DEMAND SIDE PARTICIPATION

2015 NATIONAL ELECTRICITY FORECASTING REPORT

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IMPORTANT NOTICE

Purpose

AEMO has prepared this document to provide information about demand side participation in the National Electricity Market. It is based on information available as at [1 June] 2015 unless otherwise stated.

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1. INTRODUCTION

This report is part of AEMO's 2015 National Electricity Forecasting Report (NEFR) documents. It provides AEMO's 2015 demand side participation (DSP) forecasts for all National Electricity Market (NEM) regions and the methodology used to develop them. The 2015 NEFR forecasts cover a 20-year outlook period from 2015-16 to 2034-35.

DSP can refer to a wide range of short-term demand responses by customers to electricity price signals and network reliability signals. In this report, it specifically means:

- Occasional DSP responding to different levels of high prices (market-driven response).
- Occasional DSP responding to critical system conditions (reliability-driven response).
- Occasional net demand reduction due to small non-scheduled generation at different levels of high prices (market-driven response).

2. 2015 DEMAND SIDE PARTICIPATION

2.1 2015 Demand Side Participation

Table 1 provides the estimated DSP available for each state from 2015–16 to 2034–35. These estimates exclude DSP for the LNG projects in Queensland (refer to section 2.2).

Table 1 Estimated available DSP

	NSW	QLD	SA	TAS	VIC Summer	VIC Winter
Prices > $300/MWh	24	58	37	2	74	74
Prices > $500/MWh	32	58	40	6	79	79
Prices > $1000/MWh	34	59	42	6	79	79
Prices > $7500/MWh	164	81	123	33	168	108
Prices = MPC	422	156	167	73	245	185

In NSW, it is estimated that up to 422MW of DSP is available in 2015–16 at times when the electricity wholesale price reaches the market price cap (MPC).[1] Queensland has up to 156MW available when prices reach the MPC, SA has 167MW and Tasmania has 73MW.

The 2015 estimates of DSP available in each state do not vary between summer and winter, except in Victoria. The differential between Summer DSP (245MW) and Winter DSP (185MW) at MPC levels arises from data obtained from the 2015 survey, in which Victorian DSP is taken from five critical peak pricing days that occur over the summer season.

2.2 The DSP forecast for LNG projects in Queensland

The emerging demand for electricity from liquefied natural gas (LNG) plants presents a new opportunity for DSP. Queensland Curtis LNG (QCLNG) commenced exports from its first LNG train on Curtis Island, near Gladstone, in January 2015. QCLNG is currently completing its second train and will soon be joined by two other export projects: Gladstone LNG (GLNG) and Australia Pacific LNG (APLNG). All six committed LNG trains, each capable of delivering about 3.9 to 4.5 million tonnes of LNG per year, are scheduled to be operational by 2016.

Based on research by Lewis Grey Advisory for AEMO, it is assumed that there is no DSP during the ramp-up period, because the LNG plants would prioritise their own operational matters over short-term commercial issues such as responding to high electricity pool prices. Once production reaches full capacity, the LNG plants would be expected to fine-tune cost savings and consider DSP by the gas processing plants (GPPs).

The critical price level triggers for LNG plants are different to those affecting large industrial loads or small non-scheduled generation. This is due to the price sensitivity of their production revenues to the export market. As LNG prices vary, so will the opportunity cost of LNG plants drawing electricity from the grid. APLNG, GLNG and QCLNG are thus expected to use a combination of net demand reduction methods to hedge against the risk from price variations.

[1] The MPC is the maximum spot price, as set by the National Electricity Rules. The MPC for 2015–16 is set at $13,888/MWh, which will apply from 1 July 2015.

The following is an extract from the report prepared by Lewis Grey Advisory[2], outlining the economics of grid powered compression and the implications on DSP:

