AUSTRALIAN ENERGY REGULATOR

Indicators of the market impact of transmission congestion

Report for 2003–04

9 June 2006

Contents

Summary

On 13 June 2006 the Australian Energy Regulator released its decision to publish indicators of the impact that transmission networks can have on the rest of the electricity market.[1] This is the first report in response to that decision. Future reports will build on any responses received on this and subsequent reports.

The aim of this report is to:

- identify the market impact and causal elements of constraints
- provide information to participants that will be used as a tool for guiding behavioural decisions, therefore promoting efficient market participant behaviour
- be used as a tool to develop possible economic incentives.

This report, for the period 2003–04, includes:

- the total cost of constraints (TCC)
- the marginal cost of constraints (MCC) together with a qualitative assessment of those constraints with high market impacts.

The TCC and MCC indicators are complementary. The TCC aims to estimate the cost of all transmission constraints. It does this by measuring the reduction in dispatch cost of generation that would occur if all transmission constraints were removed. It does not, however, identify the cause of these market impacts. The MCC examines the marginal value of individual constraint equations over time to identify the particular network elements that contribute to these market impacts. The TCC can indicate the quantum of the total market impact, while the MCC indicates the underlying cause at the margin.

In its qualitative assessment, this report focuses on the constraints identified as those having had a major impact during 2003–04 and explains the circumstances that led to these impacts.

Total cost of constraints

The TCC is an indicator designed to estimate the cost of all transmission constraints. Simply, the TCC is the answer to the question:

> If all transmission network limits were removed, how much would the total cost of generating sufficient electricity to meet demand be reduced?

During 2003–04 the TCC was $36 million with around 60 per cent of this accumulating on just nine days. Table 1 identifies for those nine days, the location of

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[1] *Indicators of the Market Impact of Transmission Congestion—Decision,* AER, 26 May 2006.

the network congestion, as identified by the MCC, which is most likely to have contributed to the TCC.

Table 1—High TCC events

Date	Locations	TCC
9/3/2004	Central to south Queensland; Victoria to Snowy; Hunter Valley outage (NSW)	$9m
21/2/2004	Victoria to Snowy	$2.5m
15/4/2004	Latrobe Valley to Melbourne	$2.2m
29/7/2003	Victoria to Snowy	$1.8m
8/2/2004	Queensland to New South Wales; and Victoria to South Australia and Victoria to Snowy	$1m
13/2/2004	Victoria to South Australia	$1m
2/7/2003	Victoria to Snowy	$1m
7/2/2004	Queensland to New South Wales; and Victoria to South Australia and Victoria to Snowy	$0.8m
20/6/2004	Victoria to Snowy; and Latrobe Valley (Vic)	$0.8m

Outage cost of constraints

The OCC measure is designed to estimate the cost of transmission constraints that can be directly linked to network outages (whether planned or unplanned). The OCC is closely related to the TCC. The OCC (as for the definition of the TCC above) is roughly the answer to the question:

> ‘How much lower would be the total cost of producing sufficient electricity to meet demand if all the limitations on the transmission network *due to outages* were removed?’

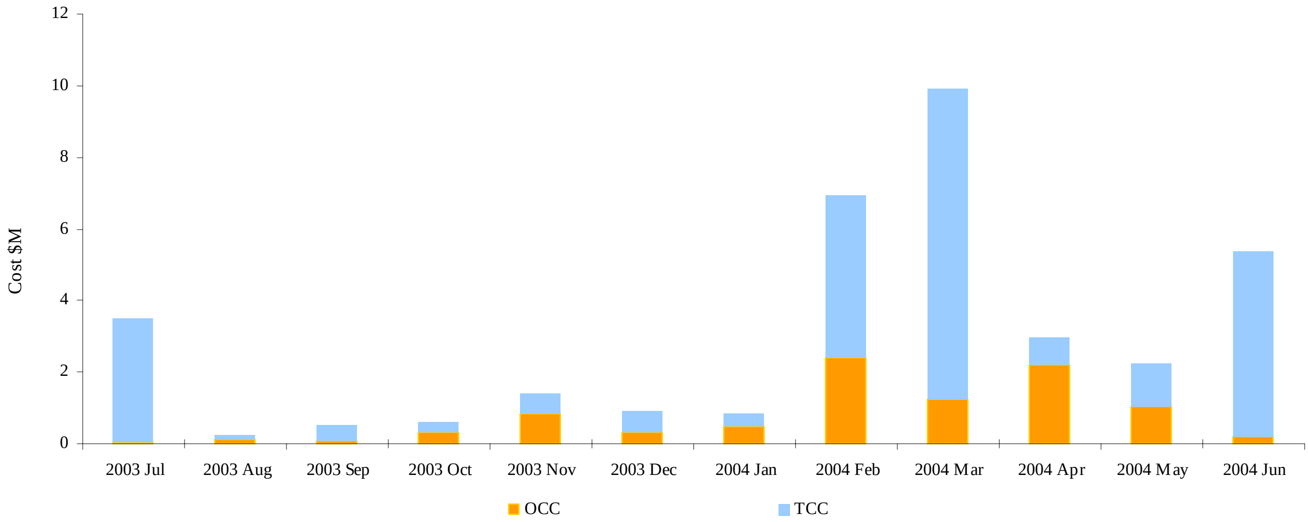
That is, the TCC is calculated by comparing the dispatch cost of the existing network with the dispatch cost of a hypothetical network without transmission constraints—and the OCC is calculated by comparing the dispatch cost of the existing network (including network outages) with the network in its ‘system normal’ state.

The OCC, like the TCC and MCC measures, values the cost of producing electricity using the prices at which each generator offers its output to the market. Like those other measures, therefore, it may be affected when a generator submits an offer that differs significantly from its own costs.

The estimated OCC for the period 2003–04 is $9 million or one quarter of the total TCC for the period.

Figure 1 shows the monthly breakdown of the TCC with the proportion attributed each month to the OCC. It identifies February and March as periods of significant network congestion. This corresponds to periods of high spot market turnover.

Figure 1—TCC and OCC by month



Marginal cost of constraints

The MCC is an indicator designed to identify the individual constraints that have significantly affected market outcomes. The MCC is derived by summing up the marginal constraint values reported with every constraint over the year. A single cumulative marginal value, analysed in isolation, provides little information. When the full set of constraints that bound over the year is compared, however, the relative severity of pinch points is revealed.

The MCC indicates that there were:

- 730 network constraints that affected the market with the majority being minor effects.
- five network constraints that significantly affected interconnectors. All interconnectors were impacted except for the New South Wales to Snowy interconnector, which was largely unaffected by network constraints over the period.
- seven constraints that significantly affected market outcomes within regions. All regions were affected except for South Australia where there were no significant intra-regional constraints.

Qualitative assessment

This analysis is undertaken to determine some of the key causes of network congestion.

The most significant network congestion in the market occurred on exports from Victoria into South Australia and Snowy and between the Latrobe Valley and Melbourne. These constraints reflect the inherent physical limitations of the network and did not result from outages of network equipment.

Lightning in the vicinity of the Heywood interconnector led to reduced flows into South Australia for a total of 33 hours.

Significant network congestion at times restricted flows from Queensland to New South Wales. These constraints reflect the inherent physical limits of the network and did not result from outages of network equipment.

Most network outages had little effect on market outcomes. A planned outage in New South Wales between Newcastle and Liddell on 9 March contributed to the extreme market outcomes on that day. Temperatures reached 40 degrees in Sydney driving demand to its highest level for that summer. This unusually hot March weather, combined with generator maintenance outages (aligned with the beginning of autumn) and the network outage, saw prices above $5000/MWh for two and a half hours. The TCC for the day reached $9 million or a quarter of the annual total. The same network outage occurred at other times during the year, with little market impact.

A number of supporting information sources have been provided as appendixes. These include: inter-regional settlement residues; frequency control ancillary service costs and the costs of directions over the year. These sources demonstrate a high correlation between the accumulation of settlement residues and the TCC. The high settlement residues generally occurred with the system in its normal configuration, that is, with no network outages. This is consistent with the MCC findings.

Unplanned network events led to significant impacts in the cost of frequency control ancillary services, and for the requirement for 10 power system directions.

1 Total cost of constraints

The TCC aims to estimate the cost of all transmission constraints. It does this by measuring the reduction in dispatch cost of generation that would occur if *all* transmission constraints were removed.

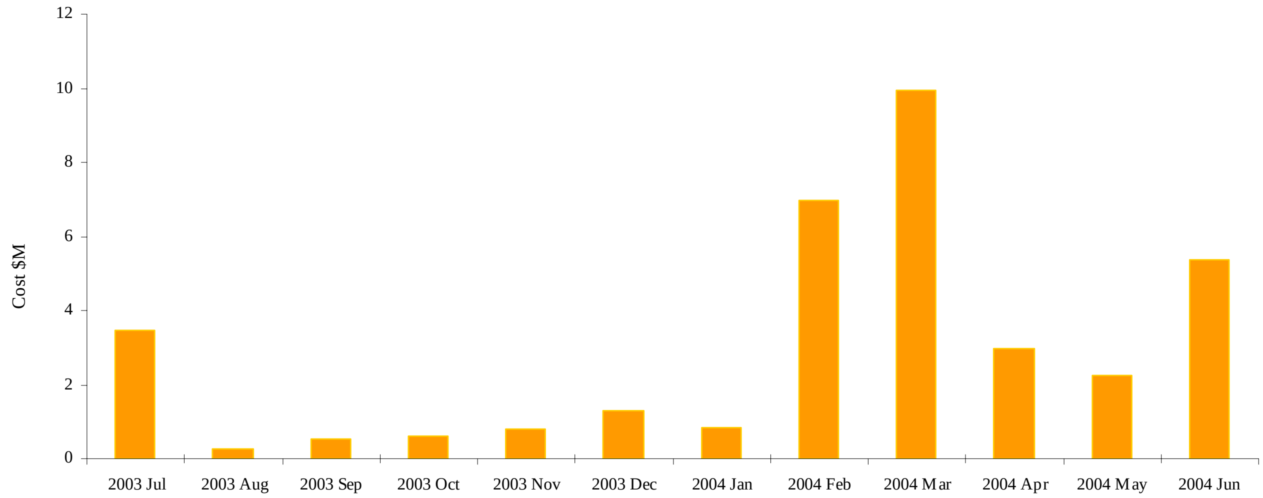
The TCC values the cost of generating electricity at the prices at which each generator offers its output to the market. Generators constrained by grid support arrangements do not have an incentive to offer their output at a price which reflects their own costs. To prevent distortions to the TCC, if it could be identified that a generator was operating under a grid support agreement, the impact of that generator was removed from the TCC. In other scenarios, when generators were affected by network congestion in a similar manner to grid support, the generators offers were replaced with a $300/MWh bid. Fortunately the number of generators in the situation was relatively small and mostly related to northern Queensland.

A detailed description of how the TCC is calculated is in the AER's decision, Indicators of the market impact of transmission congestion[2].

1.1 TCC results

The TCC for 2003–04 was $36m. Figure 2 shows the TCC for each month. Around 60 per cent of the total amount accumulated on just nine days of the year. Table 2 describes for each of those nine days the circumstances on the day.

Figure 2—TCC by month



2 ibid, appendix A and appendix B.

