EMBER 2.0 Online Companion

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Contents

1 Introduction

The EMBER 2.0 project (Electricity Market Benchmarking Exploring Risk) uses DOASA and Hydro vSPD as counterfactuals of the electricity market in New Zealand to benchmark the differences in thermal costs, reservoir storage, generation, prices and market rents between social planning and the market. DOASA implements the SDDP technique to schedule hydro-thermal power generation in a planning horizon of weekly stages and generate policies that are Benders cuts for reservoirs in a river-valley hydro network of four river chains. Hydro vSPD simulates energy dispatching and pricing in half-hourly trading periods accounting for the value of reservoir storage using Benders cuts on a day-by-day basis. DOASA and Hydro vSPD of difference versions are used in experiment. The results from Hydro vSPD are compared with the market results that consist of results generated using vSPD and historical reservoir storage. This online companion presents the model description, data and experiment in the project.

2 vSPD

The vSPD model is a duplicate of the market model, SPD. The model is available on the Electricity Market Information (EMI) website (EMI 2018c) and the input are gdx data files that are available on EMI 2018b. vSPD with no reserve and vSPD with HVDC risk and reserves are run to generate market results. vSPD of version 1.4 is used for 2005 to 2014. The parameter of DispatchableDemandGDXGDate in the vSPDSolve.gms file for vSPD of version 1.4 is changed from 41773 to 41778 (This change was informed by Tuong Nguyen in the Electricity Authority). vSPD of version 2.0.5 is used for 2015 to 2017. A national market for interruptible load reserve from October 20, 2016 is implemented in vSPD of version 3.0.3 but is ignored.

2.1 Setting and adaptation

vSPD with reserves is run by running a macro in a spreadsheet in the Program folder and the settings are presented in Table 1. vSPD with no reserve is run with the settings in the table but with the Include reserves parameter set to 0. vSPD with HVDC risk and reserves is run with the settings in the table and the following adaptations in vSPD.

- The parameter of IslandRiskAdjustmentFactor for HVDC risk is set to 1 and those for the other risks are set to zero.
- In the constraint of risk offset calculation for HVDC risk, the risk offset is the net free reserve and HVDC pole ramp up for DCCE and is only the net free reserve for DCECE. The net free reserve is minimised with a penalty cost of $1,000/MW in the objective function and bounded by zero and historical net free reserve. Thus the solution to it is the minimum net free reserve needed to meet reserve requirements.

Parameter	Value
Model	Standard vSPD
License model	1 (Developer)
Solver name	CPLEX
Vectorisation	1 (Yes)
Produce trade period reports	1 (Yes)
Use variable reserves	-1 (Auto)
Include reserves	1 (Yes)
Include AC losses	1 (Yes)
Include HVDC losses	1 (Yes)
Use Transpower loss segments	1 (Yes)
Resolve circular branch flows	1 (Yes)
Model AC branch limits	1 (Yes)
Model HVDC branch limits	1 (Yes)
LP time limit	36000 seconds
MIP time limit	36000 seconds
Operating mode	0 (Public)

Table 1: Settings for vSPD with reserves

- The generation of generators are fixed at historical level except those in large hydro power stations in three river chains (Waikato, Waitaki and Clutha) and main thermal power stations (Huntly, New Plymouth, Otahuhu B, Stratford and Whirinaki).
- The post-solve calculation of island reserve requirement takes into account only HVDC risk.

2.2 GDX data files

There is one gdx data file for each day from 2005 to 2017 except nine days.

- On August 5, 6 and 10, 2009, and December 19, 2016, there are two files that are identical except the data for case name and file name, and the first file is used.
- On July 21 and December 9, 2009, one file contains the data for the first some trading periods, the other file contains the data for the remaining trading periods of the day, and the violation costs in the parameters of i_CVPValues are different in the two files. Since the i_CVPValues in the second file does not change the solutions in vSPD run with the first file, the two files are merged with the i_CVPValues in the second file overwriting that in the first file.
- On July 21 and December 9 in 2009 and March 2, 3 and 17 in 2010, one file contains the data for the first some trading periods, the other file contains

the data for the remaining trading periods of the day, and there is no conflict in data. The two files are merged.

3 DOASA

The data used in DOASA is available in public sources, e.g., the EMI, the Ministry of Business Innovation and Economy (MBIE), and the data in the EMBER 1.0 project.

3.1 Planning horizon

Each year is divided into 52 weeks, and each week consists of seven days except that the last week consists of the remaining days in the year. The planning horizon consists of 52 weeks that can start from any week of a year.

3.2 Transmission network

The transmission network consists of three nodes that are upper North Island (NI), lower North Island (HAY) and South Island (SI), and four transmission lines that are NI-HAY, HAY-NI, HAY-SI and SI-HAY. The last two transmission lines are the HVDC lines. There is demand, or load, in each node. The hydro power stations in the Waikato River, main thermal power stations (Huntly main 1-4, e3p and peaker, New Plymouth 1-3, Otahuhu B, Stratford peakers, Taranaki Combined Cycle and Whirinaki), three small hydro power stations (Rangipo, Tokaanu and Waikaremoana) and two run-of-river hydro power stations (Mangahao and Matahina) are in NI. The hydro power stations in the Waitaki River, Clutha River and Manapouri River and two run-of-river hydro power stations (Cobb and Coleridge) are in SI. The transmission capacities of NI-HAY and HAY-NI are set to 1,000 MW and those of HAY-SI and SI-HAY are set to 1,040 MW, and they are assumed to be constant. Transmission loss is ignored.

3.3 Load

The total load in the three nodes is the total generation of generators in the power stations mentioned above in vSPD. The load in each node in each week is presented by three load blocks, peak, shoulder and off-peak, and the load and hours are defined in each load block.

1. The peak load time period is 6am-8am and 6pm-8pm in the weekdays.
2. The shoulder load time period is 8am-6pm and 8pm-10pm in the weekdays.
3. The off-peak load time period is 12am-6am and 10pm-12am in the weekdays and the whole days in the weekends.

As an example, the load and hours in load blocks in the first week of 2005 are presented in Table 2.

	Peak	Shoulder	Off-peak
Load in NI	29,804	103,400	98,378
Load in HAY	5,197	18,282	20,539
Load in SI	27,090	86,624	109,518
Hours	20	60	88

Table 2: Load (MWh) and hours in load blocks in the first week of 2005

3.3.1 Load block calculation

The load and hours in the load blocks are calculated as the follows.

1. The generation of generators in the power stations in question by trading periods in vSPD are used to calculate the generation in NI and SI by trading periods.

