Indicators of the market impact of transmission congestion

Decision

9 June 2006

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Foreword

The role of the Australian Energy Regulator

The Australian Energy Regulator (AER) is responsible for regulating the revenues of transmission network service providers (TNSPs) in the National Electricity Market (NEM). The AER sets revenue targets based on forecast costs and provides TNSPs with incentives to reduce expenditures below forecasts. The incentives to cut costs are balanced against the TNSPs' statutory obligations and the service standards incentives prescribed in revenue determinations. The incentive regime was designed to provide investment certainty for the TNSPs, promote efficient investment in transmission networks and achieve efficient operation of the networks.

The AER considers that an incentive-based regime requires the regulator to balance cost-cutting incentives against service standards requirements. There is no intrinsically 'right' answer to this balancing act and regulators need to adjust their incentive schemes as they learn from experience.

Current arrangements

At present, the AER has a performance incentive scheme which has been applied in seven transmission revenue cap decisions. This performance incentive scheme is based on the AER's service standards guidelines, which forms part of its compendium of regulatory principles.

This performance incentive scheme is aimed at deterring TNSPs from cutting costs that would reduce service standards. Under a revenue cap TNSPs receive a fixed revenue stream and the way to maximise profit is to minimise costs. This approach to maximising profit can result in reducing costs at the expense of service standards.

The current performance incentive scheme gives TNSPs an incentive to increase service standards to increase their revenue caps. This means the performance incentive scheme makes it less profitable for TNSPs if reducing their costs leads to a reduction in service standards.

To date the incentive has been limited to one per cent of each TNSP's revenue cap, which reflects the relatively early stage of development of the service standards incentive scheme. However, there is flexibility under the current arrangements for the incentive to be altered as the scheme is further developed.

There has been some concern that TNSPs are not sufficiently accountable for the costs born by the wider market of transmission congestion and that an incentive/penalty regime should be imposed on TNSPs to promote more efficient behaviour.

This decision

This decision results from significant work started by the Australian Competition and Consumer Commission (ACCC) and then progressed by the AER. In undertaking this work the AER has been assisted by input from many stakeholders.

The primary objective of this decision is to publish information to improve understanding about transmission congestion. The reported indicators proposed in this decision will:

- identify the causes and market impacts of transmission constraints
- provide information to participants that can be used as a tool to guide behavioural decisions and promote more efficient market participant behaviour
- be used as a tool to develop improved service standards incentives.

Data on each of the indicators for 2003–04 has been released in conjunction with this decision. Results for 2004–05 and 2005–06 will be released in the third quarter of this year.

Caution should be exercised in drawing conclusions from a single year's data. The AER considers that reliable conclusions may be reached as more data is published and stakeholders provide feedback. The key to this information is to monitor the change through time.

The AER's intention is to use this data as a reference to the development of a market-based service standards incentive scheme for TNSPs. Extensive work has already been undertaken in consultation with the industry to develop the indicators of market impacts included in this decision. In time, the AER considers that financial incentives can be developed based on these indicators. It is important that all market-based measures are robust otherwise the introduction of an incentive may have an unintended impact.

Feedback

I hope that this decision and accompanying report will provide interested parties with information to enable critical evaluation of the market impact of transmission congestion. I encourage you to read this decision and provide feedback to the AER.

Steve Edwell
Chairman

Contents

Glossary

AC	alternating current
ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
compendium of regulatory guidelines	*Compendium of electricity transmission regulatory guidelines,* AER, August 2005
ERAA	Energy Retailers’ Association of Australia
EUAA	Energy Users’ Association of Australia
IES	Intelligent Energy Systems
LP	linear program
MCC	marginal cost of constraints
MCE	Ministerial Council on Energy
MW	megawatt
NECA	National Electricity Code Administrator
NEM	National Electricity Market
NEMDE	National Electricity Market dispatch engine
NEMMCO	National Electricity Market Management Company
NGF	National Generators’ Forum
OCC	outage constraint cost
PCC	partial constraint cost
RHS	right-hand side
rules	National Electricity Rules
service standards guidelines	*Statement of principles for the regulation of transmission revenues—service standards guidelines,* ACCC, Nov. 2003
SRP	*Statement of principles for the regulation of electricity transmission revenues,* ACCC, December 2004
TCC	total cost of constraints
TNSP	transmission network service provider
VoLL	value of lost load

Summary

Improving transmission service standards

In 2003 the Australian Competition and Consumer Commission (ACCC) released its *Statement of principles for the regulation of transmission revenues—service standards guidelines* [1] (service standards guidelines), and in 2005 the Australian Energy Regulator (AER) adopted the service standards guidelines as part of its compendium of regulatory guidelines. The service standards guidelines outline the AER's approach to setting service standards incentives within the revenue cap framework set out in the National Electricity Law (the NEL) and National Electricity Rules (the rules).