Table 2—Significant TCC events

Date	TCC	Description
Wednesday 2/7/03	$918 265	***Record demand in NSW*** Record demand and significant rebidding of capacity into higher prices resulted in spot prices of around $4500/MWh in NSW and Queensland during the evening peak. Flows northwards from Victoria were constrained to around 600 MW. At 6 pm the impact of these constraints was to constrain off 225 MW of Victorian and 511 MW of South Australian generation, which was replaced by generation in Snowy and NSW.
Tuesday 29/7/03	$1 866 009	***Record demand NSW*** New record demand in NSW in conjunction with reductions in available generation, in particular at Millmerran and Stanwell in Queensland and Vales Point in NSW, led to spot prices exceeded $1000/MWh over the evening peak. Exports from South Australia were constrained at the nominal limit of 300 MW over the evening peak with flows from Victoria into Snowy constrained to around 800 MW. At the peak, at 6.20 pm, around 450 MW of generation in Victoria and South Australia was constrained off.
Saturday 7/2/04	$880 389	***High Saturday demand in NSW and Queensland*** Prices in NSW exceeded $1000/MWh for two hours. On the same day, some 4000 MW, or almost a third of total capacity in NSW, was priced at more than $9000/MWh. Flows northwards from Victoria were constrained to around 600 MW as a result of an outage of the 500/330 kV F2 transformer at South Morang in Victoria and high ambient temperatures in northern Victoria. Flows into South Australia across Murraylink were also constrained to zero for much of the day as a result of the outage. Flows southwards from Queensland were at the nominal limit of 950 MW throughout the day.
Sunday 8/2/04	$1 091 901	***High Sunday demand NSW and Queensland*** Similar conditions to those on 7 February continued on Sunday 8 February. Discretionary constraints on the Victoria to Snowy interconnector and Murraylink were imposed for most of the afternoon.

Table 2—Significant TCC events

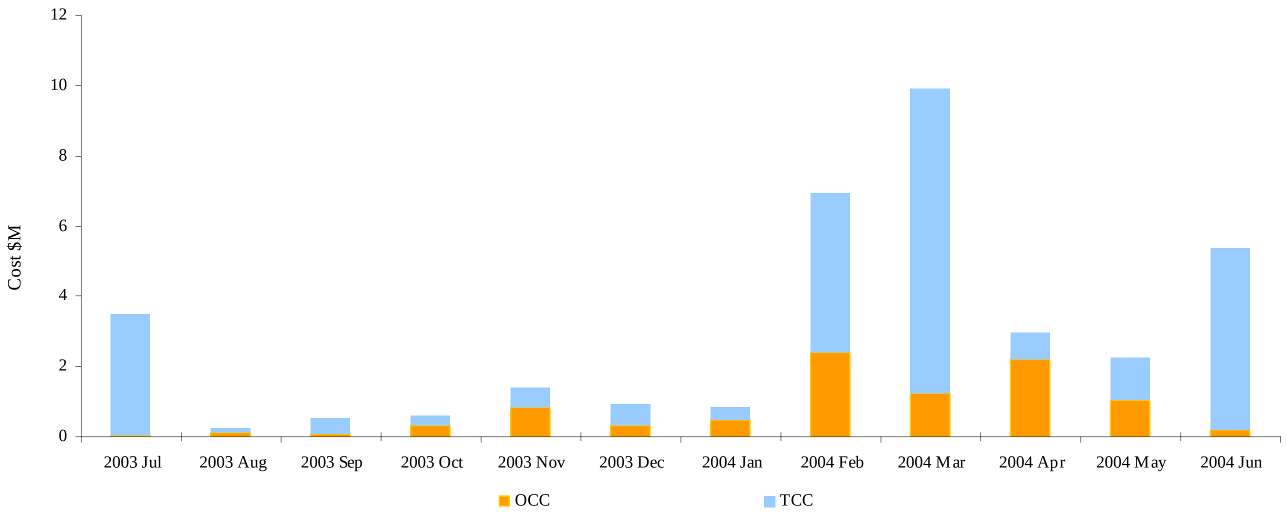
Date	TCC	Description
Friday 13/2/04	$978 009	***Low reserves and direction in South Australia*** Low reserve conditions in South Australia in conjunction with the unplanned loss of Murraylink resulted in a direction to Torrens Island for 1 hour late in the day. Intervention or 'What if' pricing was initiated. The Victoria to SA interconnector was constrained at its nominal limit of 460 MW.
Saturday 21/2/04	$2 459 106	***High demand and prices across the market*** Record weekend demands and high prices occurred across the market. Prices in Queensland, NSW and Snowy were aligned. Flows northwards from Victoria to Snowy were constrained to around 1000 MW.
Tuesday 9/3/04	$9 216 783	***High demand in Queensland and NSW*** Temperatures reached 40 degrees in Sydney, with prices exceeding $5000/MWh for two and a half hours in NSW and Queensland. Near-record demand and generator outages in both NSW and Queensland contributed. A planned network outage between Liddell and Newcastle in NSW affected the despatch of generation by up to 460 MW. Flows northwards from Victoria to Snowy were limited to around 1000 MW while flows from Snowy to NSW were constrained at the nominal limit of 3000 MW.
Thursday 15/4/04	$2 210 739	***Non-credible contingency in Victoria*** A non-credible contingency event occurred in Victoria resulting in the loss of a 500 kV bus at Hazelwood Terminal station in the Latrobe Valley. Discretionary constraints were invoked between 8.30 am and 1.30 pm to limit the level of Latrobe Valley generation to less than 2500 MW.
Sunday 20/6/04	$846 935	***High demand in Queensland and NSW*** High demand in Queensland and NSW with prices aligned in those regions. Flows from Snowy were unconstrained, while flows northwards from Victoria to Snowy were limited to around 800 MW. Constraints in the Latrobe Valley to limit transfers through the transformers at Hazelwood were binding during the same period. Exports from SA to Victoria across Murraylink were also constrained to between 70 MW and 120 MW.

2 Outage cost of constraints

2.1 OCC results

Almost one quarter of the TCC or $9 million is attributable to network outages (represented here as the outage cost of constraints or OCC). Figure 3 shows for each month the summated TCC and the proportion that has been allocated as arising from network outages.

Figure 3 –TCC and OCC by month



3 Marginal cost of constraints

The MCC is an indicator designed to estimate the market impact of individual constraint equations over time, to identify the network constraints (and associated network elements) that are causing significant market impacts.

The threshold for further assessment of inter-regional constraints with a cumulative marginal market impact over the year was set at $30 000/MW. For the case of intra-regional constraints the threshold was set at those that bound for more than 10 hours.

A detailed description of how the MCC is calculated, including the different nature of the marginal values reported for inter and intra-regional constraints is contained in the AER's decision, Indicators of the market impact of transmission congestion[3].

[3] ibid., appendix C.

3.1 MCC results

There are more than 13 000 network constraints in the market systems, with the number growing daily. During 2003–04 there were generally between 100 and 200 constraints invoked at any one time. Most, however, do not affect market outcomes and therefore have a zero marginal value. During the 2003–04 period there were around 730 constraints that affected the market at least once during this period, with around half classified as inter-regional and half as intra-regional. In assessing high impact constraints, where possible, constraints that related to the same network limitation were grouped. The details of all constraints that affected market outcomes are provided in appendix G.

There were 5 inter-regional network limits or constraints with a cumulative marginal value over the year of more than $30 000/MWh. Those constraints are detailed in table 3 along with the cumulative marginal value (CMV) and the duration.

Table 3—High impact inter-regional constraints

Constraint	Duration (hours)	CMV ($)	Type—description
VH>V3NIL VH>V4NIL	162	439 527	System normal—limit Victorian exports (Victoria to Snowy, and Murraylink) to manage thermal limit on Hazelwood—South Morang
VS_460	1321	423 129	System normal—460 MW limit on the Victoria to South Australia interconnector.
QN_950	173	71 436	System normal—950 MW limit on flows across the Queensland to NSW interconnector
Q:N_NIL_A	113	64 853	System normal—oscillatory stability limit for flows across the Queensland to NSW interconnector, for the loss of either the 8C or 8E lines between Armidale and Dumaresq with high Queensland demand
VS_250	33	36 528	System normal—250 MW limit on the Victoria to SA interconnector. Most frequently used when lightning is within the vicinity of the interconnector, leading to the reclassification of the loss of the interconnector from a non-credible contingency to a credible contingency.

There were seven intra-regional network limits or constraints that bound for more than 10 hours. Those constraints are detailed in table 4 along with the accumulated duration and whether the constraint was the result of a network outage or an inherent limitation (system normal configuration of the network).

Table 4—High impact intra-regional constraints

Constraint ID	Duration (hours)	Type—Description
V>V1NIL or V>V2NIL	163	System normal—Hazelwood transformer constraint, limits Latrobe Valley to Melbourne transfers. Yallourn unit 1 switched to either 220 kV or 500 kV network.
N>N-81__19	29	Outage—outage of 81 line between Liddell and Newcastle to manage overload of 82 line between Liddell and Tomago on trip of 32 line between Bayswater and Sydney West. Affects more than 10 000 MW of installed generation capacity in NSW.
#UPPTUMUT_E #TUMUT3_E	31	System normal—limits the output from Snowy Hydro generation, Upper Tumut and Lower Tumut. Limit changed a number of times.
Q>PRE855_871CAL Q>PRE855_871GL_ST	20	System normal—to manage flows on 871 line (in central Queensland) between Wurdong and Calvale for loss of 855 line between Calvale and Stanwell. Constrains Callide B and C (1540 MW) to less than a dynamically calculated limit.
Q>GD_BT_XFMR	17	Outage—outage of H7/T5 Bus Tie Transformer (in central Queensland) to maintain remaining bus tie transformer to within two hour ratings. Constraints on generation at Gladstone 3 and 4 to greater than 450 MW.
Q_GLD1200	12	Outage—constrains Gladstone (around 1680 MW of installed capacity) to generate at least 1200 MW.
N>N-22__03	10	Outage—outage of 22 line between Vales Point to Sydney North. The constraint is designed to manage overload of the 23 line between Vales Point and Munmorah on trip of 25 line between Eraring and Vinyard. Affects at least 11 520 MW of installed capacity. (Note: Redbank was added to the LHs in January 2004).

3.2 Qualitative assessment

This section provides further information on individual constraints highlighted in tables 3 and 4 as having a high market impact. This analysis has been performed to determine some of the key drivers to those impacts. The assessment includes commentary on the following:

- The accuracy of forecast outage information (including, the accuracy of timing and impact of those planned outages that resulted in significant MCC or TCCs).
- The impacts from unplanned outages (including short-notice outages).
- The accuracy of forecast network capability (targeting constraints with significant MCC or TCC) to focus efforts on continually improving the accuracy of forecast network capability.

- The impacts of network constraints on the cost of frequency control ancillary services (including the causes of the constraints) to reduce these impacts over time.

- Other factors that may affect the MCC and TCC, for example some constraints invoked to manage power system directions by NEMMCO or grid support.

The analysis of these constraints is presented in appendix B, and has led to the identification of locations of significant transmission congestion and the status of the network when this congestion occurred.

Significant network congestion occurred on exports from Victoria into South Australia and Snowy and between the Latrobe Valley and Melbourne. These constraints reflect the inherent physical limitations of the network and did not result from outages of network equipment. These constraints were identified in the above tables as: VH>V3NIL and VH>V4NIL limiting exports from Victoria to Snowy and South Australia; VS_460 limiting exports to South Australia and V>V1NIL and V>V2NIL which at times limited the supply of electricity from the Latrobe Valley to Melbourne.

Lightning in the vicinity of the Heywood interconnector led to reduced flows into South Australia for a total of 33 hours. These reduced limits were managed by the constraint VS_250 which set an export limit from Victoria into South Australia of 250 MW.

Significant network congestion at times restricted flows from Queensland to New South Wales. These constraints reflect the inherent physical limits of the network and did not result from outages of network equipment. These constraints are identified in the above tables as QN_950 and Q:N_NIL_A. When binding, these constraints limited exports to an average of 950 MW and 907 MW respectively.