> The value of gas for LNG considerably exceeds the cost of electricity to the GPPs, other than at very high pool prices. Electricity usage in the electrically driven GPPs is 7–8 MWh/TJ. The short run marginal value of each TJ at the GPP is defined by the short run netback value of LNG, which ranges from $5/GJ ($5,000/TJ) at low oil prices to $12/GJ ($12,000/TJ) at high oil prices. The short run value of electricity supply to the GPPs, assuming that there are few if any other short run variable costs other than electricity, therefore ranges from $625/MWh to $1,700/MWh. Consequently GPPs would be unlikely to voluntarily curtail electricity usage at pool prices below this range.
>
> At prices well below this level it could become profitable for LNG projects to divert gas from LNG to gas fired electricity generation, where there is any unutilised generation capacity. The marginal cost of gas fired generation with gas at $12/GJ, the upper end of its value as LNG, would be approximately $97/MWh for a typical combined cycle plant and $158/MWh for a typical open cycle plant. At pool prices above these levels it could therefore be profitable for LNG projects to divert gas from LNG to generation, either in plants owned by their operators (Darling Downs PS is owned by Origin, the upstream operator for APLNG, and Condamine PS is owned by QGC, the upstream operator for QCLNG) or by third parties.

In summary, gas diversion to generation is therefore likely to occur at prices lower than levels at which DSP is of interest.

GLNG and APLNG presently have gas turbines on-site, but it is assumed these are a temporary measure until electrification takes place (2016 for GLNG and 2017 for APLNG).

As the table below demonstrates, AEMO assumes an additional 200MW will be curtailed in a low DSP uptake situation, 400MW in a medium uptake scenario, and 600MW in a high uptake scenario.

Table 2 Estimated DSP for Queensland LNG from 2017–18

	Low uptake	Medium Uptake	High Uptake
Prices > $300/MWh	0	0	0
Prices > $500/MWh	0	0	0
Prices > $1000/MWh	0	100	100
Prices > $7500/MWh	0	100	100
Prices = MPC	200	400	600

2.3 Comparison with 2014 NEFR

The 2015 NEFR estimates of DSP differ significantly from the 2014 estimates, especially as the wholesale electricity price increases.

[2] Lewis Grey Advisory, 31 March 2015, Projections of Gas and Electricity Used in LNG, http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report/NEFR-Supplementary-Information

Table 3 2014 estimated available DSP for 2015-16:

	NSW	QLD	SA	TAS	VIC Summer	VIC Winter
Prices > $300/MWh	18	49	39	0	65	45
Prices > $500/MWh	22	49	41	5	77	57
Prices > $1000/MWh	24	51	43	5	83	63
Prices > $7500/MWh	80	61	126	37	214	140
Prices = MPC	214	123	147	56	336	262

The most marked difference between the 2014 and 2015 DSP estimates occurs in New South Wales, where the 2015 DSP estimate at the MPC level is 82% higher than the 2014 estimate. All other states, bar Victoria, have also increased from 2014 to 2015. The Victorian MPC DSP, in contrast, has declined by 27% in summer and 29% in winter.

To better understand these differences, the DSP estimates can be broken down into

- DSP from small non-scheduled generation (SNSG).
- DSP from large industrial load.
- DSP from smaller loads.

Unlike the 2014 DSP estimates, the 2015 estimates incorporate the effect of small non-scheduled generation (SNSG) as an offset to demand at the various price levels. Table 4 provides the DSP estimates arising from SNSG.

Table 4 2015 DSP from SNSG

	NSW	QLD	SA	TAS	VIC Summer	VIC Winter
Prices > $300/MWh	1	0	15	0	1	1
Prices > $500/MWh	1	0	15	0	2	2
Prices > $1000/MWh	1	0	16	0	2	2
Prices > $7500/MWh	4	3	20	0	2	2
Prices = MPC	94	10	41	13	13	13

SNSG at MPC levels accounts for 23% of New South Wales' total available DSP, equivalent to 94 MW. At 41 MW, South Australia has the second greatest level of DSP available from SNSG, followed by Tasmania, Queensland and Victoria.

Another key difference between the 2014 and 2015 DSP estimates is the incorporation of the survey. The 2015 DSP estimates are based on an updated survey that was conducted in April 2015 (refer to Section 3.2 for details). Survey results show that DSP at the MPC level has nearly doubled from 2014 to 2015 in New South Wales and has increased significantly in all other states:

Table 5 2015 DSP from the 2015 Survey

	NSW	QLD	SA	TAS	VIC Summer	VIC Winter
Prices > $300/MWh	0	46	15	0	68	68
Prices > $500/MWh	0	46	15	0	68	68
Prices > $1000/MWh	0	46	15	0	67	67
Prices > $7500/MWh	114	57	59	1	127	67
Prices = MPC	117	57	59	2	129	69

Table 6 2014 DSP from the 2013 Survey

	NSW	QLD	SA	TAS	VIC Summer	VIC Winter
Prices > $300/MWh	5	44	35	0	42	23
Prices > $500/MWh	5	44	35	0	42	24
Prices > $1000/MWh	5	45	35	0	42	24
Prices > $7500/MWh	61	46	36	0	123	53
Prices = MPC	64	48	36	0	124	55

Finally the DSP estimates derived from the large industrial data exhibit a greater responsiveness at higher price levels than in 2014. Tables 7 and 8 provide the DSP estimates attributed to large industrial load.