The service standards guidelines link regulated revenues to the transmission network service providers' (TNSPs) performance against defined performance measures:

- transmission circuit availability
- average outage duration
- frequency of 'off supply' events.

The service standards guidelines provide incentives for TNSPs to improve performance against these measures by rewarding them when performance standards increase, and penalising them when performance standards decline. The rewards and penalties are capped at plus or minus one per cent of annual regulated revenues.

The existing incentive regime focuses on outages. This is a useful starting point but also has some limitations. One limitation is that many outages do not matter. Virtually none cause blackouts, and even if they do it is in conjunction with other events. Similarly most outages do not force the National Electricity Market Management Company (NEMMCO) to dispatch more expensive generation, so they do not have an effect on price outcomes in the wholesale market. To this extent the transmission network is the backbone of the electricity system and it is important to have indicators that measure the costs to the market of transmission constraints and if possible an enhanced incentive regime to promote more efficient operation of the transmission system.

Accordingly, the AER aims to improve transmission service standard outcomes by addressing the limitations of the current service standards incentive scheme. More specifically the AER's objective is to link service standards incentives more directly to market outcomes.

As a first step this decision provides for collection and publication of new data on the market impact of transmission congestion. As a second step, the AER will assess

[1] *Decision: Statement of principles for the regulation of transmission revenues—service standards guidelines*, ACCC, 12 November 2003.

options for improving service standards incentives. It intends to undertake public consultation on this issue in early 2007.

This decision follows an extensive consultation process. In 2004 the ACCC released a draft decision and received 10 submissions from interested parties. The AER subsequently worked closely with an industry working group comprising TNSP, retailer, generator and user representatives and established a working group with NEMMCO to work through implementation issues.

Indicators of transmission congestion

Transmission networks transport electricity from generators to consumers. The flow of electricity is at times limited by the capacity of transmission elements such as lines and transformers. The flows can also be limited by 'outages' due to equipment failure and maintenance work, and by a range of other factors such as generation patterns, demand patterns, weather conditions, the setting of network security standards and the management of security standards by NEMMCO.

Major transmission outages together with other coincident generation or demand events could cause users to be blacked out, but in the National Electricity Market (NEM) transmission induced blackouts are extremely rare. Instead the main impact of congestion is on generation dispatch. The output of low-cost generators can be limited by transmission constraints between the generator and consumers, forcing higher cost generators to supply electricity in their place. The market impact of congestion is the cost to the market of having higher cost generation dispatched when lower cost generation is available.

The AER has adopted several indicators of the cost of transmission congestion in this decision:

- the total cost of constraints (TCC)
- the outage constraint cost (OCC)
- the marginal cost of constraints (MCC)
- a qualitative assessment of the indicators.

The TCC estimates the benefit to the market when all transmission constraints are removed. It does this by modelling the cost of generation that would have resulted without any transmission constraints and comparing it to the actual cost of generation. The difference is the TCC.

The modelling is based on the generators' actual (historic) bids. Generators lodge bids with NEMMCO for every five-minute period in the day. NEMMCO uses the bids to determine which generators are dispatched and at what level of output. Subject to transmission and other constraints, NEMMCO dispatches generation on the basis of bid price in ascending order until demand is met. In the modelling, the dispatch price for each bid is multiplied by the quantity dispatched at that price, then summed to give a total cost of dispatch. The TCC is the difference between the cost of dispatch with and without constraints.

More congestion in the transmission network is typically associated with a higher TCC. Some constraints also have a greater effect on market outcomes than others. For example, the impact on the TCC may be substantial if cheap coal-fired generation is ‘constrained off’ and replaced by a high-cost peaking plant. By contrast congestion which ‘constrains off’ one coal-fired plant and requires the dispatch of another coal-fired plant may have little impact.

The OCC is similar to the TCC but only estimates the benefit to the market from removing all transmission **outage** constraints (and retaining other causes of congestion such as ‘system normal’ capacity limits). The AER has included this indicator because retailers, generators and other traders are particularly interested in the TNSPs’ management of outages. If the impacts of the outages are not predictable or notified well in advance then it can be difficult for traders to manage the associated risks.

The third indicator, the MCC, estimates the benefit to the market from relieving a transmission constraint at the margin. It does this by modelling how much the cost of generation would be reduced if the transmission limit was relieved by one megawatt. The MCC is useful in helping to identify the elements of the transmission network that are the primary contributors to the TCC.

The three indicators will be supplemented by a qualitative assessment. The assessment will identify major congestion events and explain their causes. The qualitative assessment will allow the market to understand how transmission constraints affect the market.