Most network outages had minimal impact on market outcomes. A planned outage in New South Wales between Newcastle and Liddell on 9 March contributed to the extreme market outcomes on that day. This outage was managed by the constraint N>N-81__1. Temperatures reached 40 degrees in Sydney driving demand to its highest level for that summer. This unusually hot March weather, combined with generator maintenance outages (aligned with the beginning of autumn) and the network outage, saw prices above $5000/MWh for two and a half hours. The TCC for the day reached $9 million or a quarter of the annual total. The same network outage occurred at other times during the year, with little market impact.

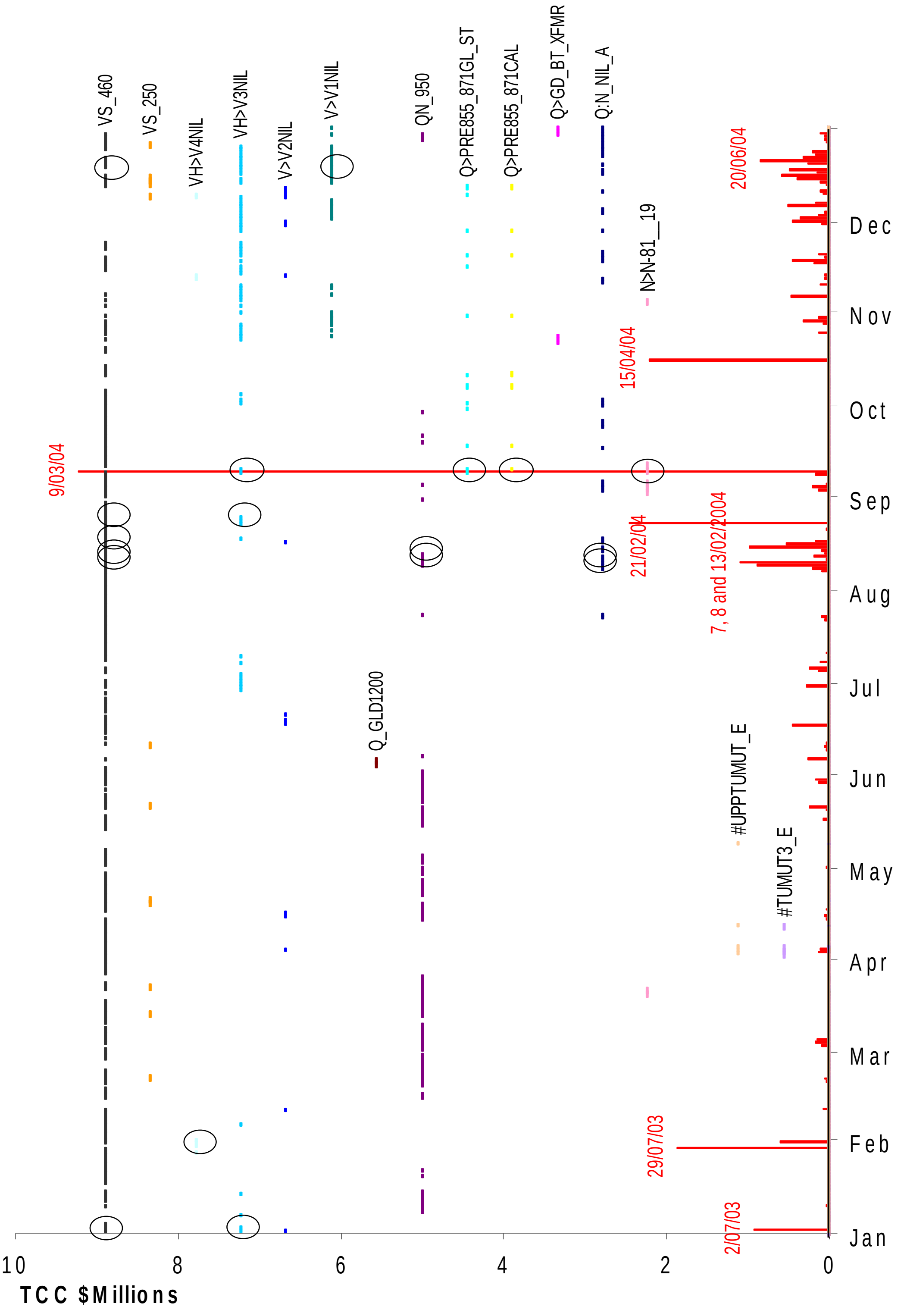
Several supporting information sources have been provided as appendixes. These include: inter-regional settlement residues; frequency control ancillary service costs and the costs of directions over the year. These sources demonstrate a high correlation between the accumulation of settlement residues and the TCC. The high settlement residues generally occurred with the system in its normal configuration, that is, with no network outages. This is consistent with the MCC findings.

Unplanned network events led to an increase in the cost of frequency control ancillary services of $9 million, and 10 power system directions with a cost of $4 million for the year.

Appendix A Daily TCC and significant network constraints

Figure A1 highlights the relationship between the TCC and the constraints analysed qualitatively in this report. It shows the TCC for each day during 2003–04, highlighting the top nine days, which are described in section 1. It also shows for the selected constraints, whether the constraint affected the market on that day, highlighting with circles those constraints leading to a marked effect and a high TCC.

Figure A1—Daily TCC and significant network constraints.



Appendix B Qualitative analysis

This section gives further information on individual constraints shown by the MCC indicator to have had a high market impact. This analysis aims to show what factors drove these constraints and led to significant congestion. The assessment includes comments on:

- the accuracy of forecast outage information (including the accuracy of timing and impact of those planned outages that resulted in significant MCC or TCCs).
- the impacts from unplanned outages (including short-notice outages).
- the accuracy of forecast network capability (targeting constraints with significant MCC or TCC) to focus efforts on continually improving the accuracy of forecast network capability.
- the impact of network constraints on the cost of frequency control ancillary services (including the causes of the constraints) to reduce those impacts over time.
- other factors that may affect the MCC and TCC, for example, some constraints are invoked to manage power system directions by NEMMCO or grid support.

This analysis draws on information published by NEMMCO through its market systems and through its website. The Network Outage Scheduler (NOS) is used by the TNSPs to identify the requirement for outages of transmission equipment. The NOS is published on the NEMMCO website[4]. The requested outages are assessed by specialist staff within NEMMCO and progressed to a ‘likely to proceed’ status (LTP) if it is deemed that the outage will not materially affect system security. At this stage, NEMMCO will determine for which constraints, if any, it will need to manage the security of the network during the outage. The constraint sets are then entered into the NOS and the market systems table ‘GenConSetInvoke’. Once in the market systems, the impacts of the network outage will be modelled in NEMMCO’s forecasts in pre-dispatch and short and medium-term PASA (projected assessment of system adequacy), which is up to two years in advance.

The constraints have been drawn from the list of constraints reported by the MCC as having had significant intra-regional or inter-regional impacts. Section B.1 details those constraints affecting interconnectors, while s. B.2 details constraints within regions.

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4 www.nemmco.com.au/transmission_distribution/NOS.htm.

B.1 Inter-regional constraints

B.1.1 Queensland to New South Wales interconnector (QNI)

Constraint: QN_950

This is a system normal constraint that sets a maximum limit of 950 MW on southward flows across the Queensland to New South Wales interconnector (QNI).

This constraint bound for a total of 173 hours, or 2 per cent of the time over 96 days during the year. The cumulative marginal value (CMV) for this constraint was $71 000. Over 90 per cent of the CMV for this constraint accrued over 7–8 February, when the constraint bound for around 19 hours. The spot price in New South Wales was above $900/MWh for five hours over the two days, however, in Queensland the spot price peaked at only $23/MWh.

This constraint was invoked for the whole period. The maximum capability for southward flows increased to 1078 MW on 12 November 2004.

Constraint: Q:N_NIL_A

This system normal constraint sets a dynamically calculated limit on southward flows across QNI. The constraint manages the flow for the loss of either the '8C' or '8E' lines (between Armidale and Dumaresq) in northern New South Wales at times of high demand in Queensland.

This constraint bound for a total of 113 hours or 1 per cent of the time over 45 days during the year. The CMV for this constraint was $65 000/MW and it set an average limit on QNI of 907 MW when it was binding.

Nearly 60 per cent of the CMV for this constraint accrued over 14–15 February. The constraint bound for a total of seven hours over these two days.

On 14 February the national demand was at near record levels for a weekend and the spot price on the day peaked in New South Wales at $1200/MWh. The spot price in Queensland was generally much lower, ranging between $50/MWh and $500/MWh with southward flows of almost 900 MW on QNI.

On 15 February there was record national and Queensland demand for a Sunday. During much of the day southward flows of close to 900 MW continued. The Queensland spot price climbed to $1000/MWh, aligning with the rest of the market by the early evening.

B.1.2 Victoria to Snowy interconnector

Constraint: VH>V3NIL and VH>V4NIL

These two system normal constraints manage flows across the South Morang 500/330 kV transformer by limiting flows out of Victoria across the Murraylink and the Victoria to Snowy (V-SN) interconnectors.

In the formulation of the constraint, Murraylink contributes with a factor of 0.626 and V-SN contributes with a factor of 1. That is, when these constraints are binding a reduction in Murraylink's limit by 1 MW allows for an increase in the V-SN limit by 0.626 MW.

These constraints bound for a total of 162 hours, or 2 per cent of the year, with VH>V3NIL accounting for 158 hours. The combined CMV for these constraints was $440 000/MW.

On 9 March these constraints were binding for nine hours, which coincided with high New South Wales spot prices. More than half of the CMV accumulated in this time.

B.1.3 Victoria to South Australia interconnector

Constraint: VS_460

The Victoria to South Australia (Heywood) interconnector was commissioned in 1990, via two 500/275 kV transformers at Heywood Terminal Station. For many years the interconnector operated with a nominal export capability of 500 MW.

In April 2003, after the rating of the transformer was jointly reassessed by NEMMCO and VENCorp, the capability of the interconnector was reduced from 500 MW to 460 MW. Subsequently, VENCorp, SPI PowerNet and the transformer manufacturer examined power system scenarios and transformer operating conditions to see if any increase in transfer capability would be possible.

From these studies VENCorp, as the TNSP responsible for advising on Victorian transfer limits, concluded that the 460 MW limit should remain in place

Constraint: VS_250

This constraint sets a maximum limit of 250 MW for flows from Victoria to South Australia across the Heywood interconnector. This constraint may be used during network outages affecting the interconnector but is mostly used to manage the reclassifications of the loss of the interconnector due to a credible contingency. These reclassifications typically occur when environmental conditions, such as lightning and bushfires, increase the likelihood of the simultaneous loss of both circuits of the interconnector.

This constraint was invoked on 12 days during the year. It bound for a total of 33 hours with a CMV of $37 000/MW. On every occasion during the period this constraint was used to manage lightning in the vicinity of the interconnector and the subsequent reclassification.

On each occasion, the use of this constraint led to unexpected and un-forecast limit reductions on the interconnector. NEMMCO published market notices on every occasion detailing the need for the changed limit immediately following the reclassifications.

B.2 Intra-regional constraints

B.2.1 Queensland

Constraint: Q_GLD1200

This constraint bound for a total of 12 hours over two days in December 2003.

The constraint requires generation at Gladstone to generate at least 1200 MW. It was invoked to manage network outages that occurred on 3 and 4 December 2003. On 3 December two circuit breakers around Gladstone and the number 811 line between Gladstone and Bouldercombe were removed from service for maintenance. On 4 December the 812 line, also between Gladstone and Bouldercombe, was removed from service for maintenance.

Powerlink advised of the requirement for the outages on 14 November, which is 19 and 20 days ahead of the outages. These outages were approved by NEMMCO and progressed to LTP status on the morning of the first outage on Wednesday 3 December.