2. The flows of transmission lines between the nodes by trading periods in vSPD are used to calculate the flows from NI and HAY and from HAY and SI by trading periods.

3. The generation and flows are used to calculate the load by trading periods in the three nodes.

    (a) The load in NI is the generation in NI minus the flow from NI to HAY.

    (b) The load in HAY is the flow from NI to HAY minus the flow from HAY to SI.

    (c) The load in SI is the generation in SI plus the flow from HAY to SI.

    (d) The load in HAY is negative in a large number of trading periods in 2006. This occurs when the generation in HAY exceeds the demand in HAY in vSPD. However, the generators in HAY are not in the power stations in question. Thus the negative load are set to zero.

4. The load in each load block in each node is half of the total of load by trading periods in the node in the load block, and the hours are half of the number of trading periods in the load block.

3.3.2 Load inflation calculation

The load in load blocks can be lower than the real demand in the market due to demand reduction, e.g., in a national power saving campaign. When demand reduction occurs, there are high node prices. Thus if there are high prices in NI, HAY or SI, then the load in the node can be inflated, e.g., by 5%. The node prices in the OTA2201, HAY2201 and BEN2201 nodes in vSPD are used as the prices in NI, HAY and SI. Weekly load-weighted average prices in each load block and each node are calculated by multiplying the prices and load by

Node	Sector	2005	2006	2007	2008	2009	2010
NI, HAY	Industrial	37%	38%	35%	36%	35%	34%
NI, HAY	Commercial	25%	25%	27%	27%	27%	27%
NI, HAY	Residential	38%	37%	38%	37%	38%	39%
SI	Industrial	60%	60%	58%	58%	58%	57%
SI	Commercial	16%	16%	17%	18%	18%	18%
SI	Residential	24%	24%	25%	24%	24%	25%

Table 3: Proportions of sectors in load in each node for 2005 to 2010

Node	Sector	2011	2012	2013	2014	2015	2016
NI, HAY	Industrial	36%	36%	34%	35%	36%	36%
NI, HAY	Commercial	27%	27%	28%	28%	28%	28%
NI, HAY	Residential	37%	37%	38%	37%	37%	36%
SI	Industrial	58%	58%	57%	58%	58%	58%
SI	Commercial	18%	17%	18%	18%	18%	18%
SI	Residential	24%	24%	24%	24%	24%	24%

Table 4: Proportions of sectors in load in each node for 2011 to 2016

trading periods, calculating the total of these and dividing the total by the load in the load block. It is found that all prices are lower than 500. In fact, these prices are not much different from the weekly average prices. Thus there is not much demand reduction and the load is not inflated.

3.4 Load shedding

Load shedding at a node depends on the sector, segment and cost. The sectors are industrial, commercial and residential. The proportions of sectors in each node depend on the starting year of the planning horizon. The proportions used for 2005 to 2016 are presented in Table 3 and Table 4. The load in each sector is divided into three segments and the load shedding cost depends on the sector and segment. The segments and costs are presented in Table 5.

3.4.1 Calculation of proportions of sectors

The proportions of sectors in each node in each year are assumed to be the proportions of annual electricity consumptions of sectors in the region for that node in the previous year. Such proportions are assumed to be the same over

	Industrial			Commercial and residential		
Segment	5%	5%	90%	5%	5%	90%
Cost	1,000	2,000	10,000	2,000	4,000	10,000

Table 5: Segments and costs ($/MWh) in each sector

the entire nation except the Tiwai aluminium smelter that is an electricity user in the industrial sector in the South Island. These proportions are used for NI and HAY, and they are used along with the national electricity consumption, the proportion of South Island electricity consumption and the Tiwai aluminium smelter electricity consumption to calculate the proportions of sectors for SI.

The data for annual electricity consumptions by sectors from 2001 to 2016 and the data for annual electricity consumptions by regions in 2015 are available in MBIE 2018a. The proportions of electricity consumption by regions are assumed to be the same in each year and the data in 2015 is used for each year. The nominal electricity consumption of the Tiwai aluminium smelter is 572 MW that is available in NZAS 2018.

The proportions of the sectors for each year are calculated using the following steps.

1. The industrial consumption is calculated as the total of industrial consumption and agriculture/forest/fishing consumption in the data, and the commercial and residential consumptions are those in the data. The consumptions of the other sectors in the data are very small and thus ignored.

2. The national consumption is the total of consumption of the three sectors.

3. The aluminium smelter consumption is calculated using the nominal consumption.

4. The national consumption netting out the aluminium smelter consumption is calculated.

5. The proportions of sectors for NI and HAY are calculated using the consumption calculated in step 4 and the commercial and residential consumptions.

6. The South Island consumption is calculated from the South Island consumption proportion in 2015 and the national consumption.

7. The South Island consumption netting out the aluminium smelter consumption is calculated.

8. The South Island commercial and residential consumptions are calculated using the proportions calculated in step 5 and the consumption calculated in step 7.

9. The proportions of the sectors for SI are calculated from the consumptions calculated in steps 6 and 8.

3.4.2 Impact of load shedding costs

The load shedding costs are arbitrarily except that the costs for the high segments are the value of lost load, or VOLL, used in the electricity industry. The impact of load shedding costs is tested for 2005 by generating Benders cuts with the load shedding costs multiplied by different scaling factors that are 1, 0.5, and 0.25, running simulation with the Benders cuts with the load shedding costs, and comparing the total present costs up to each stage in simulation for every two sets of Benders cuts using paired t-test. It is found that the differences are statistically significant in many weeks and thus there are significant impact of load shedding costs.

3.5 Hydro power stations

3.5.1 Generating capacities

The generating capacities of hydro power stations are presented in Table 6. The generation capacities are available on the websites of companies that own the power stations except the eight power stations in the Waikato River and the Mangahao power station. The generation capacities of the nine power stations are available in EMI 2017a.

3.5.2 Conversion factors

The conversion factors of hydro power stations are presented in Table 7.

1. The conversion factors of power stations in the Waikato River, in Waitaki River except Tekapo A, Tekapo B, Ohau B and Ohau C, in Manapouri River and of Waikaremoana are calculated from the specific energy in EMI 2017e.

2. The conversion factors of Tekapo A, Tekapo B, Ohau B, Ohau C and power stations in the Clutha River are not available in EMI 2017e and thus they are calculated from the plant factors that are the averages in three years in EMI 2017c.

3. The specific energy and plant factors change over time but this is ignored. The specific energy/plant factors used for power stations in the Waikato River, Waitaki River, Clutha River and Manapouri River are those effective on May 23, 2011, June 1, 2011, September 1, 2010 and April 10, 2008 respectively.