Table 7 2015 DSP from large industrial load

	NSW	QLD	SA	TAS	VIC Summer	VIC Winter
Prices > $300/MWh	23	12	7	2	6	6
Prices > $500/MWh	31	12	9	6	10	10
Prices > $1000/MWh	33	13	11	6	10	10
Prices > $7500/MWh	46	21	44	31	39	39
Prices = MPC	210	89	67	58	103	103

Table 8 2014 DSP from large industrial load

	NSW	QLD	SA	TAS	VIC Summer	VIC Winter
Prices > $300/MWh	14	9	5	0	25	23
Prices > $500/MWh	19	9	7	5	37	35
Prices > $1000/MWh	21	9	10	5	43	41
Prices > $7500/MWh	29	19	41	38	97	91
Prices = MPC	167	84	63	57	221	214

Victoria is an anomaly, in that its DSP estimates have actually declined from 2014 to 2015. This decline is driven by the closure of the Point Henry aluminium smelter.

3. DSP METHODOLOGY

AEMO produces forecasts of the available DSP for winter 2014 and summer 2014–15 separately for three segments:

- DSP from large industrial loads.
- DSP from non-large industrial loads.
- Net demand reductions due to small non-scheduled generation.

The estimated DSP from large industrial loads is calculated based on historically observed responses at various price levels. This is explained in detail in Section 3.1.

The estimated SNSG reducing net demand is calculated on historical price responses also using the method in Section 3.1, accounting for the opposite direction of the response.

The estimated response from the remaining load is based on a survey of network businesses and market participants and is explained in Section 3.2.

These estimates are added together for each NEM region to give the total expected DSP available at different price levels.

3.1 Estimate of available DSP from large industrial loads and SNSG

To determine the available DSP, AEMO calculates the expected DSP response (reduction in consumption for large industrial loads and increase in generation from SNSG) based on half-hourly metered data from January 2000 to March 2015.

3.1.1 Price level triggers

The response is assessed for different regional wholesale price levels:

- Prices above $300/MWh.
- Prices above $500/MWh.
- Prices above $1,000/MWh.
- Prices above $7,500/MWh.
- Prices at MPC.