Constraint: Q>GD_BT_XFMR

This constraint bound for a total of 17 hours on five separate days.

This constraint requires Gladstone units 3 and 4, around 550 MW of installed capacity, to generate at least 450 MW. The constraint was invoked to manage two maintenance outages of the Gladstone bus tie transformer. These outages occurred for three days commencing 21 April and from three days commencing 28 June. The constraint typically bound overnight during low load periods.

Notification by Powerlink of the requirement for the outages ranged between 18 and 29 days. The outages were approved by NEMMCO and progressed to LTP status on average 7 days before the planned commencement of the outages.

A third 3–day outage was planned to occur starting on 15 June. The requirement of the outage was first advised on 26 May, 20 days ahead and progressed to LTP status on 8 June (13 days later). The outage was, however, cancelled on 10 June.

B.2.2 New South Wales/Snowy

Constraint: N>N-81__19

This constraint manages the outage of the 81 line between Liddell and Newcastle. This line was removed from service on 20 separate days during the financial year. On nine of those occasions the constraint bound for a total of 29 hours. TransGrid gave, on average, 17 days notice of the requirement for the outage. The outages were approved by NEMMCO and progressed to LTP status on average nine days before the planned commencement.

Formulation The constraint directly affects over 11 500 MW of generating capacity within NSW. There is currently around 12 300 MW of installed capacity in that region.

The constraint has the effect of constraining on generation at Munmorah, Vales Point and Eraring (around 4500 MW) and constraining off generation at Mount Piper, Wallerawang, Bayswater and Liddell (around 7000 MW).

The largest factor on the left hand side is 0.319 with ratios between factors as high as six to one. With small factors on the left hand side, marginal values could go above $10 000/MW without violating the constraint.

The constraint was invoked through two sets N-LDNC_15M and N-LDNC_81 over the course of 2003–04.

The set N-LDNC_81 manages the outage of the 81 line and was used during March 2004.

The set N-LDNC_15M also manages the outage of the 81 line but uses 15-minute ratings on the 93 line (between Newcastle and Eraring). This set was used in September 2003 and May 2004.

Planning: The line was taken out of service on 20 days during the financial year, for daily outages typically between 7 am and 3.30 pm.

During September the set N-LDNC_15M was invoked on five days. This included four consecutive outages from Tuesday 16 September to Friday 19 September.

The requirement to remove the line, initially from Monday 15 September to Friday 19 September, was first notified on Tuesday 2 September, giving up to 17 days notice. The outage was approved by NEMMCO and progressed to LTP status between three and six days ahead. The outage planned for Monday 15 September was delayed several times and eventually cancelled. The constraint bound for a short period on Thursday 18 September and on Friday 19 September for six hours.

A market notice (MN 10 846) published at 5.12 pm on Thursday 18 September identified the need for additional discretionary constraints on the day to reduce flows from Queensland across QNI to manage the outage.

On Tuesday 23 September the constraint set was used to manage the reclassification of the loss of multiple lines as a result of bush fires in the vicinity (as detailed in market notice 10857).

During May the set was invoked on eight days between Tuesday 4 May and Friday 7 May and from Tuesday 11 May to Friday 14 May. The requirement for the outage was first notified on Thursday 22 April, giving between 12 and 22 days notice. The outage was progressed to LTP status on Saturday 27 April, between seven and 17 days ahead. The constraint bound on Tuesday 4 May.

In March the set N-LDNC_81 was invoked on consecutive days between Tuesday 2 March and Friday 5 March and between Tuesday 9 March and Friday 12 March. Notification of TransGrid’s requirement to remove the line was first identified between 12 and 23 days ahead, with the outages approved by NEMMCO and progressed to LTP status between 6 and 8 days ahead. The constraint bound on six occasions during this period. The most significant of those occurred on Tuesday 9 March, when demand in NSW peaked at 12 215 MW and temperatures reached

40 degrees. Prices in NSW peaked at $9700/MWh. The requirement for the outage on this day was first notified by TransGrid on 18 February, 20 days ahead. This outage was approved by NEMMCO and progressed to LTP status on 3 March, six days ahead. The outage was planned to occur between 6.50 am and 2.30 pm and aligned closely with this timetable. The constraint bound between 12.30 pm and 2.10 pm. The 5-minute prices, during the period the constraint bound, peaked at $7400/MWh. At times as much as 460 MW of generation capacity was constrained off, or driven down, by this constraint.

Some week-long, daily outages were originally planned to occur during late January and mid February. On two occasions these outages were cancelled the day before the outage was expected to begin. The March outages were substituted for these cancelled outages. TransGrid advised that the delay was to align the network outage with a planned outage of a Bayswater generating unit.

Constraint: N>N-22__03

This constraint manages outages of the 22 line between Vales Point and Sydney North. This line was removed from service for maintenance nine times during the period. On three of those times the constraint bound for a total of 10 hours. An average of 35 days notice was given by TransGrid of its requirement to remove the line from service, with the outages approved with LTP status on average within two days of receipt or 34 days ahead.

Formulation: The constraint directly affects over 11 500 MW of generation capacity within NSW. There is currently around 12 300 MW installed capacity in NSW.

The constraint had the effect of constraining on generation at Munmorah (around 600 MW of installed capacity), and constraining off generation at Mount Piper, Wallerawang, Vales Point, Bayswater, Liddell and Eraring and Redbank (a total of around 11 000 MW of installed capacity).

The largest factor on the left hand side is 0.585 with ratios between factors of up to almost six to one. With small factors on the left hand side, marginal values could go above $10 000 without violating the constraint.

The constraint was invoked through the set N-SNVP_22 during this period.

Planning: The line was out of service for nine days during the year. Eight of these outages occurred during January, with a further short notice outage in April.

TransGrid first gave notification of the requirement for the outages in January on 10 December giving between 34 days and 43 days notice. All of the outages were approved with LTP status within two days (on 12 December). The last of these outages, planned to occur on Friday 23 January, was cancelled on the afternoon of the previous day.

The constraint bound on three occasions for a total of 10 hours. On each of those occasions there was at least 30 days notice given. On 20 January the constraint bound for seven hours with prices in NSW peaking at around $80/MWh.

The other outage occurred on Saturday 3 April. The requirement for this outage was first notified by TransGrid one day before, after an aerial patrol identified damaged insulators in need of urgent maintenance. NEMMCO approved the outage, and raised it to LTP status on Friday 4 April.

Constraints: #TUMUT3_E and #UPPTUMUT_E

The discretionary constraints #TUMUT3_E and #UPPTUMUT_E were invoked on five days between 1 October and 6 November 2003 and bound for a combined total of 31 hours. These constraints restrict the output from Snowy Hydro’s Upper and Lower Tumut generators. At times, these constraints were invoked with other discretionary constraints which limited flows on the NSW to Snowy interconnector. The use of these constraints was sometimes detailed in market notices but no notice was given. The notices indicate that the constraints were used to manage post-contingent loadings in the Snowy region.

Formulation: The constraints have the effect of constraining off generation at Upper and Lower Tumut. At times Lower Tumut, which has about 1500 MW of installed capacity, was constrained below 150 MW and Upper Tumut, with an installed capacity of 600 MW, was constrained to below 200 MW. The right hand side of the constraints are varied by NEMMCO as required. This limit was changed as often as 11 times in one day.

Planning: The use of discretionary constraints is not planned. Their requirements arise from the failure of existing constraints to manage the secure operation of the network. This decision is made by NEMMCO through the use of on-line security assessment tools. There will always be the need for these discretionary constraints at short notice to manage security as a result of unforseen circumstances. Routine use of discretionary constraints, however, would indicate that the underlying constraints are ineffective. Accurate and timely information must be given to the market detailing the need for the constraints, estimates of the time they will apply and the expected impacts. The ineffective constraints must then be rectified to ensure the use of discretionary constraints is minimised.

The constraints were first used on Wednesday 1 October between 2 pm and 5 pm. A market notice (MN 10882) was published on Thursday (the following day), explaining that network power flows had exceeded limits and that flows between Upper and Lower Tumut and Murray were reduced to manage post-contingent flows within the Snowy region.

On Thursday 2 October, these constraints were again used, together with another discretionary constraint, which restricted flows on the NSW to Snowy interconnector. The constraint limited flow south to as low as 400 MW. These constraints were used over two periods between 7 am and 10 am and between 2 pm and 4 pm. A market notice (MN 10883) was published at 4.40 pm after the constraints were revoked.

On Friday 3 October these constraints were needed again and bound for almost three hours. No market notice was published.

On Friday 10 October these constraints were needed between 11 am and 6 pm, together with the constraint on the interconnector. Two market notices (MN 10895 and 10896) were published on the day explaining the use of the discretionary constraints. The first was published at 4.30 pm, forecasting an end to the use of these constraints at 5 pm. The second market notice, at 6 pm notified the need for the constraints for a further hour to 6 pm.

On Thursday 6 November, constraints were applied in the Snowy region from 7 am. This included the constraint #UPPTUMUT_E from 8.30 am with other discretionary constraints applied to the NSW to Snowy interconnector. These limits lasted until around midday. A market notice (MN 10987) was published shortly after midday. Later on the day, these constraints were required again. No market notice was published covering the second requirement.

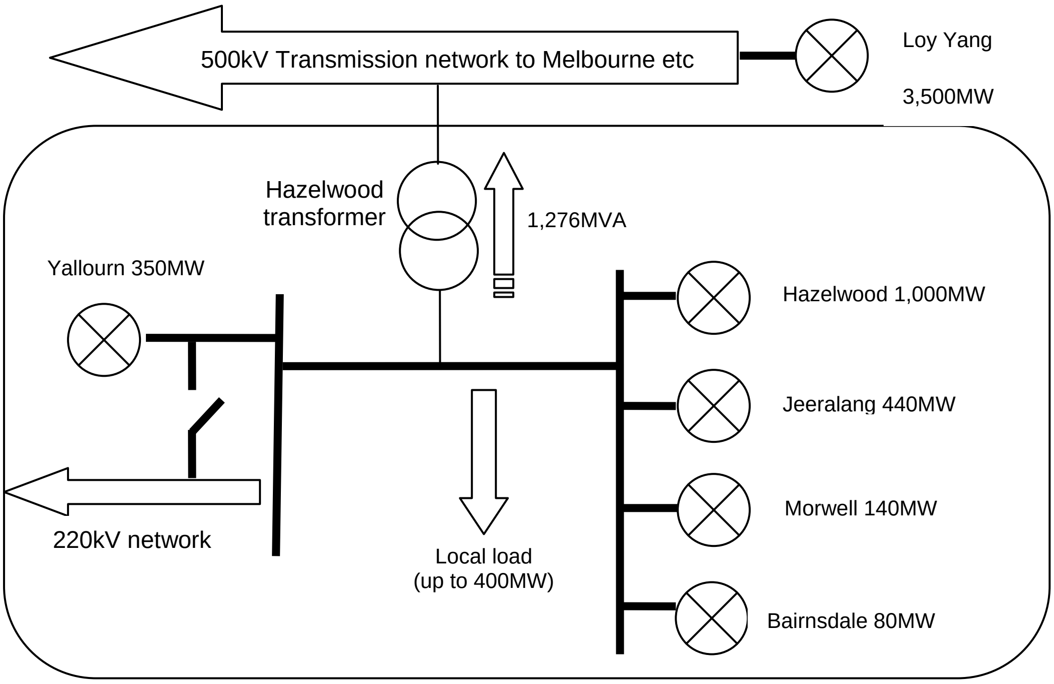
B.2.3 Victoria

Constraint: V>V1NIL and V>V2NIL

During 2003–04 this constraint bound on 48 days, with 40 of these between April and the end of June 2004, for a total of 163 hours. The average marginal value was as high as $1000/MW. This reflects that the constraint will constrain off generation across a number of portfolios, with competition for dispatch typically leading to capacity being shifted to prices of $–1000/MWh.

