Modelling assumptions for energy cost consultancy

A REPORT PREPARED FOR IPART

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1 Introduction

This report describes the key assumptions and data sources used in the energy cost modelling undertaken by Frontier Economics for the IPART retail price determination for 2007/08 to 2009/10. Assumptions already presented in the energy cost report are not repeated in this report.

2 Discount rate

The modelling assumes a nominal pre-tax, real discount rate of 8.6%.

3 Generation assumptions

3.1 EXISTING SCHEDULED PLANT

The generator assumptions shown in Table 1 represent the current supply conditions and approximate merit order of dispatch by NEM State. The capacities reflect Winter aggregate generation capability for each State, as provided in the 2006 SOO.[1] Generator's short run marginal costs are derived from those for 2005/2006 from a report to the IRPC and NEMMCO by ACIL Tasman. Prices are presented in real terms in 2006/07 dollars.

Region	Portfolio	Station	Marginal Cost	MW
NSW	Delta	Mt Piper	$13.59	1320
		Munmorah	$15.50	600
		Vales Pt B	$14.08	1320
		Wallerawang C	$14.71	1000
	Eraring	Eraring	$15.25	2800
		Shoalhaven	$0.00	0
	MacGen	Bayswater	$11.11	2760
		Hunter Valley GT	$261.67	51

1 Generators were derated during summer periods to reflect their lower operating capacities.

Region	Portfolio	Station	Marginal Cost	MW
		Liddell	$12.01	2090
	Redbank	Redbank	$10.92	150
	Sithe	Smithfield	$36.93	160
	Snowy	Blowering	$1.00	80
	TRU	Tallawarra	$32.47	400
QLD	CS	Callide B	$12.17	700
		Callide C1	$11.22	460
		Kogan Creek	$7.80	763
		Swanbank B	$15.57	500
		Swanbank E	$27.62	385
	Enertrade	Barcaldine GT	$58.32	50
		Collinsville	$19.04	187
		Gladstone	$13.87	1680
		Mt Stuart GT	$245.91	294
		Oakey GT	$62.66	320
		Townsville GT	$30.79	238
	InterGen	Callide C2	$11.22	460
		Millmerran	$8.55	860
	Origin	Roma GT	$55.32	68
	Stanwell	Barron Gorge	$1.00	60
		Kareeya	$1.00	88
		Mackay GT	$279.68	33
		Stanwell	$12.68	1440
	Tarong	Tarong	$12.13	1400
		Tarong North	$10.76	443

Region	Portfolio	Station	Marginal Cost	MW
		Wivenhoe	$0.00	20
	Wambo Power Ventures	Braemar	$46.74	475
SA	AGL	Angaston	$261.67	40
		Hallett	$72.51	192
	International Power	Dry Creek GT	$72.51	140
		Mintaro GT	$72.51	88
		Pelican Point	$30.19	474
		Port Lincoln	$300.47	48
		Snuggery	$90.53	63
	NRG	Northern	$17.14	535
		Osborne	$34.44	190
		Thomas Playford	$24.85	240
	Origin	Ladbroke Grove	$34.42	84
		Quarantine	$68.57	92
	TXU	Torrens Island A	$48.49	504
		Torrens Island B	$44.69	824
SNOWY	Snowy	Murray	$1.00	1560
		Tumut Lower	$1.00	1500
		Tumut Upper	$1.00	616
TAS	Hydro TAS	Bell Bay1	$51.39	114
		Bell Bay2	$51.39	114
		Hydro Tas	$1.00	2172

Region	Portfolio	Station	Marginal Cost	MW
VIC	AGL	Somerton	$52.33	144
		Southern Hydro	$1.00	484
	Duke	Bairnsdale	$44.45	90
	Energy Brix	Energy Brix Complex	$9.67	148
	International Power	Hazelwood	$2.34	1600
		Loy Yang B	$5.63	1000
	Loy Yang Power	Loy Yang A	$2.17	2090
	SECV	Anglesea	$6.78	155
	Snowy	Laverton North	$49.36	312
		Valley Power	$49.69	336
	TXU	Jeeralang A	$48.00	232
		Jeeralang B	$48.00	255
		Newport	$43.44	510
		Yallourn W	$2.41	1487

Table 1: Existing and committed generation capacity

3.2 MINIMUM STABLE GENERATION LEVELS

Table 2 shows the assumed minimum stable generation (MSG) levels for the key plant types (coal and gas) in each region. The model does not allow generation units to operate below this level. Plant is shutdown if it is required to operate below the MSG.