Data on each of the indicators for 2003–04 has been released in conjunction with this decision. Results for 2004–05 and 2005–06 will be released in the third quarter of this year.

In the fourth quarter of this year the AER will start publishing the market impact indicators on a weekly basis as part of its weekly market reports. The AER will also publish a summary of outcomes as part of its annual state of energy markets report. The first state of the markets report will be released in the fourth quarter of 2006.

In addition to the AER’s qualitative assessment, TNSPs have agreed to report on the nature of transmission constraints. This will provide an overview of the type of constraints that occurred over the period for each network. The AER will make the TNSPs’ reports publicly available. TNSPs have advised that these reports will be published starting with data from 2004–05.

Details of the decision are set out in chapter 1.

Submissions and issues

The submissions on the draft decision[2] and the working group identified three main issues:

- how grid support should be treated in the TCC
- consistency of the indicators with the regulatory test as promulgated under clause 5.6.5A of the rules
- development of alternative indicators.

Collectively the TNSPs argued that the draft TCC measure included an incorrectly high cost for constraints managed by grid support agreements. Capacity in some areas of the transmission network is inadequate to meet high levels of demand that occur for relatively short periods. In some circumstances TNSPs enter into grid support contracts with generators to supply electricity. Grid support agreements can be a cost-effective alternative to expensive transmission augmentation.

The problem identified by the TNSPs is that generators bid into the market even if they are being dispatched under a grid support agreement. When the grid support agreement is triggered the real cost to the market is the price struck under the grid support contract. If the generators' bidding in the market is also included in the TCC calculation, the result is a double count.

The AER agrees that the TCC model in the draft decision overstates costs associated with constraints where grid support is used, and has removed the effect of those constraints in the published TCC.

Some submissions argued that the TCC should be consistent with the principle of 'competition benefits' under the regulatory test. The AER considers that the TCC is consistent with those principles. However there are some differences between the TCC and competition benefits under the regulatory test:

- The TCC is an indicator that looks backward, whereas the regulatory test requires a forward-looking assessment of the effect of transmission investment.
- The TCC estimates the effect of all transmission constraints. By contrast the regulatory test considers options that would reduce or remove a single or small group of constraints.
- The TCC is based on actual bids, whereas the regulatory test (including the competition benefits test) is based on estimated generation costs.
- The TCC data will cover relatively short time periods (at least initially) so may include significant amounts of stochastic noise due, for example, to weather

[2] *Draft decision: Statement of principles for the regulation of transmission revenue, market impact transparency measures*, ACCC, 28 July 2004.

events. In turn this may result in significant short-term variability in results. By contrast the regulatory test is applied over the life of the asset. The longer time frames in the regulatory test average out this variability.

These differences mean that the TCC should not be seen as a substitute for the regulatory test. Rather, they perform different roles.

Several submissions argued in favour of alternative indicators which are more closely aligned to TNSP actions than the TCC or MCC. The ERAA and NGF proposed a partial constraint cost (PCC) indicator which compares actual constraint costs with a base line based on factors that the TNSPs could address. Powerlink and Electranet went one step further and defined the base line as system normal conditions, that is, the constraints when there are no outages. This approach is described as the OCC.

The AER has decided to publish the OCC. It considers that the OCC will provide a useful supplement to the TCC by providing additional information about the TNSPs' contribution to transmission congestion.

A full discussion of the issues is provided in chapter 2.

Economic incentives

The NEL and the rules require the AER to implement incentive-based regulation. The AER’s approach is set out in its *Statement of principles for the regulation of electricity transmission revenues* (SRP). The SRP also forms the basis for the rules proposed by the AEMC in its review of chapter six of the rules.

The AER sets revenue targets based on forecast costs and provides TNSPs with incentives to reduce expenditures below forecasts. These cost-cutting incentives need to balance against the TNSPs' statutory planning standards obligations[3] and service standards incentives to avoid cost cutting at the expense of service quality.

As discussed above the existing service standards regime has the limitation of focusing on outages which in many cases have no market impact. The AER’s objective is to establish incentives that are more directly linked to end-user benefits and maximise the capability of the transmission system at times that provide most value to end users. The AER intends to draw on information provided by the indicators to develop and consult on a new or revised service standards incentive scheme.

[3] Currently most TNSPs in the NEM (TransGrid, Powerlink and Electranet) have to comply with statutory planning standards set by each of the state governments (such as n-1 requirements). In Victoria planning standards do not apply to SP AusNet, but network augmentation is determined by the independent planning agency, VENCorp. Similarly Tasmania does not currently have planning standards for Transend, but is in the process of establishing them.

After the AEMC releases its final decision on the review of chapter six of the rules, the AER will start consultation in line with the rules. At this stage the AER anticipates beginning the process in early 2007.