Background: Power is transported from the Latrobe Valley (the generation hub of Victoria) to the main load centre of Melbourne and neighbouring regions by the 500 kV and 220 kV transmission systems. The 220/500 kV transformers at Hazelwood restrict transfers between the 220 kV and 500 kV systems in the Latrobe Valley to a maximum of some 1276 MW. This means that under certain conditions, generation from Hazelwood, Jeeralang, Morwell, Bairnsdale and Yallourn unit 1 is constrained off to avoid a transformer overloading for the contingent loss of any of the four transformers. The combined capacity of these generators is 2600 MW. In July 2000, Yallourn Energy funded network changes to allow one of its units to be switched between the 220 kV and 500 kV networks, significantly improving its loss factor. With Yallourn capacity connected via the Hazelwood transformers to the 500 kV network, the constraint problem is exacerbated. Figure B1 sets out the configuration of generation and the transmission network in the Latrobe Valley. It highlights the amount of generation behind the limitation presented by the Hazelwood transformers.

Figure B1—Configuration of the generation and network in the Latrobe Valley



Generators affected by these constraints used several strategies to maintain their output. This included significant use of the dispatch inflexibility[5], or 'must run', provisions, offering zero ramp rates or using ancillary service offers to limit the impact of the constraint. All of these strategies, however, reduce the amount of generation available to manage the security of the network. These rebidding strategies prompted a technical investigation at the time into the nature and likely duration of the abnormal plant conditions across generators in the Latrobe Valley to justify the use of the 'must run' provisions.

VENCorp, and SP AusNet, in conjunction with the participants affected by the constraints, are exploring options to address this transformer limit issue, including the following:

1. Installation of a control scheme to trip specific generation following a forced transformer outage
2. Installation of a fifth 220/500 kV transformer at Hazelwood

[5] It is crucial to the efficiency, and indeed ultimately the security, of the market that the 'must run' provisions are used only in response to genuine technical operating requirements. Units declared inflexible or with ramp rates of zero are treated outside the normal pricing and despatch arrangements. This in turn limits the market's ability to achieve competitive outcomes. Moreover, abuse of those provisions could potentially threaten the safe and/or secure operation of the power system. At the extreme, it could lead to market failure and to intervention by NEMMCO to manage the operation of the system by direction.

VENCorp is currently addressing a number of technical issues to ensure the feasibility of these options. When these issues are addressed, VENCorp will undertake a detailed regulatory test assessment to determine the option which delivers the maximum net market benefit.

Formulation: These constraints affect up to around 2600 MW of installed capacity in the Latrobe Valley by limiting the combined maximum output to 1276 MW. This includes generation at Morwell, Bairnsdale, Hazelwood (units 1, 2, 6, 7 and 8) Jeeralang and Yallourn (unit 1).

Yallourn unit 1 is on the left hand side of the constraint V>V1NIL. This constraint takes effect only when unit 1 is switched to the 500 kV network.

A change to the formulation of this constraint in July 2004 increased the right hand side value by around 76 MW. The limit was increased through provision of an additional rating for 1 hour operation. This enables the transformers to be operated at a higher level for periods of up to an hour.

Planning: These constraints are system normal constraints and are invoked continuously.

The Yallourn unit is only able to be switched between the two networks at times of low to moderate Latrobe Valley generation. This restriction is related to the phase angle across the open 220kV circuit breaker which increases with generation on the 500kV network (including the 220kV side of the Hazelwood 500/220 kV transformers). This typically happens early in the morning. Forecasts are used to determine which configuration will provide the most efficient dispatch for the day.

Appendix C Inter-regional settlement residues

Inter-regional settlements residues (IRSR) arise when electricity is generated in a low priced region and transmitted to a higher priced region. These IRSR are effectively a pool of funds that eligible persons can access via the settlement residue auctions (SRA) process. The SRAs give participants access to IRSR by enabling them to bid for units (shares in the total IRSR amount). The auction process is intended to encourage inter-regional trade by reducing the price difference risks and lead to a more efficient and competitive national electricity market. The firmness of this hedge is, however, affected by the capability of an interconnector—if its capability is reduced when prices diverge, then the benefit of the hedge is significantly discounted.

The settlement residues totalled $141 million for the 2003–04 financial year with the majority accruing for imports into NSW across QNI and the Victoria to Snowy interconnectors. [6]

Indicative results, calculated from the market systems, identify that around two-thirds of the inter-regional settlement residues for the year accumulated on 10 days. An estimate of the residues accruing for those days is presented in figure 1 along with the proportion of the total. For each of these days, however, the interconnector capability was at near nominal limits, which means that the inter-regional settlement residues closely matched those that were anticipated through the SRA process.

Table C1: Top 10 days for accumulation of settlement residues.

Date	Indicative settlement residues		TCC
2/07/2003	$4 million	3%	$918 268
29/07/2003	$5 million	4%	$1 866 010
31/07/2003	$8 million	6%	$598 660
1/09/2003	$4 million	3%	$102 015
7/02/2004	$6 million	5%	$880 402
8/02/2004	$4 million	3%	$1 091 913
13/02/2004	$5 million	3%	$978 020
14/02/2004	$5 million	4%	$533 959
21/02/2004	$6 million	4%	$2 459 118
9/03/2004	$39 million	29%	$9 216 795

6 The settlement residues are significantly higher than the TCC. This is not unexpected. Settlement residues accrue at the rate of the price difference across constrained interconnectors multiplied by the flow. The TCC, however, is the change in generation dispatch from that which occurred with the inter-regional constraint in place. To illustrate this, consider the simple example of flows from Snowy to NSW of 3000MW with prices of $1100/MWh in NSW and $100/MWh in Snowy (and every other region, for simplicity). The settlement residues will accrue at $3 million per hour. The MCC will report $1000 for the constraint that limits the flow. The TCC, however, will dispatch more of the lower priced capacity and less of the $1100/MWh capacity. If the market outcomes were dispatching 10MW offered in NSW at $1100/MWh, then the TCC will dispatch 10MW of $100/MWh capacity and 10MW less of $1100/MWh capacity, leading to an amount of $10 000 per hour.

Appendix D All network constraints

Table D1, sourced from the NECA Reliability Panel 2003–04 annual review, provides a summary of the notice given for all outages by TNSP's to NEMMCO through the NOS. This broad statistic shows that almost one third of all planned outages are submitted with less than four days notice.

Table D1—Transmission outages submitted to NEMMCO

Region	QLD	NSW[1]	VIC	SA	Total
Total outages[2]	1081	1381	1015	556	4033
Scheduled with less than four days notice	34%	20%	35%	35%	29%
Forced outages[3]	7%	8%	11%	13%	9%

[1]The NSW TNSP arranges Snowy outages.

[2]Only primary plant outages (affecting load carrying capability) are included.

[3]Outages not previously notified to NEMMCO, including failures and amendments by TNSPs in response to unforseen extreme conditions.

Appendix E Frequency control ancillary services

The TCC and the MCC have not included the effects of transmission on the Frequency Control Ancillary Service (FCAS) markets. Typically the cost of FCAS is less than 1 per cent of the cost of the energy market and hence does not have a significant impact on the TCC. For the same reasons, constraints associated with the FCAS markets have not been included in the constraints analysed in the MCC. This section provides an assessment of the impacts of transmission on the FCAS markets. The largest impacts on FCAS were as a result of unplanned network events, largely outside of the control of TNSPs.

The total cost of turnover in the FCAS market in 2003–04 was $28 million. There were three days, however, which accounted for around a third of the total, or $9 million. Each of these high cost events coincided with a transmission network event.

On 14 September 2003 the cost of ancillary services totalled around $3 million. This increase resulted from an event that saw the electrical separation of Queensland from the rest of the market for an hour. This followed the loss of a transmission line in NSW during a planned network outage and led to a requirement for local services in Queensland at a cost of $2.7 million. Local raise 6-second prices reached $10 000/MW for almost the entire time.

On 25 November 2003 the cost of ancillary services totalled $700 000. High humidity in north Queensland and the subsequent reclassification of the loss of the two 275 kV feeders between Strathmore and Ross as a single credible contingency led to NEMMCO directing generation. As a result, lower contingency services were sourced locally for two despatch intervals totalling $605 000.

On 8 March 2004 the cost of ancillary services totalled $5.5 million. Most of this resulted from local requirements in SA after the Victoria to South Australia interconnector was lost through bush fires. This led to a need for local services with prices at or close to $10 000/MW.

There were around 145 constraints used to manage the FCAS market. Two of these constraints which are used to manage network outages bound on 33 days and accounted for two per cent of the total, or $570 000.

The F_I+TL_L5_0600 and F_I+TL_L60_0600 constraint sets the requirement for the global lower 5-minute and lower 60-second contingency services when the largest credible loss of load is 600 MW. They are typically used to manage the impacts of network outages in western Victoria which place the Portland smelter on a single contingency. These constraints bound on 33 days during the period for a total of 278 hours. It is estimated that these outages led to an additional FCAS cost of around $570 000.

Appendix F Directions

The TCC and the MCC values the cost of producing electricity using the offer prices of each generator. Generators which are ‘constrained on’ or ‘constrained off’, however, may not have an incentive to offer their output at a price which reflects their own costs. Instead, such generators will, on occasion, offer their output at the price ceiling ($10 000/MWh) or the price floor ($–1000/MWh) of the market. As a result, this can distort the calculation of the TCC or the MCC. This can occur when a generator is directed. To prevent distortions to the TCC, generators offers have been substituted with $300/MWh. This may not necessarily reflect the true cost of the directions. The compensation costs paid to the directed generator are presented below.

There were 10 directions issued by NEMMCO to manage power system security as a result of transmission network issues.

NEMMCO directed a generator on eight occasions throughout the year to manage network loading in North Queensland. The compensation paid for those directions totalled around $4 million. The circumstances of those directions were:

- 17 September 2003 after loss of transmission equipment affecting transfer capability from central to north Queensland
- twice on 24 November 2003 and again on 25 November 2003 as a result of high humidity and multiple transmission line trips in north Queensland
- 5 December 2003 as a result of high humidity and multiple transmission line trips in north Queensland
- 29 December 2003 as a result of high humidity and multiple transmission line trips in north Queensland
- twice on 9 January 2004 following loss of transmission equipment affecting transfer capability from central to north Queensland.

A further two directions were issued in SA following the loss of the Heywood interconnector and electrical separation of SA from the rest of the market on 8 March. The directions were issued to help with frequency control. The compensation paid for those directions was around $1 million.

Appendix G All significant network constraints

The following tables present the most significant constraints for the year. The constraints are grouped according to interconnectors, region, frequency control, grid support and direction. Constraints applied to interconnectors are separated into the direction of flow and the network configuration they model (nominal or inherent capability, and those used to manage network outages).

A1. New South Wales to Queensland

A2 Queensland to New South Wales

A3. Snowy to New South Wales

A4. New South Wales to Snowy

A5. Victoria to Snowy

A6. Snowy to Victoria

A7. Victoria to South Australia

A8. South Australia to Victoria

A9. Queensland intra-regional constraints

A10. New South Wales intra-regional constraints

A11 Snowy intra-regional constraints

A12. Victoria intra-regional constraints

A13 South Australia intra-regional constraints

A14. Constraints setting requirements for Frequency Control Ancillary Services

A15. Constraints used for grid support

A16. Constraints used in power system directions

A1. NEW SOUTH WALES TO QUEENSLAND (QNI) INTERCONNECTOR

Constraints modelling nominal transmission conditions

CONSTRAINT ID	HOURS	CMV ($)	AVG MV	DESCRIPTION
CHI_Q_TR_Q	1	11,300	1,027	CHIMERA constraint (constraint help in managing emergency response action) dynamic limit on flows along QNI north into Queensland.
N^Q_NIL_B	3	10,639	273	System normal, avoid voltage collapse on loss of largest Queensland generator. Dynamic limit across QNI and DirectLink on flows north into Queensland.