4. The conversion factors of the remaining power stations are the data used in the EMBER 1.0 Project.

The conversion factors of all power stations are assumed to be constant. They are independent of the storage in reservoirs and head ponds. For instance, historical reservoir storage, natural inflows and historical spill flows of reservoirs and downstream power stations are used to calculate generating flows of the power stations, and the latter are used with the generation of generators in the power stations in vSPD to calculate conversion factors of the power stations. In the result (generated by Lea Kapelevich), there is no correlation between historical reservoir storage and the calculated conversion factors.

Power station	River / Type	Generating capacity
Arapuni	Waikato	196.7
Aratiatia	Waikato	78
Atiamuri	Waikato	84
Karapiro	Waikato	90
Maraetai	Waikato	360
Ohakuri	Waikato	112
Waipapa	Waikato	51
Whakamaru	Waikato	100
Aviemore	Waitaki	220
Benmore	Waitaki	540
Ohau A	Waitaki	264
Ohau B	Waitaki	212
Ohau C	Waitaki	212
Tekapo A	Waitaki	27
Tekapo B	Waitaki	160
Waitaki	Waitaki	105
Clyde	Clutha	432
Roxburgh	Clutha	320
Manapouri	Manapouri	800
Cobb	Run-of-river	32
Coleridge	Run-of-river	39
Mangahao	Run-of-river	42
Matahina	Run-of-river	80
Rangipo	Small hydro	120
Tokaanu	Small hydro	240
Waikaremoana	Small hydro	138

Table 6: Generating capacities (MW) of hydro power stations

Power station	River / Type	Conversion factor
Arapuni	Waikato	0.4622
Aratiatia	Waikato	0.284
Atiamuri	Waikato	0.1955
Karapiro	Waikato	0.2653
Maraetai	Waikato	0.5267
Ohakuri	Waikato	0.2783
Waipapa	Waikato	0.1386
Whakamaru	Waikato	0.3164
Aviemore	Waitaki	0.31
Benmore	Waitaki	0.8176
Ohau A	Waitaki	0.5004
Ohau B	Waitaki	0.4167
Ohau C	Waitaki	0.4167
Tekapo A	Waitaki	0.2322
Tekapo B	Waitaki	1.2847
Waitaki	Waitaki	0.1624
Clyde	Clutha	0.5181
Roxburgh	Clutha	0.4016
Manapouri	Manapouri	1.5314
Cobb	Run-of-river	4.405
Coleridge	Run-of-river	1.009
Mangahao	Run-of-river	2.53
Matahina	Run-of-river	0.595
Rangipo	Small hydro	1.96
Tokaanu	Small hydro	1.75
Waikaremoana	Small hydro	3.5348

Table 7: Conversion factors (MW/cumec) of hydro power stations

Scaling factor	Intercept	Slope
1/10,000	6,180.97	0.97541883

Table 8: Manapouri decision rule

3.5.3 Manapouri generation

Manapouri is operated under operational constraints that are difficult to model, e.g., different minimum flows at different time and 24-hour flows in different months for different purposes (see EMI 2017c). Thus Manapouri generation (MWh) is calculated using a decision rule in each week or ignored. The decision rule is a linear function of the total of the storage at the beginning of the week (initial storage, m3) and the inflow volume in the week (m3). The data used to derive the decision rule is the generation in vSPD, the storage that are available in EMI 2017d and the inflows that are available in EMI 2017b from 2005 to 2014. The storage and inflow volume are scaled down by a scaling factor and then a concave two-piece piecewise linear function is fitted to minimise the total of squares of fitted errors. The second piece is ignored as the slope is almost zero. The scaling factor, intercept and slope in the decision rule are presented in Table 8. On the other hand, if Manapouri generation is ignored, then the slope and intercept are set to zero, and the generation of generators in the Manapouri power station in vSPD is ignored in the calculation of load.

3.5.4 Generation of small and run-of-river hydro power stations

The generation of small hydro power stations (Rangipo, Tokaanu and Waikaremoana) and run-of-river hydro power stations (Cobb, Coleridge, Mangahao and Matahina) are assumed to depend on only inflows and they are calculated by multiplying the inflows by the conversion factors.

3.6 Thermal power stations

3.6.1 Generating capacities

The generation capacities of thermal power stations are presented in Table 9. The generation capacities are available on the websites of companies that own the power stations except New Plymouth 1-3 and Otahuhu B. The generating capacities of these four stations are available in EMI 2017a.

3.6.2 Heat rates

The heat rates and fuel type of thermal power stations are presented in Table 10. The heat rates are obtained from EMI 2017a except the Stratford peakers. The heat rate for the Stratford peakers is the heat rate in the EMBER 1.0 project.

Power station	Generating capacity
Huntly main 1	250
Huntly main 2	250
Huntly main 3	250
Huntly main 4	250
Huntly e3p	403
Huntly peaker	50.8
New Plymouth 1	120
New Plymouth 2	120
New Plymouth 3	120
Otahuhu B	380
Stratford peakers	200
Taranaki Combined Cycle	377
Whirinaki	155

Table 9: Generating capacities (MW) of thermal power stations

Power station	Heat rate	Fuel
Huntly main 1	10.3	coal
Huntly main 2	10.3	coal
Huntly main 3	10.3	coal
Huntly main 4	10.3	coal
Huntly e3p	7.2	natural gas
Huntly peaker	9.8	natural gas
New Plymouth 1	11	natural gas
New Plymouth 2	11	natural gas
New Plymouth 3	11	natural gas
Otahuhu B	7.45	natural gas
Stratford peakers	9.5	natural gas
Taranaki Combined Cycle	7.6	natural gas
Whirinaki	11	diesel

Table 10: Heat rates (GJ/MWh) and fuel types of thermal power stations

3.7 Power station deratings

The deratings of power stations in each week (MW) are the generating capacity losses due to outage in the week and they are assumed to be known at the beginning of the planning horizon. The derating for each power station in each week is calculated using

1. the confirmed and completed outage data in POCP 2018 if there is data available in the week
2. the historical offer quantities of generators in the power station in vSPD if there is no data in POCP 2018 in the week and the power station is one of the hydro power stations in the four river chains or the main thermal power stations

3.7.1 Calculation of deratings from outage data in POCP

The outage data used to calculate deratings are the confirmed and completed outage in generation for power stations owned by Contact, Genesis, Meridian, Mighty River or Trustpower from 2005 to 2017 in POCP 2018. Each outage defines the outage block that is either a power station or a unit in a power station, the start and end dates and time of outage, outage type that is either continuous or daily, capacity remaining and capacity loss. The total of capacity remaining and capacity loss for each power station/unit is used as the generating capacity of the power station/unit. In some outages the total is smaller but the capacity loss is used as it is. The capacity loss is not available in some outages and thus it is calculated as the generating capacity minus the capacity remaining. In two outages the dates and time are obviously erroneous as the start date is after the end date in one and the start time is after the end time in daily outage in the other, and thus these outages are ignored. The capacity losses by trading periods are calculated from the outage data and then deratings are calculated as the average of capacity losses by trading periods. In the calculation of capacity losses by trading periods, the following are worth noting.

