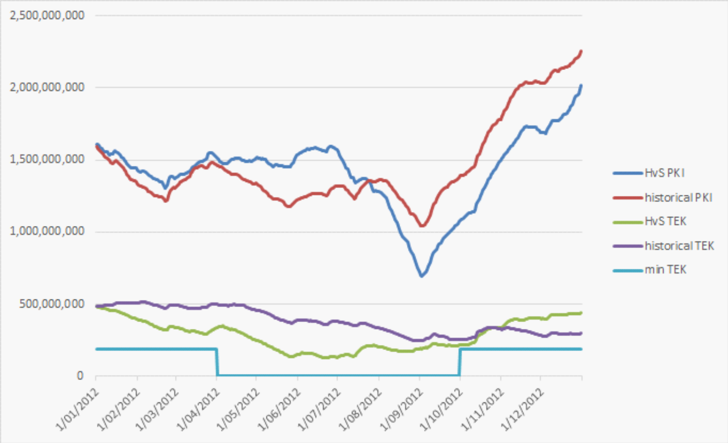


Daily average prices in the South Island

Fix Manapouri generation and spill to historical levels



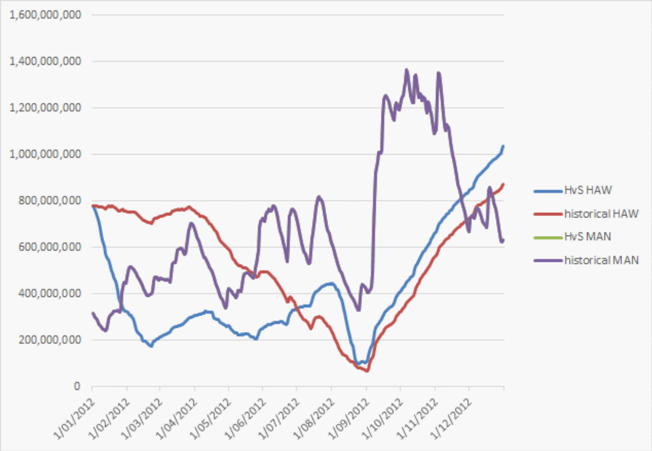
Pukaki and Tekapo lake levels compared with historical. Water is retained.

Outcomes

($M)	Thermal cost	End storage value	Hydro (GWh)	Thermal (GWh)	NI price	SI price	Revenue	Rent
Hydro vSPD	492	-560	18,588	9,161	58	59	1,584	1,092
vSPD	517	-574	18,328	9,475	78	85	2,288	1,771
Difference	-25	14	260	-313	-21	-26	-704	-679

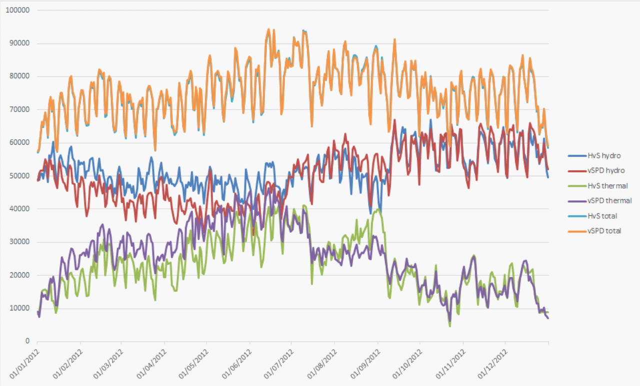
Costs, rents and production comparing counterfactual and market. $39M productive efficiency savings.

Manapouri decision rule



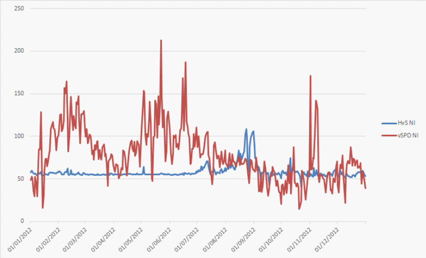
Manapouri and Hawea lake levels compared with historical.