Constraints modelling transmission outages

CONSTRAINT ID	HOURS	CMV ($)	AVG MV	DESCRIPTION
N>Q-965_A	4	4,619	103	Outage of 965 line between Armidale and Kempsey, avoid overload of 963 line between Tomago and Taree, for trip of 96F line between Kurri and Stroud.

A2. QUEENSLAND TO NEW SOUTH WALES (QNI) INTERCONNECTOR

Constraints modelling nominal transmission conditions

CONSTRAINT ID	HOURS	CMV ($)	AVG MV	DESCRIPTION
QN_950	173	71,436	35	Physical limit on flows from Queensland to New South Wales of 950 MW.
Q:N_NIL_A	113	64,853	48	System normal, oscillatory stability for the loss of either lines 8C or 8E between Armidale and Dumaresq with high Queensland demand.
Q>N-NIL_DF	28	26,536	80	System normal, limit on southern flows from Queensland to NSW across both QNI and DirectLink. Avoid overload of line 965 between Armidale and Kempsey for trip of 9W3 line between Coffs and Nambucca.
Q>N-NIL_1T	2	12,288	559	System normal, limit flows on 82 line between Liddell and Tomago. Constrains both QNI and DirectLink south into NSW.
Q:N_BI_POT	81	5,495	6	System normal, limit flows across QNI south to avoid transient instability on trip of Boyne Island potline.
Q>N-NIL_DY	2	2,217	117	System normal, limit flows across QNI and DirectLink south to avoid overload of line 965 between Armidale and Kempsey on conditional 5-minute ratings.
Q>N-NIL_DX	10	1,335	12	System normal, limit flows across QNI and DirectLink south to avoid overload of line 965 between Armidale and Kempsey on conditional 5-minute ratings.
QN_350	27	916	3	Discretionary limit on southern flows from Queensland to New South Wales of 350 MW across QNI.
QN_650	2	510	18	Discretionary limit on southern flows from Queensland to New South Wales of 650 MW across QNI.
QNS_0300	2	381	17	Discretionary limit on southern flows from Queensland to New South Wales of 300 MW across QNI and DirectLink.
QNS_0500	5	338	6	Discretionary limit on southern flows from Queensland to New South Wales of 500 MW across QNI and DirectLink.

Constraints modelling transmission outages

CONSTRAINT ID	HOURS	CMV ($)	AVG MV	DESCRIPTION
Q:N_BK_VC_POD_A	13	8,575	55	Outage of Blackwall SVC (or reduction in capability), maintain oscillatory stability for loss of either 8C or 9E lines between Armidale and Dumaresq with high Queensland demand.
N>Q_AR_TX	14	5,680	35	Outage of one of three Armidale 330/132 kV transformers, avoid overload the remaining transformer for trip of the second. Limits flow north across QNI and flow south across DirectLink.
Q:N_BR_VC_A	4	1,534	30	Outage of Braemar SVC, maintain oscillatory stability for the loss of either 8C or 8E lines between Armidale and Dumaresq and high Queensland demand.
Q>N-96H_01	10	1,250	11	Outage of 96H line between Coffs Harbour and Koolkan, limit flows across QNI and DirectLink south, to avoid overload of 965 line between Armidale and Kempsey.
Q>N-9W2_A	13	1,063	7	Outage of 9W2 line between Kempsey and Nambucca, avoid overload of Armidale and Kempsey with 15 minute ratings for trip of 96F line between Kurri and Stroud.
Q:N_BK_VC_A	1	787	56	Outage of Blackwall SVC, maintain oscillatory stability for the loss of either 8C or 8E lines between Armidale to Dumaresq and high Queensland demand.

A3. SNOWY TO NEW SOUTH WALES INTERCONNECTOR

Constraints modelling nominal transmission conditions

CONSTRAINT ID	HOURS	CMV ($)	AVG MV	DESCRIPTION
HN_3000	1	11,290	753	Maximum limit on northern flows from Snowy to New South Wales of 3000 MW.
H>N-64_E	0.1	8,220	8,220	System normal limit on northern flow from Snowy to New South Wales. The 64 line between Lower Tumut and Upper Tumut out of service (normally out of service), avoid overload of 01 line between Upper Tumut and Canberra for trip of 02 line between Upper Tumut and Yass.
H>>H-64_A	1	2,215	277	System normal limit on northern flow from Snowy to New South Wales. The 64 line between Lower Tumut and Upper Tumut out of service (normally out of service), avoid overloading 65 line between Murray and Upper Tumut on loss of 66 line between Murray and Lower Tumut.
H>>H-64_1	0.3	914	305	System normal limit on northern flow from Snowy to New South Wales. The 64 line between Lower Tumut and Upper Tumut out of service (normally out of service), avoid overloading 65 line between Murray and Upper Tumut for loss of 65 line between Murray and Lower Tumut. 30 minute rating.
H>>H-64_G	0.3	162	54	System normal limit on northern flow from Snowy to New South Wales. The 64 line between Lower Tumut and Upper Tumut out of service (normally out of service), avoid overloading 65 line between Murray and Upper Tumut for nil trip.
H>>H-NIL_A	0.3	60	20	System normal limit on northern flow from Snowy to New South Wales. Limit flows on the 65 line between Murray and Upper Tumut for trip of line 66 between Murray and Lower Tumut.

Constraints modelling transmission outages

CONSTRAINT ID	HOURS	CMV ($)	AVG MV	DESCRIPTION
H>>H-LOTF_A	0	10	5	Limit on flow north from Snowy to New South Wales. Outage of line 02 between Upper Tumut and Yass, 65 line between Murray and Upper Tumut and 64 line between Upper Tumut and Lower Tumut (normally out of service), avoid overload of 66 line between Murray and Lower Tumut on trip of 060 line between Jindera and Wodonga.

A4. NEW SOUTH WALES TO SNOWY INTERCONNECTOR

Constraints modelling nominal transmission conditions

CONSTRAINT ID	HOURS	CMV ($)	AVG MV	DESCRIPTION
H>>H-64_C	10	1,058	9	System normal limit on southern flow from Snowy to New South Wales. The 64 line between Lower Tumut and Upper Tumut out of service (normally out of service), avoid overloading 65 line between Murray and Upper Tumut for loss of 66 line between Murray and Lower Tumut.
H>>H-64_3	0.3	184	61	System normal limit on southern flow from Snowy to New South Wales. The 64 line between Lower Tumut and Upper Tumut out of service (normally out of service), avoid overloading 65 line between Murray and Upper Tumut for trip of line 66 between Murray and Lower Tumut. 30 minute line ratings.
H>>H-64_J	1	109	18	System normal limit on southern flow from Snowy to New South Wales. The 64 line between Lower Tumut and Upper Tumut out of service (normally out of service), avoid see-saw action by constraint H>>H-64_G.
I>D0400-NH	0.4	19	4	Discretionary limit on southern flows from New South Wales to Snowy of 400 MW.
I>D0450-NH	0.2	10	5	Discretionary limit on southern flows from New South Wales to Snowy of 450 MW.
N:H_NIL	1	3	3	System normal limit on southern flows from New South Wales to Snowy to manage transient stability limit.
H>>H-64_K	0.2	1	0.5	System normal limit on southern flows from New South Wales to Snowy. The 64 line between Lower Tumut and Upper Tumut out of service (normally out of service), avoid overloading 66 line between Murray and Lower Tumut.
I>D0500-NH	0.2	1	0.5	Discretionary limit on southern flows from New South Wales to Snowy of 500 MW.

Constraints modelling transmission outages

CONSTRAINT ID	HOURS	CMV ($)	AVG MV	DESCRIPTION
N>>N-LTWG_1	2	266	15	Outage of line 051 between Lower Tumut and Wagga, avoid Yass control scheme operation for trip of 62 330 kV line between Wagga and Jindera and 996 132 kV line between Wagga and Anm.
N:H_MNYS	0.3	7	2	Outage of line 4 or 5 between Marulan and Yass, maintain synchronisation between Bayswater and Liddell for fault of lines 33 or 34 between Bayswater and Liddell.
N>H-02__01	1	7	1	Outage of 02 line between Upper Tumut and Yass, avoid overload of 9 line between Yass and Canberra for trip of 03 line between Yass and Lower Tumut.
N:H_DDMS	1	6	1	Outage of either 66 or 67 line between Dederang and Murray. Limit on flows south from New South Wales to Snowy for transient stability limit.

A5. VICTORIA TO SNOWY INTERCONNECTOR

Constraints modelling nominal transmission conditions

CONSTRAINT ID	HOURS	CMV ($)	AVG MV	DESCRIPTION
Hazelwood to South Morang 500 kV—Thermal	162	439,527	229	System normal, limit Victorian exports on V-SN and MurrayLink to avoid overloading the South Morang 500/330 kV (F2) transformer. Aggregation of constraints VH>V3NIL and VH>V4NIL.
VH>V3NIL	156	355,007	189	System normal, limit Victorian exports on V-SN and MurrayLink to avoid overloading the South Morang 500/330 kV (F2) transformer. Network in radial configuration at Hazelwood.
VH>V4NIL	2	67,976	3,090	System normal, limit Victorian exports on V-SN and MurrayLink to avoid overloading the South Morang 500/330 kV (F2) transformer. Network in parallel configuration at Hazelwood.
Hazelwood to South Morang 500 kV – Transient stability	866	43,932	4	System normal. Limit Victorian exports to maintain transient stability on trip of Hazelwood to South Morang 500 kV line. Aggregation of constraints V:H_NILC_R and V:H_NILB_R.
V:H_NILC_R	682	36,198	4	System normal. Limit Victorian exports for transient instability for loss of Hazelwood to South Morang 500 kV line.
VH_0100	2	20,713	714	Discretionary limit on northern flows from Victoria to Snowy of 100 MW.
VH>V3NIL	2	16,465	610	System normal, limit Victorian exports on V-SN to avoid overloading the South Morang 500/330 kV (F2) transformer. Network in radial configuration at Hazelwood.
VH_0900	8	15,987	170	Discretionary limit on northern flows from Victoria to Snowy of 900 MW.
VH_0600	2	13,748	550	Discretionary limit on northern flows from Victoria to Snowy of 600 MW.
VH_0800	1	9,978	907	Discretionary limit on northern flows from Victoria to Snowy of 800 MW.
V:H_NILB_R	184	7,733	4	System normal. Limit Victorian exports to maintain transient stability on trip of Hazelwood to South Morang 500 kV line.
VH_0050	1	7,405	1,058	Discretionary limit on northern flows from Victoria to Snowy of 50 MW.

VH_0500	3	2,796	76	Discretionary limit on northern flows from Victoria to Snowy of 500 MW.
VH_0150	2	2,717	136	Discretionary limit on northern flows from Victoria to Snowy of 150 MW.
VH_0200	0.3	2,615	872	Discretionary limit on northern flows from Victoria to Snowy of 200 MW.
VH_0700	2	2,466	130	Discretionary limit on northern flows from Victoria to Snowy of 700 MW.