1. The capacity loss depends on the length of time period in outage in the trading period.
2. The capacity loss of a power station is the total of capacity losses of the power station and the units in the power station in the outage block.
3. The capacity loss of NPLn is distributed to the capacity losses of the three New Plymouth power stations equally.
4. The capacity loss of Waikaremoana is the total of capacity losses of TUI, KTW and PRI.
5. On the days when daylight savings start, the capacity losses in trading periods 5 and 6 are set to zero.

6. On the days when daylight savings end, the capacity loss in trading period 5 is calculated using the outage at 2am-2:30am, and the capacity losses in trading periods 6 to 8 are calculated using the outage at 2:30am-3:00am.

Since the data in POCP 2018 is for planned outage, capacity loss due to unplanned outage is not accounted for in the deratings.

3.7.2 Calculation of deratings using historical offer quantities in vSPD

It is assumed that the total of offer quantities of generators in vSPD equals the generating capacities in each trading period. Thus the difference between the nominal generating capacity and the total of offer quantities is the capacity loss of the generator in the trading period. The capacity loss is set to zero if the nominal generation capacity is lower than the total of offer quantities. Then the weekly capacity loss of a power station is the average of capacity losses of generators in the power station by trading periods. Since the offer quantities are not known at the beginning of the planning horizon, the deratings are the average of weekly capacity losses in the same week in historical years except 2005. Deratings in 2005 are used for 2005 as it is the first year when gdx data files are available.

3.8 Short run marginal costs of power stations

The short run marginal cost (SRMC, \$/MWh) of a hydro power station is assumed to be zero, and that of a thermal power station is the total of the fuel cost multiplied by heat rate, the carbon cost multiplied by the heat rate, and the operating and maintenance cost.

3.8.1 Fuel cost

The fuel used in a thermal power station is coal, natural gas or diesel. Coal is supplied from stockpiles that are restocked under long-term contracts. Thus it is assumed that the cost is constant at 4. Natural gas is supplied by take-or-pay contracts. It is assumed that in social planning the supply can be secured and the costs are wholesale prices. The quarterly average prices of natural gas for wholesale are available in MBIE 2018b. The quarterly average prices of diesel for commercial in MBIE 2018b are used as the costs of diesel. The quarterly average prices are converted into real dollars in December 2015 and the converted prices are presented in Table 11. The weekly costs in the four 13 weeks in each year are the prices of the four quarters in the year respectively. Note that the fuel costs in the input of DOASA refer to the total of fuel costs and carbon costs.

High gas and coal costs are also used and the results are compared with the results with the fuel costs above. High gas costs of Contact and Genesis and high coal costs of Genesis in nominal dollars in 2009-2018 financial years are provided by Gluyas 2018. The high gas and coal costs in 2008-2017 calendar years in real dollars in December 2015 are calculated and presented in Table 12.

	Natural gas				Deisel			
Year	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
2005	4.80	4.45	4.19	5.42	24.61	26.57	28.55	27.74
2006	5.39	5.32	5.41	5.96	28.87	34.18	32.48	27.26
2007	6.21	6.28	6.30	5.87	26.00	27.42	27.88	31.06
2008	5.57	5.39	5.69	6.03	33.11	40.20	40.40	30.32
2009	7.23	7.58	7.52	7.43	26.56	24.32	25.50	25.44
2010	7.67	6.73	7.76	7.88	26.52	28.77	26.86	27.26
2011	7.39	7.23	7.31	6.23	30.13	34.09	29.40	31.06
2012	6.52	6.68	6.70	6.20	31.27	30.65	31.33	30.88
2013	6.82	6.43	6.34	6.39	30.73	28.45	30.11	29.28
2014	6.01	5.80	6.45	6.14	28.29	27.79	27.51	25.29
2015	5.55	5.72	4.88	5.04	21.73	22.50	21.84	19.88
2016	5.29	5.32	5.22	4.57	15.75	14.68	17.15	18.07
2017	5.71	4.62	5.42	5.51	19.58	20.14	19.95	23.78

Table 11: Quarterly average prices of natural gas and diesel ($/GJ) in real dollars in December 2015

1. The high gas and coal costs are converted into real dollars in December 2015.
2. In each calendar year, historical generation weighted average costs over the financial years part of which fall into the calendar year are calculated.
3. For coal, the average costs are used as the high costs.
4. For gas, in each calendar year, scaling factors are calculated by dividing the average costs by the average MBIE quarterly gas prices in the corresponding financial years, and then the MBIE quarterly gas prices in the calendar year are inflated by the scaling factors.

3.8.2 Carbon cost

The carbon cost is the cost of CO2 emission for each unit of fuel used by a thermal power station under the NZ Emission Trading Scheme. The electricity generation industry took part in the scheme on July 1, 2010, and weekly carbon costs are calculated from week 27 in 2010. The weekly carbon costs are calculated by multiplying the weekly NZU price of emission ($/tCO2e), the emission quantity from fuel (tCO2e/PJ) and a scaling factor of 1/1,000,000. NZU spot prices are available on Theecanmole 2018. The weekly NZU price in a week is the first spot price in the week, or the latest spot price before the week if no spot price is available in the week. Since two emission units are counted as one in the scheme before January 2013, the weekly NZU prices before week 1 of 2013 are divided by two. The weekly NZU prices are converted into real dollars

	Natural gas				coal
Year	Q1	Q2	Q3	Q4	Annual
2008	11.91	11.51	12.16	12.90	4.74
2009	12.36	12.96	12.86	12.71	4.84
2010	9.91	8.69	10.01	10.17	4.91
2011	9.54	9.32	9.42	8.03	4.74
2012	8.74	8.96	8.98	8.32	4.78
2013	9.54	9.00	8.87	8.94	4.82
2014	8.48	8.19	9.10	8.67	4.98
2015	7.83	8.07	6.89	7.12	5.41
2016	7.32	7.36	7.23	6.32	5.94
2017	7.48	6.05	7.10	7.22	6.02

Table 12: High costs of natural gas and coal ($/GJ) in real dollars in December 2015

Coal	Natural gas	Diesel
91,200	52,800	0

Table 13: Emission quantities from fuel (tCO2e/PJ)

in December 2015. The emission quantities from fuel are available on EA 2011 and they are presented in Table 13.