Table 2: Minimum stable generation levels

Region	Level (% of capacity)
Coal fired plant	
NSW	40%
VIC	65%
SA	40%
QLD	40%
Gas fired plant	
All regions	15%

Source: IRPC Stage One Report, Proposed SANI Interconnector, July 1999

3.3 OUTAGE RATES

Assumed forced outage rates and scheduled maintenance days per annum are shown in Table 3 for each region and three plant operation types.

Table 3: Forced outage rates (%) and planned maintenance days

Region	Classification	Annual maintenance (days).	Equivalent forced outage rate
NSW	Baseload	27	2.9%
	Intermediate	29	3.8%
	Hydro	4	3.5%
	Peaking	4	11.5%
QLD	Baseload	15	4.5%
	Intermediate	29	3.8%
	Hydro	16	8.3%
	Peaking	5	11.5%
SA	Baseload	2	4.1%
	Intermediate	15	3.8%
	Hydro	25	3.5%
	Peaking	3	28.4%
SNOWY	Intermediate	29	3.8%
	Hydro	14	1.8%
TAS	Intermediate	29	3.8%
	Hydro	16	2.4%
	Peaking	2	4.2%
VIC	Baseload	18	7.1%
	Intermediate	29	3.8%
	Hydro	25	3.5%
	Peaking	2	4.2%
OTHER	Angaston	3	27.8%
	Bell Bay	15	9.9%
	Bell Bay GT	5	25.9%
	Hunter Valley	4	25.9%
	Kogan Creek	15	5.5%
	Laverton North	15	25.9%
	Valley Power	2	25.9%
	Wambo	29	25.9%

Source: ROAM Consulting, Minimum Reserve Level Recalculation 2006 Assumptions Report, September 2006 and NEMMCO, ANTS Consultation Final Report, September 2006

Note: In accordance with the SOO, the forced outage rate is defined as the annual average rate, expressed as a percentage, at which equipment must be unexpectedly taken out of service, usually because of a fault in the equipment.

3.4 HYDRO PLANT ASSUMPTIONS

3.4.1 Energy constraints

Hydro plants are modelled as energy constrained. Their net output for an entire period is limited by an assumed maximum capacity factor. The hydro units and their energy constraints are listed Table 4.

Table 4: Hydro plant energy constraints

Station	Portfolio	Energy budget (capacity factor)
AGL Hydro (Southern)	AGL	26%
Barron Gorge	Stanwell	50%
Blowering	Snowy	25%
Hume	Eraring	50%
Hydro Tasmania	Hydro Tas	52%
Kareeya	Stanwell	35%
Shoalhaven	Eraring	15%
Snowy	Snowy	15.7%
Wivenhoe	Tarong	10%

Source: NSW Greenhouse Benchmarks Position Paper, Ministry of Energy and Utilities, December 2001.

3.5 HYDRO PUMPS

There are three pumping units modelled which are associated with the Shoalhaven, Wivenhoe and Snowy stations. The units and their pumping capacity are listed in Table 5.

Table 5: Pump units in the NEM

Pump	Station	Efficiency	Pump capacity (MW)
Shoalhaven Pump	Shoalhaven	70%	240
Wivenhoe Pump	Wivenhoe	70%	480
Snowy Pump	Snowy	70%	600

Source: NEMMCO list of generators and scheduled loads. Assumed Efficiencies.

4 New entrant options

The assumptions regarding the costs of new generation facilities are presented in Table 6. The fixed costs presented are in terms of an hourly cost per MW of capacity installed ($/MW/h) and are accrued over the economic life of the plant.

Table 6: New plant options (real 2006/07)

Plant type	Region	Variable Cost ($/MWh)	Fixed Cost ($/MW/h)
Brown coal[1]	VIC	$2.40	$27.04
Black coal[1]	NSW: NCEN	$8.75	$22.20
	SWNW	$10.64	$22.24
	QLD: CQ	$9.69	$24.65
	NQ	$10.16	$20.07
	SWQ	$7.80	$23.12
CCGT[1]	NSW: CAN	$34.26	$11.19
	NCEN	$32.47	$11.33
	SWNSW	$30.67	$11.60
	VIC: C	$25.93	$11.27
	LV	$25.56	$11.27
	MEL	$27.20	$11.14
	N	$32.23	$11.65
	QLD: CQ	$25.16	$14.03
	NQ	$26.30	$9.25
	SEQ	$25.58	$11.07
	SWQ	$23.71	$12.80
	SA: ADE	$30.28	$12.89
	N	$30.59	$13.59
	SE	$27.98	$12.88
	TAS	$34.22	$11.31
OCGT[1]	NSW: Liquid	$240.87	$6.75
	Gas	$57.85	
	VIC	$49.36	$6.75
	QLD	$46.74	$6.75
	SA	$54.33	$6.75