Constraints modelling transmission outages

CONSTRAINT ID	HOURS	CMV ($)	AVG MV	DESCRIPTION
Outage of South Morang 500/220 kV transformers	63	9,447	13	Outage of South Morang 500/220 kV transformers. Limit Victorian exports for transient instability for trip of Hazelwood to South Morang 500 kV line.
V:HSMF2C_R	36	6,479	15	Outage of South Morang 500/220 kV transformers. Limit Victorian exports for transient instability for trip of Hazelwood to South Morang 500 kV line.
V:HSMF2C_P	27	2,969	9	Outage of South Morang 500/220 kV transformers. Limit Victorian exports for transient instability for trip of Hazelwood to South Morang 500 kV line.

A6. SNOWY TO VICTORIA INTERCONNECTOR

Constraints modelling nominal transmission conditions

CONSTRAINT ID	HOURS	CMV ($)	AVG MV	DESCRIPTION
HV_0650	66	8,111	10	Discretionary limit on southern flows from Snowy to Victoria of 650 MW.
HV_0700	13	2,595	17	Discretionary limit on southern flows from Snowy to Victoria of 700 MW.
HV_0800	14	1,772	11	Discretionary limit on southern flows from Snowy to Victoria of 800 MW.
HV_0850	9	1,686	15	Discretionary limit on southern flows from Snowy to Victoria of 850 MW.
H>V_NIL1A	8	1,460	15	System normal. Limit southern flows from Snowy to Victoria and flows from South Australia to Victoria across MurrayLink for trip of Dederang to Murray.
HV_0750	8	1,371	14	Discretionary limit on southern flows from Snowy to Victoria of 750 MW.

Constraints modelling transmission outages

CONSTRAINT ID	HOURS	CMV ($)	AVG MV	DESCRIPTION
HV_V2DDMS	30	5,551	15	Limit southern flows from Snowy to Victoria. Outage of one Dederang to Murray 330 kV line, avoid voltage collapse for trip of remaining Dederang to Murray 330 kV line.
H>V_LTMS_2	19	3,214	14	Limit southern flows from Snowy to Victoria. Outage of 66 line between Murray and Lower Tumut, avoid overload on Murray to Upper Tumut for loss of 051 line between Lower Tumut and Wagga.
HV_V1SMSCP	2	1,447	50	Limit southern flows from Snowy to Victoria. Outage of the South Morang 330 kV capacitor, avoid voltage collapse for trip of the largest Victorian generation unit.

A7. VICTORIA TO SOUTH AUSTRALIA (HEYWOOD) INTERCONNECTOR

Constraints modelling nominal transmission conditions

CONSTRAINT ID	HOURS	CMV ($)	AVG MV	DESCRIPTION
VS_460	1321	423 129	27	460 MW limit on flows into South Australia from Victoria across Heywood interconnector. Reduced from 500 MW in April 2003.
Hazelwood to South Morang 500 kV – Transient stability	866	43,932	4	System normal. Limit Victorian exports to maintain transient stability on trip of Hazelwood to South Morang 500 kV line. Aggregation of constraints V:H_NILC_R and V:H_NILB_R. See Victoria to Snowy records.
VS_250	33	36 528	92	250 MW limit on flows into South Australia from Victoria across Heywood interconnector. Most frequently used when lightning is within 80 km of the interconnector.
V:H_NILC_R	682	36,198	4	System normal. Limit Victorian exports to prevent transient instability on trip of Hazelwood to South Morang 500 kV line.
V:H_NILB_R	184	7,733	4	System normal. Limit Victorian exports to prevent transient instability on trip of Hazelwood to South Morang 500 kV line.

Constraints modelling transmission outages

CONSTRAINT ID	HOURS	CMV ($)	AVG MV	DESCRIPTION
V>S_PATB	15	11 024	63	Outage of Para to Tailem Bend in SA, limit flows from Victoria to South Australia.
South Morang 500/220 kV outage.	70	9 952	30	Outage of South Morang 500/220 kV, limit Victorian exports for transient instability on loss of Hazelwood to South Morang. Aggregation of constraints V:HSMF2C_R, V:HSMF2C_P, V:HSMF2B_P.
V>S_BNSG	102	7 653	6	Outage of Blanche to Snuggery in South Australia, limit flows from Victoria to South Australia. Avoid overload on Kincraig to Keith on trip of South East to Tailem Bend.
V:HSMF2C_R	36	6 474	15	Outage of South Morang 500/220 kV transformers. Limit Victorian exports to manage transient instability for trip of Hazelwood to South Morang 500 kV line.
I:VS-250	55	3 759	6	Discretionary limit on Victoria to South Australia interconnector of 250 MW.
VS_150	14	3 080	19	Discretionary limit on Victoria to South Australia interconnector of 150 MW.
V:HSMF2C_P	27	2 969	9	Outage of South Morang 500/220 kV transformers. Limit Victorian exports for transient instability for trip of Hazelwood to South Morang 500 kV line.
V:S_PPT_1	37	1 405	3	Limit Victoria to South Australia interconnector during reclassification of the loss of Pelican Point power station as a credible contingency.
VS_320	9	1 059	9	Discretionary limit on Victoria to South Australia interconnector of 320 MW.
VS_100	2	1 019	39	Discretionary limit on Victoria to South Australia interconnector of 100 MW.
SA_HYSE2	0.1	987	987	Separation between Heywood and South East. South Australia electrically separated from the rest of the NEM.
V:H2RPC_R	17	944	5	Limit Victorian exports with outage of reactive plant in Victoria metro area.
VS_RAMP250	4	693	16	Ramp rate of change limit on Victoria to South Australia interconnector. Used to ramp down flows from Victoria to South Australia ahead of planned outages.
V:HSMF2B_P	7	509	6	Outage South Morang 500/220 kV transformer. Limit Victorian exports for transient instability for loss of Hazelwood to South Morang 500 kV line.

A8. SOUTH AUSTRALIA TO VICTORIA (HEYWOOD) INTERCONNECTOR

Constraints modelling nominal transmission conditions

CONSTRAINT ID	HOURS	CMV ($)	AVG MV	DESCRIPTION
S>V_NIL	2	2 185	91	System normal. Limit flows from South Australia to Victoria.

Constraints modelling transmission outages

CONSTRAINT ID	HOURS	CMV ($)	AVG MV	DESCRIPTION
S>V_PATB	2	13 970	776	Outage of Para to Tailem Bend in SA, limiting flows from South Australia to Victoria. Avoid overload of Angus Creek to Mannum on trip of remaining Para to Tailem Bend line.
SA_HYSE2	0.1	987	987	Separation between Heywood and South East. South Australia electrically separated from the rest of the NEM.

A9. QUEENSLAND INTRA-REGIONAL CONSTRAINTS

Constraints modelling nominal transmission conditions

CONSTRAINT ID	HOURS	DESCRIPTION
Q>PRE855_871CAL	10	System normal, limit pre-contingent flows on line 871 between Wurdong and Calvale for loss of line 855 between Calvale and Stanwell. Constrains Callide B and C off (1540 MW of installed capacity).
Q>PRE855_871GL_ST	10	System normal, limit pre-contingent flows on line 871 between Wurdong and Calvale for loss of line 855 between Calvale and Stanwell. Constraints Stanwell and Gladstone on (3090 MW of installed capacity).
Q_0419	9	Constrains central Queensland generation to less than 1900 MW above central Queensland load. Constrains generation at Callide B and C, Stanwell, Gladstone, Townsville, Barron Gorge, Barcaldine, Collinsville, Kareeya, Mackay and Mt Stuart (5600 MW of installed capacity).
@Q_GPS>=1000	1	Constrains on generation at Gladstone to more than 1000 MW (around 1680 MW of installed capacity).
CHI_Q_TRNG	1	CHIMERA constraint (constraint help in managing emergency response action) limits generation in central and north Queensland (8600 MW of installed capacity).
Q_0541	1	System normal Tarong limit. Limits around 8500 MW of generation in Queensland to manage Tarong limit.
Q:NIL_CN1	1	System normal, central Queensland to north Queensland transient stability limit for loss of either line 822 between Nebo and Strathmore. Constrains generation in north Queensland (880 MW of installed capacity).
Q>NIL855_871GLD_STN	1	System normal, limit pre-contingent flows on line 871 between Wurdong and Calvale for loss of line 855 between Calvale and Stanwell and post contingency switching of lines 7104 and 7105 between Gladstone south and Callide A. Constrains Gladstone and Stanwell (3090 MW of installed capacity).
Q>NIL855_871CAL	1	System normal, limit pre-contingent flows on line 871 between Wurdong and Calvale for loss of line 855 between Calvale and Stanwell and post contingency switching of lines 7104 and 7105 between Gladstone south and Callide A. Constrains Callide B and C (1540 MW of installed capacity).
@Q_GPS>=900	0.1	Constrains on generation at Gladstone to more than 900 MW (1680 MW of installed capacity).
Q_0415	0.1	Discretionary constraint, limiting central Queensland generation to less than 1700 MW above central Queensland load. Constrains generation at Callide B and C, Stanwell, Gladstone, Townsville, Barron Gorge, Barcaldine, Collinsville, Kareeya, Mackay and Mt Stuart (5600 MW of installed capacity).

Q:CN900	0.1	Discretionary constraint, limiting flows from central Queensland to north Queensland. Constrains on generation in north Queensland (880 MW of installed capacity).
Q:CN930	0.1	Discretionary constraint, limiting flows from central Queensland to north Queensland. Constrains on generation in north Queensland (800 MW of installed capacity).
Q:CN940	0.1	Discretionary constraint, limiting flows from central Queensland to north Queensland. Constrains on generation in north Queensland (880 MW of installed capacity).
Q>NIL_871GLD_STN	0.1	System normal, limit MVA transfers along line 871. Constrains on Gladstone and Stanwell power stations (3090 MW of installed capacity) to above 1200 MW.

Constraints modelling transmission outages

CONSTRAINT ID	HOURS	DESCRIPTION
Q>GD_BT_XFMR	17	Outage of H7/T5 Bus Tie Transformer. Constrains on generation at Gladstone 3 and 4 to greater than 450 MW.
Q_GLD1200	12	Constrains Gladstone (1680 MW of installed capacity) to generate at levels greater than 1200 MW.
Q:RS_225	6	Outage of line 879 or line 880 between Strathmore and Ross, limit flows south from Ross to below 225 MW to manage transient instability for 2 phase to ground fault. Used during the year for reclassifications of the loss of both lines as credible contingency.
Q^CN_7150_H11NE_VC	1	Outage of line 7150 between Lilyvale and Dysart and Nebo SVC. Thermal limit between north Queensland and central Queensland. Constrains on generation in north Queensland to manage voltage stability.
Q>7150_CN_900	0.1	Outage of line 7150 between Lilyvale and Dysart. Thermal limit between north Queensland and central Queensland. Constrains on generation in north Queensland.

A10. NEW SOUTH WALES INTRA-REGIONAL CONSTRAINTS

Constraints modelling nominal transmission conditions

CONSTRAINT ID	HOURS	DESCRIPTION
N>N-NIL_1T	3	System normal, avoid overload of 82 line between Liddell and Tomago. Affects at least 11 520 MW of installed capacity.
N>N-NIL_28	1	System normal, avoid overload of 8 line between Marulan to Dapto for trip of 16 line between Marulan and Avon. Affects around 7200 MW of installed capacity.
N>N-NIL_1G	0.1	System normal, avoid overload of 23 line between Vales Point and Munmorah for trip of 22 line between Vales Point and Sydney North. Affects more than 11 500 MW of installed capacity.
N>N-NIL_1A	0.1	System normal, avoid overload on 33 or 34 line between Bayswater and Liddell for trip of the other. Affects more than 11 500 MW of installed capacity.
N>N-NIL_04	0.1	System normal avoid overload on 4 line between Marulan and Yass for trip of 5 line between Marulan and Yass. Affects more than 11 700 MW of installed capacity.