3.8.3 Operating and maintenance cost

The operating and maintenance costs (O&M cost) of thermal power stations are presented in Table 14. The costs are those used by the Generation Expansion Model used by the Electricity Commission (EC) that are available in PB 2009 except for New Plymouth 1-3 and Stratford peaks. The costs for New Plymouth 1-3 and Stratford peaks are those used in the EMBER 1.0 project. The costs are used as the costs in real dollar in December 2015 as it is suggested in PB 2009 that the costs do not change with inflation.

3.9 River-valley hydro network

The river-valley hydro network consists of reservoirs, head ponds, hydro power stations, spillways, canals and inflows in four river chains, Waikato River, Waitaki River, Clutha River and Manapouri River. The reservoirs consist of Taupo in Waikato River, Tekapo, Pukaki and Ohau in Waitaki River, Hawea in Clutha River and Manapouri (Lake Manapouri and Lake Te Anau) in Manapouri River. Lake Benmore is large, but since it is normally operated at and above 90% of storage capacity, the variation of storage is small and thus it is modelled as a head pond. The storage of head ponds are ignored.

Power station	Cost
Huntly main 1	9.6
Huntly main 2	9.6
Huntly main 3	9.6
Huntly main 4	9.6
Huntly e3p	4.25
Huntly peaker	6.4
New Plymouth 1	9.6
New Plymouth 2	9.6
New Plymouth 3	9.6
Otahuhu B	4.3
Stratford peakers	6.4
Taranaki Combined Cycle	4.3
Whirinaki	10

Table 14: Operating and maintenance costs ($/MWh) of thermal power stations

3.10 Reservoirs

The storage capacities and minimum storage of reservoirs are obtained from the storage data in consents in EMI 2017c. The storage capacities, effective time and type of storage are presented in Table 15. The active contingent storage of Tekapo and Hawea can be used when there is national shortage, and they are used as the minimum storage of Tekapo and Hawea and presented in Table 16. Moreover, the consented contingent storage in Ohau is used when there is forecast of large inflows and the storage of Pukaki under 24,190,000 is used with no generation from the generator in Tekapo A, but these are ignored. The storage capacities and minimum storage for a week are those in the last day of the week. However, the storage capacity and minimum storage of Tekapo in week 13 in a leap year are accidentally set to those in April instead of March.

3.11 Inflows

Weekly inflows are calculated using daily inflows that can be downloaded from EMI 2017b. Note that the inflows at Karapiro are calculated from those at Arapuni and a tributary factor as a large number of inflows at Karapiro in actual data are smaller than those at Aarapuni, implying possible errors in the actual data. Daily inflows at Waikaremoana in some days are negative but weekly inflows are all positive.

The set of inflows for sampling in all but the first week in the planning horizon are the weekly inflows in the same week in the 35 years before the starting year, and the probabilities of the inflows are equal. The weekly inflows are adjusted by a DIA 2 model to be close to the inflows in the first week to account for the persistence in inflows over weeks. Inflows are sampled independently in the forward passes.

Reservoir	Capacity	Effective time	Storage type
Taupo	855,400,000	all time	active
Tekapo	705,100,000	Jan-Feb, Oct-Dec	active and available contingent
	734,400,000	Mar	
	763,900,000	Apr, Aug	
	793,600,000	May	
	823,400,000	Jun-Jul	
	705,100,000	Sept	
Pukaki	2,335,920,000	Jan-Apr and Sept-Dec before 11/09/2012	active
	2,425,450,000	May-Aug before 11/09/2012	
	2,425,450,000	from 11/09/2012	
Ohau	48,070,000	all time	active and consented contingent
Hawea	1,405,820,000	all time	active and available contingent
Manapouri	1,029,230,000	all time	active

Table 15: Reservoir storage capacities (m3), effective time and storage type

Reservoir	Minimum	Effective time	Storage type
Tekapo	191,000,000	Jan-Mar, Oct-Dec	available contingent
Hawea	263,870,000	from 25/05/2007	available contingent

Table 16: Reservoir minimum storage (m3), effective time and storage type

Flow	Bound	In consent	DOASA
Taupo	lower	50	50
Karapiro	lower	148 in Jan-Mar 140 or 148 in Apr and Dec 140 in May-Nov	148
Ohau to Ruataniwha	lower	8 in May-Oct 12 in the other months	12
Waitaki	lower	120	120
Hawea	lower	10	10
Clyde to Roxburgh	lower	120 at 6:26am-19:49pm	67
Roxburgh	lower	250	250
Hawea	upper	200 in Feb-Aug 60 in the other months	200

Table 17: Flow lower bounds and upper bounds (cumec) in consents and used in DOASA

3.12 Flows

There are lower bounds and upper bounds on the flows in the river-valley hydro network. Some of the lower bounds and upper bounds are in consents in EMI 2017c and they are presented in Table 17, and the other are the data used in the EMBER 1.0 Project.

- The lower bounds of flows in Karapiro and from Ohau to Ruataniwha are set to 148 and 12 throughout the year respectively to cover the smaller lower bounds.
- The lower bound of flow from Clyde to Roxburgh is the daily average of lower bounds in the data.
- The upper bound of flow from Hawea is relaxed to 200 as it is observed that the historical flows from Hawea calculated using the generation of generators in the Clyde power station in vSPD and the inflows between Hawea and Clyde are higher than 200 in February-August sometimes but higher than 60 and up to 200 in the other months quite often.
- There are effective dates for the lower bounds and upper bounds in the data but they are ignored in DOASA.

Note that some bounds on flows in EMI 2017c are ignored as they can be substituted by other bounds, e.g., the upper bound of generating flows are substituted by generating capacity.

The penalty cost for the violation of lower bound is \$950/MWh and that for upper bound is \$50/MWh. The penalty costs are lower than the load shedding costs as it is assumed that meeting demand is more important than meeting flow bound constraints.

Break point	Slope
992.98	518.44
1505.8	379.93
1707.28	331.43
2073.32	251.86
2317.71	204.88
2622.99	153.09
2689.05	142.89
2833.47	121.85
2922.52	109.73
3100.39	87.48
3185.09	77.8
3464.98	50
3509.96	46.14
3624.85	37.02
3878.26	20.75

Table 18: Break points (GWh) and slopes ($/MWh) used to calculate terminal water value

3.13 Benders cuts and terminal water value

The water values in all but the last week are calculated using Benders cuts. The Benders cuts are linear functions of reservoir storage and each Benders cut consists of an intercept and a coefficient for each reservoir. The Benders cuts are generated in the backward passes.