Plant type	Region	Variable Cost ($/MWh)	Fixed Cost ($/MW/h)
	TAS	$60.66	$6.75
Biomass[2]	all	$17.73	$40.99
Hydro[2]	all	$1.03	$22.61
Geothermal[2]	all	$2.36	$51.22
Wind[2]	all	$1.03	$21.88
Crop Waste[3]	all	$8.83	$42.39
Food, Ag & Other Waste[3]	all	$8.62	$129.93
Landfill gas[3]	all	$1.10	$66.56
Sewage gas (Municipal waste water)[3]	all	$1.10	$36.59
Wood waste[3]	all	$8.83	$44.10
Solar Hot Water[3]	all	$1.10	$59.16
Solar PV (Grid connected)[3]	all	$1.10	$110.07
Bagasse Cogen[3]	QLD, NSW	$16.56	$25.39
Energy crops[3]	all	$16.56	$44.10
Municipal Solid Waste Combustion[3]	all	$1.10	$92.89
Black Liquor[3]	all	$17.73	$41.75

Sources:

1. *ACIL Tasman, Report on NEM generator costs (Part 2) - A report to IRPC and NEMMCO,* February 2005.
2. *MMA, Impacts of a National Emissions Trading Scheme on Australia's Electricity Markets,* July 2006. *Lead time based on discussions with industry.*
3. *Office of the Renewable Energy Regulator: Modelling the price of Renewable Energy Certificates (IES December 2002).*

4.1 ENERGY CONSTRAINTS FOR NEW RENEWABLES

Certain types of plant technologies are limited in the amount of energy they can produce over a year. For example, wind turbine operation is dependent on prevailing wind conditions and hydro operation is dependent on the availability of water. The energy limitations assumed for new energy constrained plant are expressed as a maximum capacity factor and shown in Table 7.

Type	Region	Maximum capacity factor (MCF)
Wind	NSW	30%
	QLD	30%
	VIC	30%
	SA	40%
	TAS	40%
Geothermal	All	80%
Hydro	NSW	30%
	QLD	30%
	VIC	40%
	SA	30%
	TAS	30%

Table 7: Maximum capacity factors for new renewables

5 Interconnection assumptions

The NEM is modelled as an interconnected system with six pricing regions: SA, VIC, SNOWY, NSW, QLD and TAS. The following interconnectors linking these regions are modelled:

- Directlink;
- QNI;
- Snowy-NSW;
- Vic-Snowy;
- Vic-SA;
- MurrayLink; and
- Basslink.

5.1 LOSSES

Losses are modelled using marginal loss factor equations for flow over each interconnect. Intra regional losses are modelled using a static loss factor, which represents the losses between the connection point of a generator and the regional reference node. The marginal loss factors for the 2006/07 financial year and the marginal loss factor equations from NEMMCO are used.

6 Demand assumptions

To streamline the NEM-wide modelling, the analysis focused on 32 representative demand levels per year rather than a chronological modelling of each half hour in each year. The representative demand points were selected to cover the full range of possible demand levels in each NEM region, as well as capture the diversity of demand between the regions. Each demand point was weighted by its expected frequency of occurrence during the year so that yearly average results could be determined by adding the frequency-weighted outcomes for each demand point. As a result, the points of low and average demand, which occur frequently throughout the year, received a higher weighting than the peak demand points, which occur infrequently.

The electricity demand in each year was based on the medium growth, 50% probability of exceedence (POE) forecasts from NEMMCO's 2006 Statement of Opportunities (SOO).

6.1 TREATMENT OF EMBEDDED GENERATION AND DEMAND

The component of demand met by embedded and non-scheduled generation was estimated based on data released by NIEIR.[2] This extra energy and peak demand was then added to the NEMMCO forecast to arrive at a gross demand forecast. This was done as the plant that serves this demand also produced green energy certificates (MRET, NRET, VRET). As these schemes were explicitly modelled in this analysis, the demand needed to be included.