Manapouri decision rule

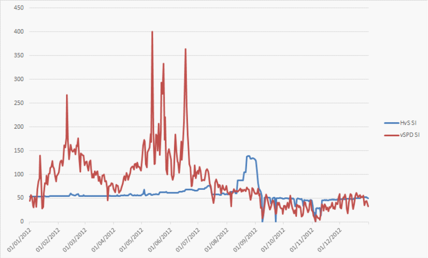


Manapouri generation $\leq$ min{a*inflow,capacity}

Manapouri decision rule



Daily average prices in the North Island



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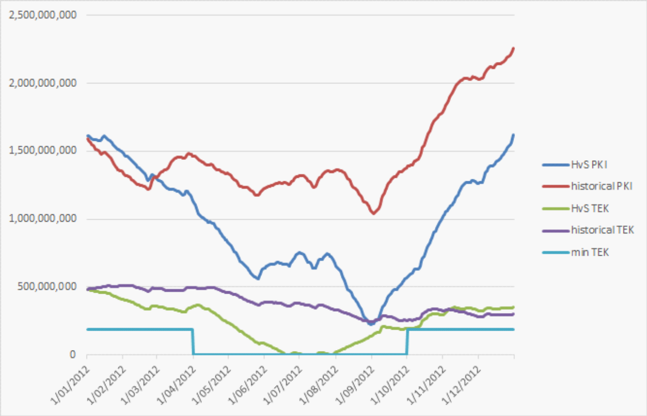


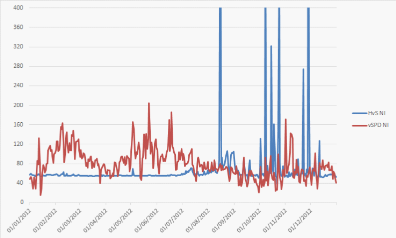
Pukaki and Tekapo lake levels compared with historical.

Outcomes

($M)	Thermal cost	End storage value	Hydro (GWh)	Thermal (GWh)	NI price	SI price	Revenue	Rent
Hydro vSPD	460	-331	19,149	8,553	58	58	1,585	1,125
vSPD	517	-318	18,328	9,475	78	85	2,288	1,771
Difference	-57	-14	822	-922	-20	-27	-703	-646

Costs, rents and production comparing counterfactual and market. $43M productive efficiency savings.

Manapouri decision rule with HVDC reserve



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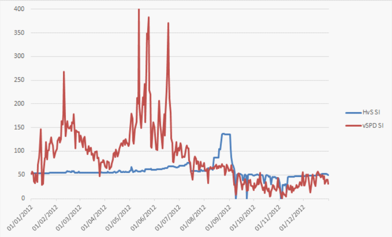
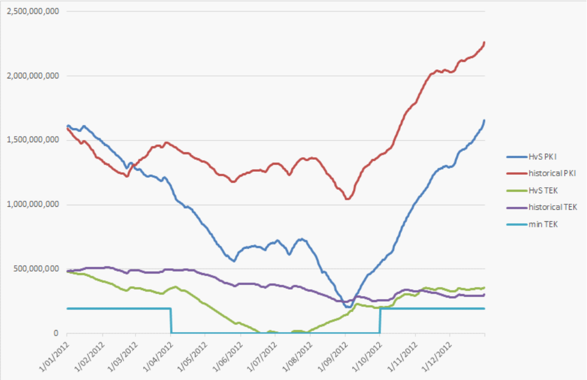


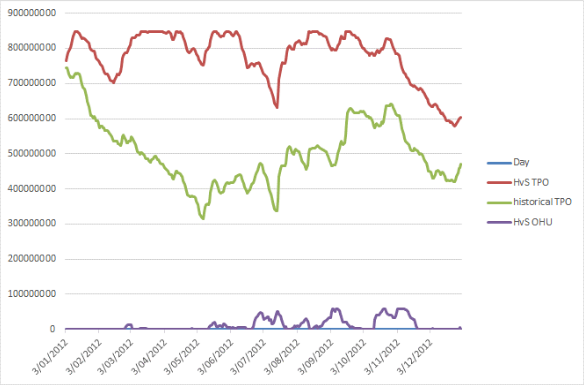
Daily average prices in the South Island

Manapouri decision rule with HVDC reserve



Pukaki and Tekapo lake levels compared with historical.

Manapouri decision rule with HVDC reserve



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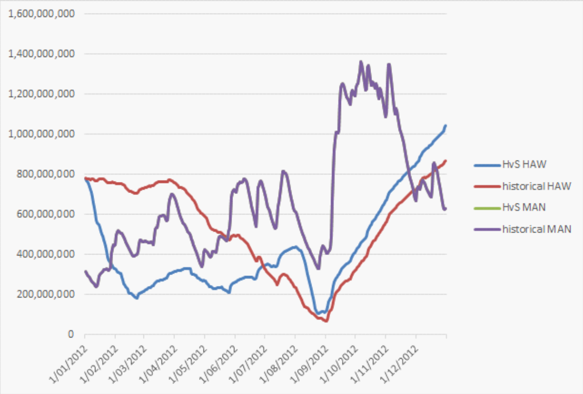