The water value in the last week is the terminal water value. It is a piecewise linear function of the total energy in reservoir storage. The break points and slopes are defined in Table 18. The break points are those used in the EMBER 1.0 project. The slopes are calculated using the break points and the coefficients of a quadratic regression equation of the daily prices at the Benmore node against the total energy in storage of the six reservoirs. The daily prices at the Benmore node are available on EMI 2018a and the energy storage data of the six reservoirs are available in EMI 2010. The data in January to March in 2010 are used.

The terminal water value is not an accurate estimation of water value owing to that the regression equation will be different if different data is used and the energy in storage of Lake Benmore was accidentally included in the regression albeit it is small and fixed. Thus the impact of the terminal water value is tested for 2005 by generating Benders cuts with the terminal water value with different scaling factors that are 0.5, 1 and 4, running simulation with the Benders cuts with the terminal water value, and comparing the total present costs up to each stage in simulation for every two sets of Benders cuts using paired t-test. It is found that the differences are statistically significant in almost all weeks and thus there are significant impact of terminal water value. A better terminal water value can be developed by repeatedly running DOASA in a planning horizon of two identical years and updating the terminal water value using the Benders cuts at the end of the first year until the two converge. However, this is extremely time-consuming as this needs to be done many times when DOASA is used with moving horizon.

3.14 Risk aversion

DOASA can be run with risk aversion. In risk aversion, the probability of the inflow that results in the highest cost in stage problem is inflated and the probabilities of the other inflows are scaled down. The probability is set by a parameter of lambda. If lambda is set to zero, then DOASA is run with risk neutral.

4 Hydro vSPD

Hydro vSPD adapted from vSPD of version 1.4 is used for 2005 to 2014, and Hydro vSPD adapted from vSPD of version 2.0.5 is used from 2015. The data is from public sources, e.g., the EMI, the MBIE, and the data in the EMBER 1.0 project.

4.1 Planning horizon

The planning horizon is one day that consists of half-hourly trading periods in the day. There are 46 and 50 trading periods in the days when daylight savings start and end respectively and 48 trading periods in the other days.

4.2 Generators in hydro power stations in four river chains

The generators in the hydro power stations in the four river chains submit offers to the market. The generators are run at short run marginal costs that are assumed to be zero, and thus the offer prices are set to zero. The offer quantities are those in vSPD. The generation is bounded by ramping limits that are the maximum increase and decrease from the generation in the previous trading period.

The Manapouri power station is operated under operational constraints that are difficult to model, and thus the generation of generators in the Manapouri power station are fixed as the generation in vSPD.

The conversion factor of a hydro power station is used for the generators in the power station. The conversion factors and effective dates for the power stations in the Waikato River are presented in Table 19 and Table 20, and those in the other three river chains are presented in Table 21. The conversion factors of power stations in the Waikato River, Waitaki River except Tekapo A, Tekapo B, Ohau B and Ohau C, and Manapouri River are calculated from the specific energy in EMI 2017e. The conversion factors of those four power stations and

Power station	1/01/2005	14/04/2011	10/05/2011	11/05/2011
Aratiatia	0.284		0.2844	0.284
Ohakuri	0.2779	0.2783	0.2779	0.2783
Atiamuri	0.1958	0.1955	0.1958	0.1955
Whakamaru	0.3154	0.3164		0.3168
Maraetai	0.4979		0.4975	0.5152
Waipapa	0.1386			
Arapuni	0.4630		0.4741	
Karapiro	0.2653			

Table 19: Conversion factors (MW/cumec) and effective dates for hydro power stations in Waikato River before 13/05/2011

Power station	13/05/2011	23/05/2011	12/08/2013	8/04/2014
Aratiatia	0.2844	0.284		
Ohakuri	0.2779	0.2783	0.2779	0.284
Atiamuri	0.1958	0.1955	0.1958	
Whakamaru	0.3164			
Maraetai	0.5263	0.5267	0.5263	
Waipapa				
Arapuni		0.4622		
Karapiro			0.2639	

Table 20: Conversion factors (MW/cumec) and effective dates for hydro power stations in Waikato River from 13/05/2011

the power stations in the Clutha River are not available in EMI 2017e and thus they are calculated from the plant factors in EMI 2017c. The conversion factors change on the effective dates. The conversion factors are assumed to be independent of the storage of reservoirs and head ponds.

4.3 Generators in main thermal power stations

The generators in the main thermal power stations submit offers to the market. The generators are assumed to run on short run marginal costs and thus the offer prices are set to the short run marginal costs. The short run marginal costs are those used in DOASA except the short run marginal costs based on high gas costs that are calculated for Contact and Genesis separately. The high gas costs and coal costs in real dollars in December 2015 are presented in Table 22. The offer quantities are those in vSPD. The generation is bounded by ramping limits.

Power station	1/01/2005	10/04/2008	1/09/2010	1/06/2011
Tekapo A	0.2322			0.2322
Tekapo B	1.2821			1.2847
Ohau A	0.5004			0.5004
Ohau B	0.4167			0.4167
Ohau C	0.4167			0.4167
Benmore	0.8176			0.8176
Aviemore	0.31			0.31
Waitaki	0.1624			0.1624
Clyde	0.5181		0.5181	
Roxburgh	0.3968		0.4016	
Manapouri	1.4641	1.5314		

Table 21: Conversion factors (MW/cumec) and effective dates for hydro power stations in Waitaki River, Clutha River and Manapouri River

	Natural gas for Contact				Natural gas for Genesis				Coal
Year	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Annual
2008	6.68	6.46	6.82	7.23	18.63	18.01	19.02	20.17	4.74
2009	9.05	9.49	9.41	9.30	16.44	17.24	17.10	16.90	4.84
2010	9.85	8.64	9.95	10.11	9.98	8.76	10.08	10.24	4.91
2011	9.17	8.97	9.06	7.73	10.06	9.84	9.94	8.48	4.74
2012	8.27	8.48	8.49	7.87	9.47	9.71	9.72	9.01	4.78
2013	8.97	8.46	8.33	8.40	10.28	9.69	9.55	9.63	4.82
2014	8.07	7.79	8.66	8.25	8.86	8.56	9.51	9.06	4.98
2015	7.84	8.08	6.90	7.13	7.82	8.06	6.89	7.11	5.41
2016	7.08	7.13	7.00	6.12	7.44	7.48	7.35	6.43	5.94
2017	6.70	5.42	6.36	6.47	7.90	6.40	7.50	7.63	6.02

Table 22: High costs of natural gas and coal ($/GJ) in real dollars in December 2015

4.4 Generators with fixed generation

The generation of generators other than the generators in the hydro power stations in the four river chains and the main thermal power stations are fixed as the generation in vSPD. The offer prices are set to zero.