Constraints modelling transmission outages

CONSTRAINT ID	HOURS	DESCRIPTION
N>N-81__19	29	Outage of 81 line between Liddell and Newcastle, avoid overload of 82 line between Liddell and Tomago on trip of 32 line between Bayswater and Sydney West. Affects around 10 000 MW of installed capacity.
N>N-22__03	10	Outage of 22 line between Vales Point to Sydney North, avoid over load of 23 line between Vales Point and Munmorah on trip of 25 line between Eraring and Vineyard. Affects around 11 500 MW of installed capacity.
N>N-22__04	2	Outage of 22 line between Vales Point to Sydney North, avoid over load of 23 line between Vales Point and Munmorah on trip of 32 line between Bayswater and Sydney West. Affects around 11 700 MW of installed capacity.
N>N-82__15	1	Outage of 82 line between Liddell and Tomago, avoid overload of 81 line between Liddell and Newcastle on trip of 32 line between Bayswater and Sydney West. Affects around 11 500 MW of installed capacity.
N>N-22__01	1	Outage of 22 line between Vales Point and Sydney North, avoid overload on 23 line between Vales Point and Munmorah on trip of 14 line between Sydney North and Kemps Creek. Affects around 11 500 MW of installed capacity.
N>N-81__22	1	Outage of 81 line between Liddell and Newcastle, avoid overload of 82 line between Liddell and Tomago on trip of 31 line between Bayswater and Regentville. Affects around 11 500 MW of installed capacity.
N>N-82__14	0.1	Outage of 82 line between Liddell and Tomago, avoid overload of 81 line between Liddell and Newcastle on trip of 31 line between Bayswater and Regentville. Affects around 11 500 MW of installed capacity.
N>N-81__27	0.1	Outage of 81 line between Liddell and Newcastle, avoid overload of 82 line between Liddell and Tomago. Affects around 11 500 MW of installed capacity.
N>N-32__01	0.1	Outage of 32 line between Bayswater and Sydney West, avoid overload of 23 line between Vales Point and Munmorah on trip of 22 line between Vales Point and Sydney North. Affects around 9000 MW of installed capacity.
N>N-5___03	0.1	Outage of 5 line between Marulan and Yass, avoid overload of 4 line between Marulan and Yass for trip of 6 line between Canberra and Kangaroo Creek. Affects around 11 760 MW of installed capacity.

A11. SNOWY INTRA-REGIONAL CONSTRAINTS

Constraints modelling nominal transmission conditions

CONSTRAINT ID	HOURS	DESCRIPTION
#UPPTUMUT_E	18	Limits dispatch at Upper Tumut (600 MW of installed capacity).
#TUMUT3_E	13	Limits dispatch at Lower Tumut (1500 MW of installed capacity).
#MURRAY_E	3	Limits dispatch at Murray (1500 MW of installed capacity).
H_ULT_0550	0.4	Limits dispatch at Upper Tumut and Lower Tumut (2100 MW of installed capacity) to a maximum of 550 MW.
H>H-64__05	0.2	64 line out of service (normally out of service), increase Upper Tumut and Lower Tumut generation (2100 MW of installed capacity) to avoid overload of Murray to Lower Tumut on Murray to Upper Tumut trip.

Constraints modelling transmission outages

CONSTRAINT ID	HOURS	DESCRIPTION
H>H-060_S1	0.1	Outage of 60 line between Jindera an Wodonga, reduce Upper Tumut and Lower Tumut to avoid overload of 65 line between Upper Tumut to Murray on trip of 66 line between Lower Tumut and Murray.

A12. VICTORIA INTRA-REGIONAL CONSTRAINTS

Constraints modelling nominal transmission conditions

CONSTRAINT ID	HOURS	DESCRIPTION
Hazelwood transformer	163	Hazelwood transformer constraint. Yallourn unit 1 switched to either 220 kV or 500 kV network. Affects generation at Morwell, Bairnsdale, Hazelwood, Jeeralang A and B and Yallourn unit 1. Aggregation of constraints V>V1NIL and V>V2NIL.
V>V1NIL	121	Hazelwood transformer constraint. Yallourn unit 1 switched to 500 kV network. Affects generation at Morwell, Bairnsdale, Hazelwood, Jeeralang A and B and Yallourn unit 1, around 2079 MW of installed capacity.
V>V2NIL	43	Hazelwood transformer constraint. Yallourn unit 1 switched to 220 kV network. Affects generation at Morwell, Bairnsdale, Hazelwood and Jeeralang A and B, around 1719 MW of installed capacity.

Constraints modelling transmission outages

CONSTRAINT ID	HOURS	DESCRIPTION
@JLG_MW_BDL_HZ	6	Constrains Jeeralang, Morwell, Bairnsdale and Hazelwood around 1120 MW of installed capacity to a maximum of 890 MW.
V>JLG_185	1	Constrains Jeeralang B, around 228 MW of installed capacity to a maximum of 185 MW.
V>V10NIL	1	Outage of Mt Beauty 220 kV Bus tie CB, limit Southern Hydro generation (around 500 MW of installed capacity) to avoid overloading of Dederang to Mt Beauty No.2 220 kV line for loss of Dederang to Mt Beauty No.1 220 kV line.
V>EPTT	1	Outage of Eildon to Thomastown 220 kV line, limit Southern Hydro generation (around 500 MW of installed capacity) to avoid overloading either Dederang to Mt Beauty 220 kV line for trip of one the lines.
@_SHYDR=298	1	Constrains Southern Hydro generation (around 500 MW of installed capacity) to a maximum of 298 MW.
@HW12678ETC	0.1	Constrains Jeeralang, Morwell, Bairnsdale and Hazelwood generation (around 1719 MW of installed capacity) to less than 1450 MW.
V>D4500-LV	0.1	Constrains generation in the Latrobe Valley at Loy Yang A and B, Morwell, Valley Power, Bairnsdale, Hazelwood, Jeeralang A and B and Yallourn (around 7700 MW of installed capacity) to a maximum of 4500 MW.
V>D4750-LV	0.1	Constrains generation in the Latrobe Valley at Loy Yang A and B, Morwell, Valley Power, Bairnsdale, Hazelwood, Jeeralang A and B and Yallourn (around 7700 MW of installed capacity) to a maximum of 4750 MW.

A13. SOUTH AUSTRALIA INTRA-REGIONAL CONSTRAINTS

Constraints modelling nominal transmission conditions

Nil

Constraints modelling transmission outages

CONSTRAINT ID	HOURS	DESCRIPTION
S:PPT_720-VS	17	Limits Pelican Point dispatch to less than 720 less transfers from Victoria to South Australia across Heywood interconnector. Pelican Point reclassified as single contingency. Not a transmission constraint.
S^PPT340	7	Limit Pelican Point (480 MW of installed capacity) to a minimum of 340 MW.
@SA_22APRIL04	4	Limits dispatch of Northern and Playford (around 800 MW of installed capacity) to less than 475 MW.
@SPLN=5	3	Sets Port Lincoln dispatch to 5 MW.
S^PPT330	0.1	Limit Pelican Point dispatch to greater than 330 MW.

A14. CONSTRAINTS SETTING REQUIREMENTS FOR FREQUENCY CONTROL ANCILLARY SERVICES

Constraints modelling nominal transmission conditions

CONSTRAINT ID	HOURS	CMV ($)	AVG MV	DESCRIPTION
F_I+NIL_MG_R6	8,696	249,354	2	System normal, Raise 6 second mainland requirement for the loss of the largest generating unit.
Raise regulation	8,693	153,264	1	Mainland raise regulation.
Lower regulation	7,234	138,614	2	Mainland lower regulation.
F_I+NIL_MG_R5	8,615	113,362	1	System normal, Raise 5 minute mainland requirement for the loss of the largest generating unit.
F_I+NIL_MG_R60	8,684	78,875	1	System normal, Raise 60 second mainland requirement for the loss of the largest generating unit.
F_I+RREG_0180	3,600	60,058	1	System normal, mainland raise regulation requirement of 180 MW.
F_I+LREG_0180	3,600	57,560	1	System normal, mainland lower regulation requirement of 180 MW.
F_I+LREG_0220	2,190	50,568	2	System normal, mainland lower regulation requirement of 220 MW.
F_I+RREG_0220	2,189	45,155	2	System normal, mainland raise regulation requirement of 220 MW.
F_I+MLOAD_L5_0370	8,234	31,717	0	System normal, mainland lower 5 minute service for load event with maximum load set at 370 MW.
F_I+LREG_0200	1,444	30,486	2	System normal, mainland lower regulation requirement of 200 MW.
F_I+RREG_0200	1,444	26,850	2	System normal, mainland raise regulation requirement of 200 MW.
F_I+RREG_0160	1,460	21,202	1	System normal, mainland raise regulation requirement of 160 MW.

Constraints modelling transmission outages

CONSTRAINT ID	HOURS	CMV ($)	AVG MV	DESCRIPTION
F_SA_LG+MG_R5	0.4	69,543	13,909	Outage of line between Para and South East, islanding South Australia. Raise 5 minute requirement in SA for loss of largest generating unit. Ladbroke connected to Victoria.
F_SA_ISLE+RREG_0100	0.4	56,999	11,400	South Australia islanded, raise regulation requirement in South Australia of 100 MW.
F_SA_ISLE_L60_0100	0.4	50,000	10,000	South Australia islanded, lower 60 second requirement for South Australia load event with maximum load set at 100 MW.
F_SA_ISLE_L6_0100	0.4	50,000	10,000	South Australia islanded, lower 6 second requirement for South Australia load event with maximum load set at 100 MW.
F_SA_LG+MG_R6	0.4	50,000	10,000	Outage of line between Para and South East, islanding South Australia. Raise 6 second requirement in SA for loss of largest generating unit. Ladbroke connected to Victoria.
F_SA_LG+MG_R60	0.4	50,000	10,000	Outage of line between Para and South East, islanding South Australia. Raise 60 second requirement in SA for loss of largest generating unit. Ladbroke connected to Victoria.
F_SA_ISLE+LREG_0100	0.4	39,558	7,912	South Australia islanded, lower regulation requirement in South Australia of 100 MW.
F_SA_ISLE_L5_0100	0.3	30,000	10,000	South Australia islanded, lower 5 minute requirement for South Australia load event with maximum load set at 100 MW.
F_I+TL_L5_0600	278	19,196	6	Mainland lower 5 minute requirement for transmission event leading to loss of 600 MW of load.

A15. Constraints used for grid support

CONSTRAINT ID	HOURS	DESCRIPTION
Q:CN1QMSP2	120	Has the effect of constraining on Mt Stuart unit 2.
Q:CN1QMSP1	41	Has the effect of constraining on Mt Stuart unit 1.
#POR01_E	12	Has the effect of constraining on Port Lincoln.
#MSTUART2_E	12	Has the effect of constraining on Mt Stuart unit 2.
Q_CN_QCVL_*	8	Has the effect of constraining on Collinsville
S>MTSE_1SG	4	Outage between Mount Gambier and South East of South Australia, Avoid O/L 132 kV KH-SG by Snuggery Generation, Transmission support agreement (TSA).
#YABULU_E	4	Has the effect of constraining on Yabulu.
#BDL01_E	1	Has the effect of constraining on Bairnsdale. Distribution grid support arrangement by SP AusNet.

A16. Constraints used in power system directions

CONSTRAINT ID	HOURS	DESCRIPTION
#MSTUART2_E	1	Has the effect of constraining on Mt Stuart unit 2.
#YABULU_E	1	Has the effect of constraining on Yabulu.
#MSTUART1_E	1	Has the effect of constraining on Mt Stuart unit 1.