The AER will start its consultation process with an options paper. The process will also include a draft decision, providing details of one preferred way forward and/or an amended set of service standard guidelines.

The AER will continue to draw on the expertise and input of the service standards working group.

1 Decision

1.1 Introduction

This is a decision on the publication of information on the market impact of transmission congestion in the National Electricity Market (NEM). There are three elements to the decision:

1. The Australian Energy Regulator (AER) has decided to publish three measures of the market impact of transmission congestion—the total cost of constraints (TCC), the outage cost of constraints (OCC) and the marginal cost of constraints (MCC).

2. The AER has decided to provide analysis of the data, and to make available information on the nature of transmission constraints prepared by the transmission network service providers (TNSPs).

3. The AER will also assess options for improving service standards incentives. It intends to start a public consultation process early in 2007.

The decision relates to all interconnected transmission in the NEM and covers seven network service providers: Directlink, Electranet, Murraylink, Powerlink, Transend, Transgrid and SP AusNet.

Section 1.2 sets out the processes followed by the AER to reach this decision, sections 1.3 through to 1.6 provide information on what transmission congestion is and why it matters. The remainder of the chapter sets out the AER's decision.

1.2 Process

This decision reflects a significant body of work completed by the AER. In undertaking this work the AER has benefited from the considered input of many stakeholders.

In November 2003 the Australian Competition Consumer Commission (ACCC) published its *Statement of principles for the regulation of transmission revenues—–service standards guidelines*[4] (service standards guidelines). The service standards guidelines were adopted by the AER in its *Compendium of electricity transmission regulatory guidelines* (compendium of regulatory guidelines) in August 2005[5]. The service standards guidelines set out the AER's approach to setting service standards within the revenue cap framework set out in the National Electricity Law (the NEL) and the National Electricity Rules (the rules).

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4 *Decision: Statement of principles for the regulation of transmission revenues—service standards guidelines*, ACCC, 12 November 2003.

5 *Compendium of electricity transmission regulatory guidelines*, AER, August 2003.

As part of its consultation process in developing the service standards guidelines, the ACCC identified the market impact of transmission congestion as a significant issue. It recognised that these guidelines do not directly address the market impact of congestion, and committed to undertake further work towards developing market impact indicators.

The ACCC formed the industry-based service standards working group to consider this issue to assist it improve the service standards guidelines. The working group initially convened in December 2003. In total the working group has convened six times, most recently in December 2005. The AER has continued to draw on the working group's input.

The working group members include representatives of consumers, generators, retailers, TNSPs and NEMMCO to provide a cross-section of views and to draw on a broad range of expertise. The ACCC engaged consultants to advise it and the working group.

In July 2004 the ACCC published a draft decision recommending publication of the TCC and MCC and supporting qualitative analysis.[6] In selecting the indicators, the draft decision provided a detailed evaluation of options against specified evaluation criteria.

After releasing the draft decision the AER consulted with NEMMCO to develop a model for calculating the TCC. The AER engaged Intelligent Energy Systems (IES) to conduct an audit of the model. This helped to resolve some outstanding calculation issues. The model will be integrated into NEMMCO's market systems in November 2006.

The final decision to publish indicators of the impact of transmission congestion is consistent with the draft decision. The AER has also decided to publish an additional indicator, the outage constraint cost (OCC)—as a response to submissions and discussions of the service standards working group.

1.3 What is transmission congestion?

Transmission networks are physically limited in the amount of electricity they can transport. Congestion occurs when the flow of electricity reaches the physical limit of the transmission network.

Congestion can be caused by factors within the control of TNSPs such as investment and operating decisions. Congestion can also be driven by factors outside the TNSPs' control such as demand growth, changing patterns of demand and new or discontinued generation. Specific events can also contribute to congestion for example:

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6 *Draft decision: Statement of principles for the regulation of transmission revenue—market impact transparency measures*, ACCC, 28 July 2004.