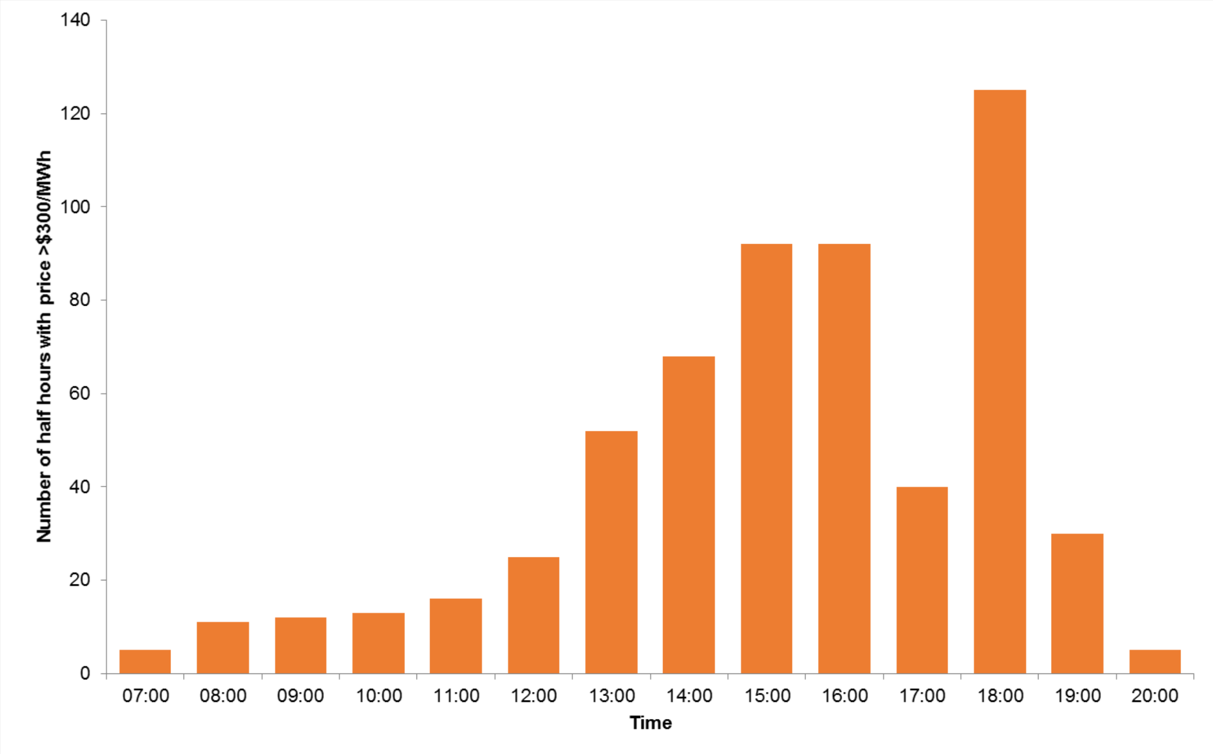
3.1.2 Relevant hours of demand

The response for large industrial loads is calculated as the difference between the demand observed in the hours where prices were in each of the bands identified above, and the average daytime demand for the same day.

For average daytime demand, AEMO only considers the hours from 7.00 am to 8.00 pm (local time) with prices below $300/MWh as this is when high price events generally occur (as shown for Victoria in Figure 1). Night-time industrial demand tends to be slightly higher, driven by lower night-time electricity prices, so comparing against a daily average that included price events outside 7.00 am to 8.00 pm would have introduced a bias which would lead to less accurate results.

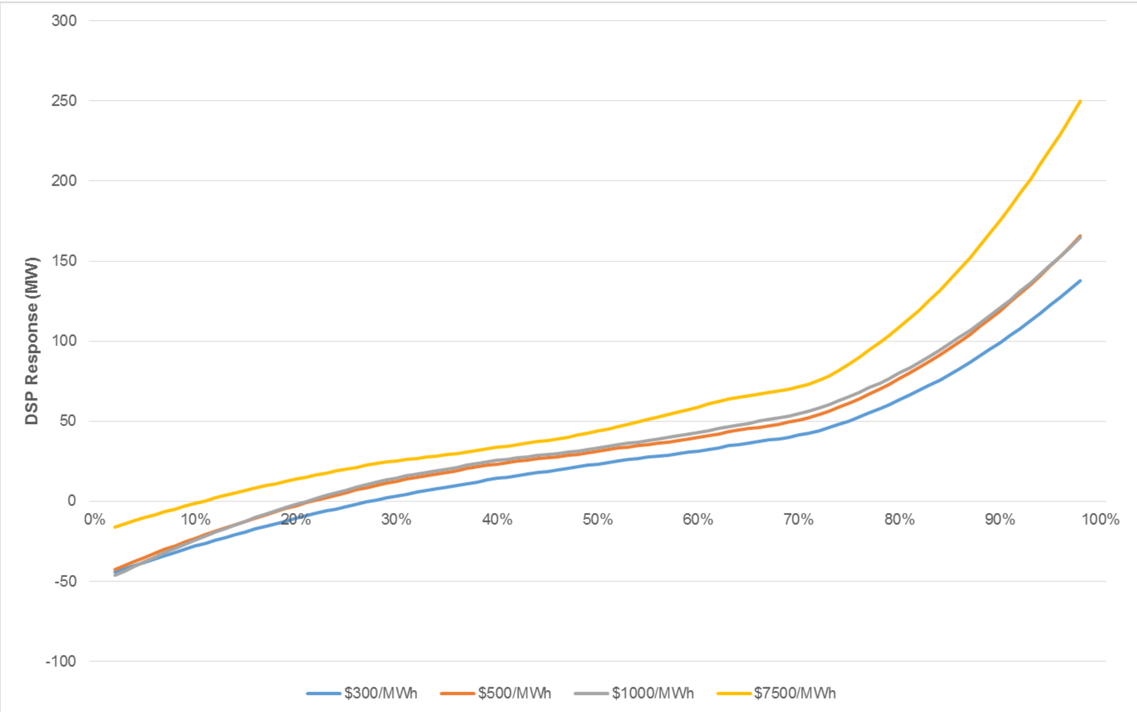
The response for SNSG is calculated as the difference between generation observed in the hours where prices were as listed above, and the average daytime generation for the same day. The distribution of high price occasions for Victoria is shown in Figure 1.