4.5 River-valley hydro network

The river-valley hydro network consists of reservoirs, head ponds, hydro power stations, canals, spillways and inflows in the Waikato River, Waitaki River, Clutha River and Manapouri River. The reservoirs are Taupo, Tekapo, Pukaki, Ohau, Hawea and Manapouri. The head ponds provide small storage capacities. Time delays in flows are ignored.

4.6 Reservoirs

The storage capacities of reservoirs are the same as those used in DOASA. The value of reservoir storage at the end of each day in each week is calculated using the Benders cuts generated for the week by DOASA.

Although Manapouri generation is fixed as the generation in vSPD, the Manapouri storage at the end of each day is different from the historical storage as the conversion factor is different. Furthermore, the historical storage can be higher than the storage capacity and Benders cuts do not provide good values for such high storage. Thus the Manapouri storage is set to the historical storage after the optimisation problem is solved.

4.7 Head ponds

The storage capacities of head ponds are presented in Table 23.

1. The storage capacities of head ponds in the Waikato River and of Ruataniwha, Aviemore and Waitaki are the active storage in consents in EMI 2017c.

2. The storage capacity of Benmore is 10% of the active storage in EMI 2017c as Benmore is operated at and above 90% of storage capacity generally.

3. The storage capacities of the other head ponds are not found in public sources and thus they are set to those used in the EMBER 1.0 Project.

The storage of head ponds at the beginning and the end of each day are assumed to be fixed at 50% of storage capacities. This prevents empty head ponds at the end of each day. The 50% is chosen so that there is storage space for the inflows and the flows released from upstream from mid-night to just before morning peak hours when demand is low.

Head pond	Storage capacity
Aratiatia	900,000
Ohakuri	27,400,000
Atiamuri	8,300,000
Whakamaru	17,500,000
Maraetai	17,200,000
Waipapa	6,000,000
Arapuni	31,400,000
Karapiro	19,100,000
Lake Scott	79,920
Tekapo B	10,751,132
Ruataniwha	1,440,000
Ohau C	43,215,676
Benmore	42,345,108
Aviemore	16,660,000
Waitaki	11,890,000
Dunstan/Clyde	25,200,000
Roxburgh	10,324,800

Table 23: Head pond storage capacities (m3)

4.8 Inflows

Inflows in each trading period in each day are set to the daily inflows as the former are not available in public sources. This ignores the variation of inflows during the day. The daily inflows are the inflow data available on EMI 2017b. The inflows at Karapiro are calculated from those at Arapuni and a tributary factor as a large number of inflows at Karapiro in actual data are smaller than those at Aarapuni, implying possible errors in the actual data.

4.9 Flows

There are lower bounds and upper bounds on the flows in the hydro network. The lower bounds and upper bounds and effective dates in consents in EMI 2017c are presented in Table 24. The lower bound of flow from Karapiro in April and December depends on the operation of Huntly power stations but it is set to 148 to cover the smaller lower bound. The effective dates are accounted for. The lower bounds and upper bounds that are not available in EMI 2017c are the data used in the EMBER 1.0 Project.

Penalty variables are used to allow violations of lower bounds and upper bounds. The effect of penalty costs on node prices should be as small as possible.

1. If the penalty cost is higher than the cost to meet demand, then the node price is the latter and thus not affected by the penalty cost.

2. If the penalty cost is lower than the cost to meet demand, then the flow

Flow	Bound	In consent	Effective date
Taupo	lower	50	12/04/2006
Aratiatia	lower	50	12/04/2006
Karapiro	lower	148 in Jan-Mar 140 or 148 in Apr and Dec 140 in May-Nov	12/04/2006
Ohau to Ruataniwha	lower	8 in May-Oct 12 in the other months	31/05/2011
Waitaki	lower	120	31/05/2011
Hawea	lower	10	25/05/2007
Clyde to Roxburgh	lower	120 at 6:26am-19:49pm	25/05/2007
Roxburgh	lower	250	25/05/2007
Hawea	upper	200 in Feb-Aug 60 in the other months	25/05/2007

Table 24: Lower bounds and upper bounds (cumec) of flows and effective dates

bound constraint may be violated, and the node price will be the penalty cost and thus underestimated.

3. If the flow bound is violated due to infeasibility, e.g., not enough water in upstream reservoirs and head ponds to meet flow lower bound, then the violation is not related to demand and thus penalty cost has no impact on node price.

Thus the penalty costs are set to high values, which are $1,000/MWh. The costs from penalty variables are calculated by multiplying the penalty variables by the penalty cost, the length of a trading period, and a high conversion factor (7 MW/cumec) that converts the penalty variables into energy.

4.10 HVDC risk and reserves

Hydro vSPD is run with HVDC risk and reserves, which is the most important risk. The offer quantities of partially loaded, tail water depressing and interruptible load reserves are set to the historical levels and the offer prices are set to zero. The HVDC pole ramp up is set to the historical level. The other reserves strongly depend on the offers to meet demand and thus they will be different from historical levels but these haven't been derived for Hydro vSPD. However, it is assumed that if vSPD is run with HVDC risk and reserves, then net free reserve will be available to meet reserve requirements. The minimum net free reserve required in the vSPD with HVDC risk and reserves is used in Hydro vSPD.

4.11 Solving methods

Multiple threads are used in the GAMS model option and the concurrent method is used in the Cplex option to allow the use of multiple methods in parallel to speed up the solving of optimisation problems. However, the concurrent method may fail to solve an optimisation problem, e.g., the Barrier method may return a solution with unscaled infeasibility that is likely related to the scaling of the optimisation problem. Thus if this occurs, then the dual simplex method is used to re-solve the problem, and if the dual simplex method fails, then the primal simplex method is used.