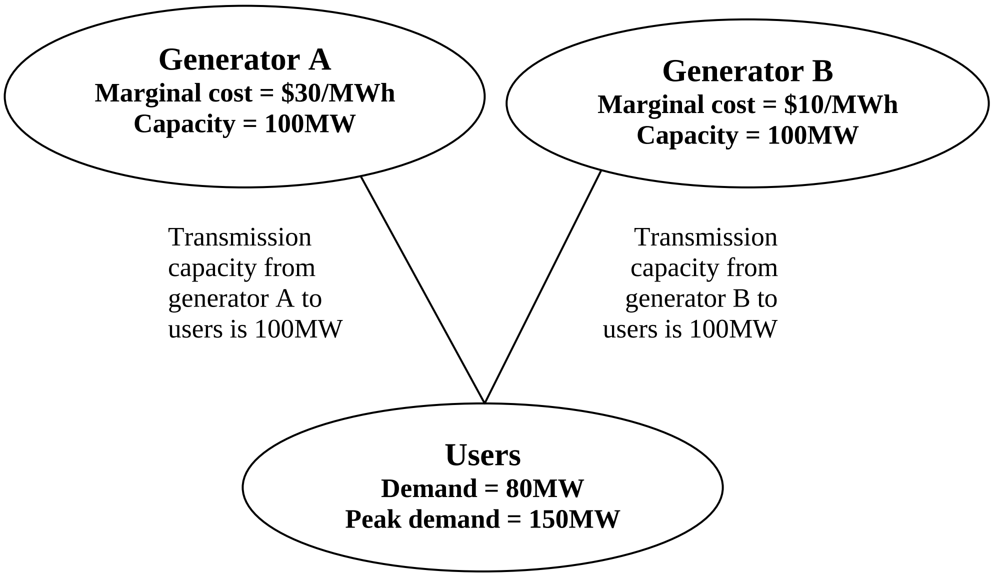
- outages of some elements of the network, which can be due to equipment failure, maintenance work or capital works
- weather events such as lightning
- peak demand events driven by weather or other factors.

1.4 Impacts of congestion

Transmission congestion results in higher cost generators being dispatched to supply electricity. If the congestion is reduced or removed, lower-cost generation will be dispatched. However, reducing transmission congestion is not costless and the costs and benefits need to be weighed up to determine the 'optimal' level of congestion.

Figure 1 and the boxed text below provide a simple worked example of the effect of a transmission constraint on the cost of supplying electricity. The example shows how transmission congestion can be as significant determinant of generation costs in the NEM.

Figure 1 Congestion dispatching higher cost generation



In the NEM generators are dispatched in the order of lowest to highest price offer subject to network capability. In a competitive market these price offers are equal to the marginal cost of the generator. Network constraints can cause two impacts:

1. higher spot prices

2. higher cost of generating electricity to meet demand.

If demand is only 80MW and there are no transmission constraints, generator B offers 100MW for $10/MWh. It is dispatched for 80MW and the price is set at $10/MWh.

However, if a transmission outage results in a limit of 60MW between the users and generator B, then generator A will also be required to be dispatched to meet demand.

In this case generator B is dispatched to 60MW, which is the limit imposed by the outage. Generator A is then dispatched for 20MW to ensure the demand of 80MW is met. This has the effect of setting the spot price at $30/MWh rather than $10/MWh that would have occurred had the outage not imposed the transmission limit of 60MW. The cost of this constraint caused by the outage is $400 ($20*20MW). The marginal impact of this constraint is $20.

There would also be times where a transmission limit does not affect the spot price, but has the effect of increasing the cost to generate the amount of electricity to meet demand.

Using the same example but at times of peak demand (150MW), the transmission network can deliver 200MW in total from generators A and B to users.

Generator B would offer its capacity (100MW) at $10/MWh and it would be dispatched to 100MW. Generator A would offer its capacity (100MW) at $30/MWh. The system operator would dispatch generator A for 50MW, to ensure total demand of 150 MW was met. The spot price is set at $30/MWh.

In the presence of the outage, which limits generation at generator B to 60 MW and requires generator A to be dispatched to 90 MW, the market impact is the same. The constraint requires a further 40MW of electricity supplied at the higher cost of $30/MWh, as opposed to $10/MWh, for the duration of peak demand. The marginal impact of this is $20 and the cost of this constraint caused by the outage is $800 (= $20 x 40MW).

1.5 Eliminating congestion

If transmission congestion never occurred, the lowest cost generators would always be dispatched. However, eliminating all congestion is not likely to be achievable or efficient.

To prevent all congestion, a TNSP would need to exactly forecast all future instances of transmission congestion. Given the nature of this assumption it is easy to see how eliminating all transmission congestion is not readily achievable.

To prevent the biggest market impacts of potential constraints, a TNSP would need to be able to forecast, with some accuracy, major transmission constraints. While this is achievable, it would not be efficient to relieve those constraints if the costs of doing so exceeded the benefits. Each constraint would need to be addressed on a case-by-case basis.

The regulatory test is a tool for making this cost-benefit assessment. It has been established to ensure that a TNSP invests efficiently when undertaking large capital expenditure. Where a TNSP intends to invest a large amount in relieving transmission congestion, it can take ‘competition benefits’ into account.

1.6 Why publish market impact indicators?

The background to this work originated with the release of the existing ACCC service standards guidelines in 2003. These guidelines provide TNSPs with an economic incentive to improve transmission network service quality. The service standards guidelines establish three core performance measures:

- transmission circuit availability
- average outage duration
- frequency of off supply events.