Figure 1 Half-hour intervals with prices above $300/MWh in Victoria (Jan 2000 to Mar 2015)



AEMO calculates the DSP response for each high price occasion. The number of high-price events enabled a reasonable estimate of the probability distribution of responses. This is shown for New South Wales in Figure 2. This figure shows the historically observed probability of response in megawatts.

Figure 2 Probability of DSP response in NSW based on historical responses (Jan 2000 to Mar 2014)



For example, 90% of the time when prices have been at or above $1,000/MWh, the historically observed DSP response has been at most 120 MW.

This assessment shows that DSP, at least from large industrial loads, is a probable resource rather than a firm resource. This is because industrial customer response depends on a range of factors, such as production commitment to its own customers and production flexibility. For these reasons, the same industrial customer may respond differently at different times.

3.1.3 Estimating DSP above $7500/MWh

Due to the limited data available because of the rarity of such events, it is not possible to reliably estimate the DSP response for prices above $7,500 using this approach. For use in reliability assessments, AEMO had to estimate DSP response during system crises, just before involuntary load shedding is required.

Prices would at that point equal the MPC. AEMO assumes that DSP response during system crises would be equal to the response seen in the 90–98% interval of the $7,500/MWh curve Figure 2 (the 98–100% interval is excluded from the analysis, as it includes outliers, including mandated load shedding).

Therefore, the lowest expected response equals the plotted value for 90% (corresponding to 10% probability of exceedance) and the highest expected response equals the value for 98%, with the midpoint (50% probability of exceedance) equal to the 94% value.

These regional estimates align with DSP forecasts for the 2014 NEFR and are consistent with actual responses seen in extreme pricing events.

Following this assessment, AEMO evaluates the impact of large industrial load on the maximum demand (MD) forecast to see if any historical price response might have interfered with the MD forecast calculations. This avoids double-counting of price impacts already accounted for in the MD forecast. AEMO found no evidence of DSP price responsiveness in the estimated MD for any NEM region and the DSP forecasts therefore should not be lowered.

3.2 Estimate of available DSP from smaller loads

As in the 2014 NEFR methodology, the DSP response from smaller loads is based on a survey undertaken by AEMO. In April 2015, AEMO surveyed network service providers (transmission and distribution), retailers, and DSP aggregators about the DSP available to them – both historical and forecast. Surveys were then collated, and the resulting data analysed to estimate the predictability and size of real-time regional price responses.

3.3 The combined DSP forecast for 2015–16

AEMO added the results from the large industrial analysis, small non-scheduled generation analysis, and the survey responses, to produce the combined DSP forecast, which is presented in this report. The risk of double-counting was mitigated by comparing the NMIs listed in the surveys to those taken from the large industrial and SNSG- analysis and removing any replications.

3.4 Assumed growth of DSP in the future

There is no assumed growth of DSP in the 20-year outlook period for the 2015 NEFR, defined as the sum of demand responses from large industrial loads, small industrial loads and small non-scheduled generation. Demand responses from LNG projects, on the other hand, are projected to vary according to their forecast maximum demands, access to site-specific generation and the expected timing for each project to reach stable production levels.

3.5 Modelling limitations and exclusions

The DSP forecast is subject to the following limitations and exclusions:

- The large industrial analysis is based on historical responses from January 2000, which will change with prevailing conditions. With electricity prices rising, AEMO expects that DSP responses would be higher today than in previous years, so the DSP is potentially underestimated.
- To ensure confidentiality of the capabilities and bidding behaviour of individual DSP resources (retailers, NSPs, large industrial loads), results have been presented in aggregated form. AEMO has sought to avoid any bias that may have been introduced into the forecast as a result of this aggregation.

3.6 Methodology improvements since 2014

The 2015 methodology differs from the 2014 methodology in one key respect: the incorporation of SNSG as an offset to demand at the various price triggers.