4.12 Guide to run Hydro vSPD

Hydro vSPD is run by running a macro in a spreadsheet or the runvSPD.gms file in GAMS in the Program_Mod folder. The macro generates the vSPDsettings.inc file that contains the settings selected in the spreadsheet, and vSPDsettings.inc is used by runvSPD.gms. The settings of Hydro vSPD with HVDC risk and reserves are those of vSPD with reserves that have been presented in Table 1, but the Resolve circular branch flows parameter is set to 0 which sets the resolveCircularBranchFlows and resolveHVDCNonPhysicalLosses parameters in vSPDsettings.inc to 0 so that the optimisation problems won't be solved as a mixed integer problem. If the Include reserves parameter is set to 0, which sets the useReserveModel parameter in vSPDsettings.inc to 0, then Hydro vSPD is run with no reserve. Note that it is recommended that the suppressOverrides parameter in vSPDsettings.inc is set to 1 manually to ignore the code of overriding demand and price.

The input can be changed in the following files.

1. In the Input folder
   (a) F.gdx for gdx data file, where F is the name of the file, e.g., FP_20050101
   (b) F_fuel_cost.csv in the fuel_cost folder for the total of fuel cost and carbon cost
   (c) F_OfferResults_TP.csv in the generation folder for the generation in vSPD
   (d) F_inflow in the inflow folder for the daily inflows
   (e) F_end_storage in the end_storage folder for the reservoir storage at the end of the day
   (f) BendersCuts_1_1.csv and BendersCuts_2_1.csv in the Cuts folder for the Benders cuts in two weeks
2. In the Programs_Mod folder
   (a) vSPDfileList.inc for the names of gdx data files
   (b) vSPDpaths.inc for runName that is the name of the folder for output

(c) RiverData.xls for the data of river-valley hydro network
(d) vSPD_boundary.gdx for the initial storage and initial generation of the first day

The vSPD_boundary.gdx file for the first day can be generated by running Hydro vSPD.

1. The initial storage is in the reservoirs.xlsx file in the Programs_Mod folder, and the parameter of useInitialStorage in the file is set to 1.

2. The initial generation is in the gdx data file in the Input folder.

3. Hydro vSPD is run and then terminated after vSPD_boundary.gdx has been generated.

4. The parameter of useInitialStorage in reservoirs.xlsx is changed back to 0.

Hydro vSPD generates output in csv files.

5 Experiment

5.1 DOASA and Hydro vSPD of different versions

DOASA and Hydro vSPD of different versions are used in different cases and they are presented in Table 25. The results of Hydro vSPD in the first three cases are compared with the result of vSPD with no reserve, and the results of Hydro vSPD in the last three cases are compared with the result of vSPD with reserves that is the historical market result.

5.2 Run DOASA and Hydro vSPD

In fixed hydro, Hydro vSPD is run for each day. In the other cases, DOASA and Hydro vSPD are run in moving horizons of two weeks.

1. The planning horizon is 52 weeks and the initial storage is set to be the historical initial storage.

2. DOASA is run with the planning horizon and initial storage.

3. Hydro vSPD is run for the first two weeks with the initial storage and the Benders cuts for the two weeks.

4. The planning horizon is moved forward by two weeks and the initial storage is set to be the storage at the end of the last day in Hydro vSPD.

5. Go back to step 2.

Case	DOASA	Hydro vSPD
Fixed hydro	Not needed	Fixed hydro generation and no reserve
Fixed Manapoouri	Manapouri is ignored, load is calculated from vSPD with no reserve, and risk neutral (lambda is 0)	No reserve
Manapouri decision rule	Manapouri decision rule, load is calculated from vSPD with no reserve, and risk neutral (lambda is 0)	No reserve
Risk neutral	Manapouri decision rule, load is calculated from vSPD with reserves, and risk neutral (lambda is 0)	HVDC risk and reserves
Mild risk aversion	Manapouri decision rule, load is calculated from vSPD with reserves, and mild risk aversion (lambda is 0.5)	HVDC risk and reserves
High risk aversion	Manapouri decision rule, load is calculated from vSPD with reserves, and high risk aversion (lambda is 0.9)	HVDC risk and reserves

Table 25: DOASA and Hydro vSPD in different cases

The moving horizon of two weeks enables DOASA to generate Benders cuts pertaining to the actual inflows in the first week in the planning horizon frequently.

It takes about one hour for one run of DOASA and one hour for one run of Hydro vSPD if the optimisation problems in Hydro vSPD are solved by the concurrent method.

5.3 Generate result from vSPD and Hydro vSPD output

5.3.1 Generation

Daily generation is available in the OfferResults.csv files. Note that on July 21, 2009, the daily generation of each generator in the file appears twice as the company of the generator is presented by its name and then by a numerical code.

5.3.2 Thermal costs

Weekly thermal costs are the total of weekly thermal costs of main thermal power stations. The latter are the total of daily thermal costs that are calculated by multiplying the daily generation by the short run marginal cost.

5.3.3 Node prices

Node prices of NI, HAY and SI are the prices at the nodes of OTA2201, HAY2201 and BEN2201 respectively. The prices by trading periods are obtained from the NodeResults_TP.csv files and they can be up to half million, particularly when there are demand violations. However, in reporting the node prices are capped by \$10,000/MWh if there are demand violations as the pay-out price by the Electricity Authority (EA) for demand violation is between \$10,000/MWh and \$20,000/MWh, and capped by \$1,000/MWh otherwise as 99.8% of historical node prices in trading periods without demand violation are less than this.

5.3.4 Revenues, costs and market rents of companies

The weekly revenue of a company is the total revenue over the generators owned by the company over the week, and the revenue from a generator is calculated by multiplying the generation of the generator by the price at the node to which the generator supplies energy. The companies are Contact, Genesis, Mercury, Meridian and Trustpower, and they own the hydro power stations in the four river chains, the main thermal power stations and numerous small power stations. Generation by trading periods are obtained from the OfferResults_TP.csv files. Node prices by trading periods are obtained from the NodeResults_TP.csv files, and again, they are capped. Note that the Tekapo A and Tekapo B power stations were transferred from Meridian to Genesis on June 1, 2011, and thus the ownerships of the revenues are changed.

The weekly costs of each company are the weekly thermal costs of thermal power stations owned by the company that are calculated using the daily generation and short run marginal costs of the thermal power stations. The weekly market rents for each company are calculated as the difference of the weekly revenues and the weekly thermal costs.

5.3.5 Demand violation

Demand violations by trading periods are obtained from the SummaryResults_TP.csv files.

5.3.6 Reservoir storage

For vSPD, the historical daily reservoir storage are used and they are available at EMI 2017d. For Hydro vSPD, the daily reservoir storage are obtained from the Levels.csv files.

5.3.7 End storage values

The end storage value of a year is calculated using the storage at the end of the year and the Benders cuts for the week in the last run of DOASA starting in the year. For vSPD, the storage is the historical storage, and for Hydro vSPD, it is the storage at the end of the last day in the last run of Hydro vSPD in the year.

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