These guidelines provide incentives for TNSPs to improve performance against these measures. Performance targets are set using available data on the TNSPs' historic performance against these measures. Typically the targets are set as an average of the TNSPs' performance over the 3–5 years leading up to their revenue reset. TNSPs are rewarded if they outperform against the target, and penalised if they under-perform against the targets. The rewards and penalties are capped at plus or minus one per cent of annual regulated revenues.

The focus on outages and circuit availability provides a useful starting point for an incentive regime, but also has some limitations. The main limitation is that many outages do not matter. Virtually none cause blackouts, and when they do it is in conjunction with other events. Similarly most outages do not force the National Electricity Market Management Company (NEMMCO) to dispatch more expensive generation and so do not affect price outcomes in the wholesale market.

The existing service standards guidelines partially address these limitations by distinguishing between peak and off-peak periods. However, when the ACCC released these guidelines, it also recognised the potential for further improvements and started as a first step a process to quantify the market impact of transmission congestion. The AER has completed the process started by the ACCC.

The primary objective of this decision is to publish information to improve understanding about transmission congestion. The reported indicators will:

- identify the causes and market impact of transmission constraints
- provide information to participants that can be used as a tool to guide behavioural decisions and promote more efficient market participant behaviour
- be a tool to develop improved service standards incentives.

1.7 Decision to publish indicators

The AER's decision is to publish the following as indicators of the market impact of transmission congestion:

- The **total cost of constraints** (TCC). The TCC estimates how much benefit the market would receive if all transmission constraints were removed. It does this by modelling how much the cost of generation would be reduced if all transmission limits were increased until they no longer affect the dispatch of generation.

- The **outage constraint cost** (OCC). The OCC is similar to the TCC but only estimates the benefit to the market by removing all transmission outage constraints (but retaining other causes of congestion such as system normal constraints). The AER has included this indicator because retailers, generators and other traders are particularly interested in the TNSPs' management of outages. If the impacts of the outages are not predictable or notified well in advance then it can be difficult for traders to manage the associated risks.

- The **marginal cost of constraints** (MCC). The MCC estimates how much benefit the market would receive if a transmission constraint was marginally reduced. It does this by modelling how much the cost of generation would be reduced if the transmission limit was increased by one megawatt. The MCC identifies particular elements of the transmission network that have binding limits that cause generation to be dispatched out of merit order.

For further details on the indicators see appendixes A, B and C.

The final decision is also consistent with the draft decision to publish a qualitative assessment of the TCC, OCC and MCC data. The AER considers the qualitative assessment will increase understanding of how and when transmission constraints impact the market.

The *Indicators of market impact of transmission congestion—report for 2003–04*[7] has been released in conjunction with this decision. Reports for 2004–05 and 2005–06 will be released in the third quarter of 2006.

In the fourth quarter of 2006 the AER will publish TCC, OCC and MCC data on a weekly basis as part of its weekly market analysis reports. The AER will also publish a summary of outcomes as part of its annual state of energy markets report. The first state of the markets report will be released in September/October 2006.

In addition to this information, the AER will make available the *Nature of transmission constraints report*, which TNSPs have undertaken to provide. This report is intended to provide an overview of the types of, and reasons for constraints that occurred during the period. TNSPs have committed to report the nature of transmission constraints starting with the 2004–05 year.

1.8 Developing improved incentives

The AER's objective is to establish incentives that are more directly linked to user benefits and maximise the capability of the transmission system at times that provides most value to users. A well-designed incentive could improve outage management practices, for example, timing of maintenance work, appropriate use of live line work

7 *Indicators of market impact of transmission congestion–report for 2003–04*, AER, 9 June, 2006

and outage notification. It could also improve other aspects of operating practices such as management of line ratings, and possibly investment outcomes as well.

The AER intends to begin a public consultation process to establish a market-based incentive scheme in early 2007. The timing will give the AER and interested parties time to analyse and better understand the TCC, OCC and MCC data. The timing also factors in the Australian Energy Market Commission's (AEMC) review of chapter six of the rules. The AEMC has advised that it will finalise its decision in September 2006, with the rules to start on 1 January 2007.

2 Market impact indicators—submissions and issues

Ten interested parties made submissions on the draft decision: SPI PowerNet (now SP AusNet), TransGrid, Transend, Powerlink, EnergyAustralia, ElectraNet, EUAA, VENCorp, and a joint submission from the ERAA and the NGF.

The majority of submissions supported development of service standards incentives based on market outcomes. They also agreed that market impact indicators are an appropriate first step to achieve this end.