6.2 DEMAND SIDE PARTICIPATION

Demand side participation is modelled as operational at times of high prices. Table 8 lists the volume of demand side participation and the price above which the demand side options will be activated.

Table 8: DSP assumptions

Region	Volume (MW)	Price ($/MWh)
NSW	14	500
QLD	157	500
VIC	121	500
SA	42	500
TAS	0	-

2 *NIEIR, "Projections of embedded generation in the NEM, 2005," June 2005*

7 Greenhouse schemes

The following Greenhouse schemes are incorporated into the analysis.

7.1 MANDATORY RENEWABLE ENERGY TARGET

The Commonwealth MRET, which commenced on 1 April 2001 under the *Renewable Energy (Electricity) Act 2000*, requires the generation of 9,500 gigawatt hours of extra renewable electricity per year by 2010. The targets used in the modelling (Table 9) are adjusted to account for (a) Renewable Energy Certificates (RECs) produced outside the NEM, since the target is Australia-wide but the modelling is constrained to the NEM; and (b) to exclude estimated RECs produced by existing large hydro plant with baselines, since this is required for the purposes of the modelling process.

7.2 QUEENSLAND 13% GAS SCHEME

The Queensland Government has introduced a scheme requiring electricity consumers (with annual consumption less than 750 GWh) to purchase 13% of their energy from gas fired generation sources. The scheme commenced in 2005.

The forecast targets for gas generation in Queensland resulting from the scheme are given in Table 9 below. A penalty of $11/MWh applies to any shortfall in meeting the target.

These targets will be modelled with a constraint in the optimisation on total gas generation in Queensland in each year. A penalty cost of $15.71/MWh is included in the model to enforce the constraint, on the assumption that the Queensland Government would increase the penalty in the event the target was not being met.

7.3 NSW BENCHMARKS SCHEME

The NSW benchmark scheme, or NGAC scheme, subsidises abatement throughout the NEM as a consequence of generators with low emission intensities being dispatched. Existing generators who were eligible to create NGAC's were allocated a baseline and the targets presented in Table 9 are net of these baselines.

7.4 VICTORIAN RENEWABLE ENERGY TARGET SCHEME

The VRET scheme took effect on 1 January 2007. VRET operates by imposing a legal liability on relevant entities to support renewable energy electricity generation on, generally, large wholesale purchases of electricity. Unlike the MRET and NRET schemes, only Victorian generators are eligible to produce VRETs. The renewables target set for Victoria is 10% by 2016, or an additional 3274GWh. This ramps down to 2030, with a 15 yr limit per project. The GWh targets are presented in Table 9.

7.5 NSW RENEWABLE ENERGY TARGET

NSW has recently announced a renewable energy scheme that is essentially the same as the MRET scheme imposed by the Federal Government, with a renewables target in NSW of 10% by 2010 and 15% by 2020. The GWh targets are presented in Table 9; generation from all regions are eligible to create permits.

	Target				
Calendar year	**MRET (GWh)**	**VRET (GWh)**	**NRET (GWh)**	**GEC (GWh)**	**NGAC ($ktCO_2$-e)**
2007	3,305	-	-	5,086	1,728
2008	4,363	-	219	5,293	5,097
2009	5,513	306	658	5,479	6,754
2010	6,755	636	1,097	5,647	7,190

Table 9 Greenhouse policy constraints/targets

Sources: Victorian Renewable Energy Act (2006), Sec 66; *Frontier calculation based on data from IPART.and DEUS;*

8 Bidding assumptions

Frontier Economics' electricity market model, *SPARK,* was used to provide Frontier's view on likely spot prices in NSW over the determination period. *SPARK* applies the techniques of Game Theory to the electricity market, finding stable (or equilibrium) sets of bids for key strategic players in the NEM.

All major NEM generation portfolios were assumed to be able to bid strategically in the market with the aim of profit maximisation. As generator's profitability depends on any contract position, assumptions regarding the contract position of the strategic players were required.

It was assumed that the strategic players were contracted to 75% of capacity except for NSW state-owned generators and Snowy Hydro. NSW generators were assumed to be initially contracted at 65% of capacity, increasing over time in line with the roll-off of the ETEF to 75% of capacity. Snowy Hydro was assumed to be contracted at 60% of capacity, shared evenly between NSW and Victoria.

THE FRONTIER ECONOMICS NETWORK

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