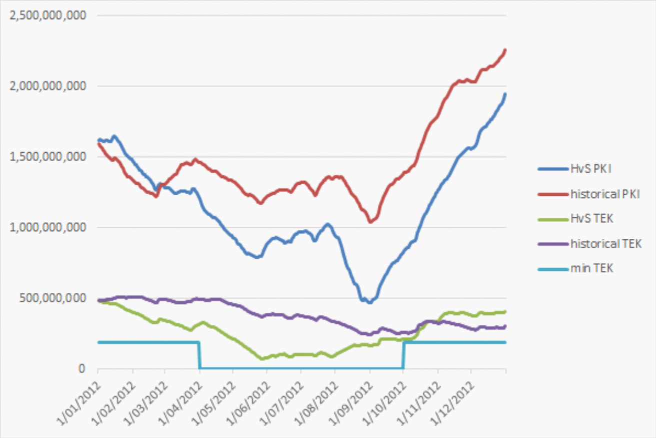
Manapouri and Hawea lake levels compared with historical.

Outcomes

($M)	Thermal cost	End storage value	Hydro (GWh)	Thermal (GWh)	NI price	SI price	Revenue	Rent
Hydro vSPD	463	-330	19,108	8,583	68	58	1,737	1,274
vSPD	517	-318	18,309	9,472	80	86	2,311	1,794
Difference	-54	-13	799	-889	-11	-29	-574	-520

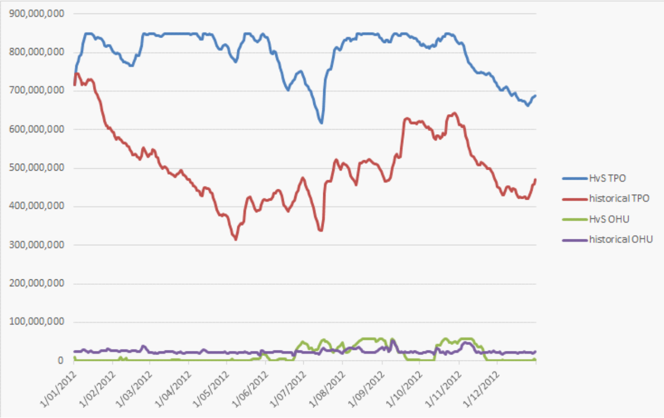
Costs, rents and production comparing counterfactual and market. $41M productive efficiency savings.

Risk-averse Manapouri DR with HVDC reserve



Pukaki and Tekapo lake levels compared with historical.

Risk-averse Manapouri DR with HVDC reserve

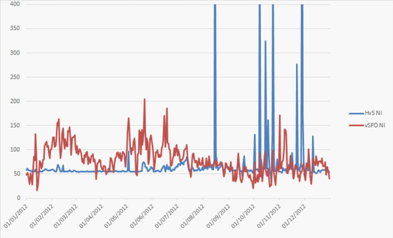


North Island lake levels compared with historical.

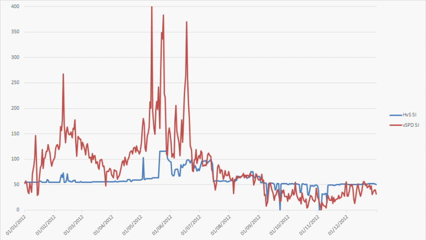
Risk-averse Manapouri DR with HVDC reserve

Manapouri and Hawea lake levels compared with historical.

Risk-averse Manapouri DR with HVDC reserve



Daily average prices in the North Island



Daily average prices in the South Island

Outcomes

($M)	Thermal cost	End storage value	Hydro (GWh)	Thermal (GWh)	NI price	SI price	Revenue	Rent
Hydro vSPD	488	-432	18,681	9,048	68	60	1,774	1,285
vSPD	517	-438	18,309	9,472	80	86	2,311	1,794
Difference	-29	7	372	-424	-11	-27	-538	-509

Costs, rents and production comparing counterfactual and market. $36M productive efficiency savings.

Conclusions

- Daily market coordination is not as efficient as it could be. Day-ahead market might alleviate this.
- Productive efficiency gains insensitive to long-term uncertainty model.
- Water values sensitive to long-term uncertainty.
- Market water values are higher than perfectly competitive values.
- Market rents are higher than perfectly competitive rents.
- We study efficiency, not ownership; our benchmarks are consistent with a competitive, complete wholesale market with privatized assets.

The End

THE END

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