This chapter discusses the issues raised in the submissions along with the AER's decisions. The chapter first provides a brief summary of the draft decision followed by a summary of each of the issues raised in response to the draft decision. The issues are grouped as follows:

- objectives
- alternative indicators
- information reporting
- consistency with the regulatory test as promulgated under clause 5.6.5A of the rules
- treatment of grid support
- economic incentives

The AER's considerations are discussed in the context of each of the identified issues.

2.1 Draft decision

The draft decision sets out criteria to assess each indicator of the market impact of transmission congestion. These criteria are based on consideration of the regulatory framework, underlying principles of economics, technical principles and stakeholder views.

The above factors led to the consideration that the market impact indicators should:

- relate the economic benefit of the TNSP's action to the cost
- depend on, as far as possible, the TNSP's action
- be constructed on objective information and analysis that can be audited
- be understandable and unambiguous
- be consistent across TNSPs

- not be based on assumptions about the importance of any particular factor affecting transmission constraints

- be consistent with the regulator's rules responsibilities.

The draft decision proposed two indicators, the TCC and MCC, and assessed them against the evaluation criteria. The draft decision did not propose the OCC measure, so did not assess it.

Both the TCC and MCC indicators performed well against the evaluation criteria, and the draft decision[8] proposed to report on them. The draft decision also proposed to complement these indicators with a qualitative assessment of the data and the *Nature of transmission constraints report*.

2.2 Objectives

SP AusNet, Powerlink, ElectraNet and the ERAA/NGF raised concerns regarding the objectives set out in the draft decision. They submitted that the objectives do not identify a comprehensive and consistent strategy for transforming the market impact indicators into an incentive scheme.

They also argued the objectives failed to clearly set out the behaviour that the market impact indicators are attempting to encourage. In particular, they requested that the AER identify whether the incentive scheme is intended to target operational decisions, capital investment decisions or both.

2.2.1 AER's considerations

The primary reason for releasing data on the market impact of transmission congestion is to better understand the nature of constraints and to inform the debate about developing improved service standards incentives.

This decision commits the AER to consulting on options for improving service standards incentives, but does not establish a scheme. The AER will use the market impact indicators and supporting analysis as part of its consultation process.

An economic incentive mechanism to address transmission network constraints may involve a system of financial rewards or penalties placed on TNSPs to induce them to improve the quality or quantity of the service they provide. The AER's objective is to link incentives to market outcomes rather than targeting particular behaviour or practices, as the AER considers TNSPs are best placed to determine what behaviour they should adopt to most effectively and efficiently improve market outcomes. Accordingly, the extent to which the incentive targets operational issues or capital investment decisions will ultimately be a matter for the TNSPs.

The more relevant question for the AER is how high or low powered the incentive scheme should be. In general, a low-powered scheme will provide incentives for the TNSPs to implement low-cost measures to improve transmission outcomes. Typically

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8 ibid.

these will be operational changes, such as outage timing and notification and live line work. At the moment, statutory planning standards obligations and the regulatory test are the main drivers of investment outcomes.[9] A relatively high-powered incentive scheme would probably be required to drive significant additional investment.

The AER intends to consult on the power of the incentive along with other elements of an economic incentive in 2007. The issue of economic incentives is discussed in more detail in section 2.8.

The AER considers that the objectives identified in the draft decision form an appropriate basis for informing the choice of market impact indicators. Subject to the outcome of the AEMC's chapter 6 rule change process, the AER will begin a separate consultation process to develop an incentive scheme based on the market impact indicators in early 2007.

2.3 Alternative market impact indicators

Powerlink, ElectraNet and ERAA/NGF suggested that the AER should consider reporting alternative market impact indicators in its reports.

Powerlink and ElectraNet proposed a market impact indicator that would be similar to the TCC but compares the actual cost of dispatch to the cost of dispatch without transmission outage constraints, but with all system normal constraints included. In this decision it is referred to as the outage constraint cost (OCC). Powerlink argued that this indicator could replace the MCC indicator. It also argued that this indicator has the same qualities as the TCC but provides a clearer signal for outage scheduling if the data can be provided to TNSPs within operational timeframes.

The ERAA/NGF put forward an alternative indicator referred to as the partial constraint cost (PCC). They stated that the TCC:

> … compares actual generation costs against a notional dispatch assuming a 'baseline' of infinite transmission capacity, the PCC instead compares actual generation costs against a baseline of a specific, finite level of transmission capacity.

They argued that this indicator could provide a better basis for an economic incentive than the TCC by more closely matching the indicator to the actions subject to the TNSPs' control.

The ERAA/NGF argued that the PCC would help fill the gap between the TCC and the MCC. It would be somewhere between the following:

- relaxing transmission constraints by the notional one megawatt as done by the MCC
- relaxing transmission constraints completely as done by the TCC.

9 Except in Victoria where Vencorp determines network augmentation.

2.3.1 AER's considerations

The AER agrees that it is useful to include a market impact indicator which is more closely aligned to TNSP actions than the TCC. Conceptually, the PCC proposed by the ERAA and NGF goes some way to achieve this. It aims to set a realistic baseline for transmission capacity that may be considered the benchmark level of capacity. Any move towards or away from this benchmark would be considered an improvement or deterioration in TNSP performance. The PCC proposal, however, did not specify what should be used as a realistic baseline.

The OCC addresses the practical limitations of the PCC by defining the baseline as system normal. System normal describes the transmission networks' transfer capabilities with no outages.

The OCC would more closely align the indicator to factors that the TNSPs can control than the TCC. It estimates the market impact of outages that the TNSPs substantially influence or control.

TNSPs determine both the length of planned outages and when the outages take place. For example, some planned outages for maintenance can be taken during off-peak hours to reduce any market impact, and live line work can be used to minimise the length of some outages.

TNSPs do not always have direct control of unplanned outage events, but they can take steps to reduce their likelihood or effect. For example, TNSPs may be able to introduce measures which prevent lightning from causing an outage, or minimise the risk of such outages. Similarly where there is a risk of forced outages the TNSPs can introduce measures to minimise response times.

In the draft decision each indicator proposed was considered against evaluation criteria. The OCC was not a part of the draft decision, so was not assessed against the criteria at that time. However, the OCC is sufficiently similar to the TCC to give comparable results. In two cases it rates higher against the criteria than the TCC:

- it more closely relates the economic benefit of the TNSP's action to the cost
- it is more closely aligned to the TNSP's action.

The AER considers that the OCC provides a useful supplement to the TCC by providing more accurate information on the TNSPs' role in managing congestion.

In addition to the TCC and MCC, the AER intends to publish the OCC. Details of the calculations used to derive the OCC are discussed in appendixes A and B.

2.4 Information reporting

SP AusNet suggested that the market impact indicators should be calculated and provided to TNSPs on a progressive basis, rather than in a quarterly report, to give TNSPs a better response time for high market impact events.

Transend suggested that there should be a threshold for the events reported. It suggested that reporting the top five events in the quarter, with the proviso that each event be above a notional dollar impact, would allow more timely and targeted analysis and avoid mismatch in the scale of events being reported in different quarters.

The ERAA and NGF consider that the ACCC did not have the expertise in market monitoring and analysis. They suggested that reporting and analysis should be the responsibility of the TNSPs. They also raised concerns that the TNSPs only have to make submissions on a voluntary basis, rather than being required to provide information.

The EUAA would like the AER to consider requiring TNSPs to have their service reports independently audited, as well as introduce a standard template for gathering information from TNSPs.

EnergyAustralia argued that the information requested from TNSPs was not appropriate for its network because the operation and performance of its network normally has negligible effect on market settlements.

2.4.1 AER's considerations

Once the AER has completed the first three reports, covering 2003–04, 2004–05 and 2005–06, it intends to publish the TCC, OCC and MCC indicators, and incorporate qualitative analysis of major constraints and their impacts on the market in its weekly market report.

Incorporating new information into NEMMCO's systems is not a simple task. NEMMCO's initial advice is that the TCC can be incorporated into the market system in its November 2006 release, and that the MCC model can be incorporated into the market system in its mid-2007 release. In the meantime, NEMMCO will provide raw data about the effect of constraints to the AER and the AER will share this data with the market.

In undertaking qualitative analysis of the constraint data, the AER will set a threshold, as suggested by Transend, which defines a large market impact. The AER will decide the appropriate level of the threshold before beginning its weekly reporting.

Since the draft decision was released, the AER has been given responsibility for market monitoring and enforcement, taking these over from NECA. Undertaking these functions has added to the AER's expertise in analysing the market impacts of constraints.

The AER will seek TNSPs' views on the constraint data, including the monitoring, compilation and reporting of this data. TNSPs will also be able to provide feedback to the AER through the nature of transmission constraints reports. These reports will cover the nature of constraints for each region using a consistent template.

To date, the AER has calculated the MCC using the same source data as that used by TNSPs in developing the nature of transmission constraints report. This helps the AER to understand how the TNSPs construct the nature of constraints report and will provide a cross-check for both the nature of constraints information and for the MCC.

As to EnergyAustralia's concern, the AER notes that the report contains information largely gathered from NEMMCO's information server. Since NEMMCO only models constraints on the transmission networks and EnergyAustralia is not, for these purposes, a TNSP, it has not been included in this analysis.

The AER will publish the market impact indicators in its weekly and annual reporting. It will also provide analysis of major events. Energy Australia will not be included in the analysis as NEMMCO does not treat its assets as transmission assets for purposes of modelling transmission constraints.

2.5 Availability of the models

Transend and Powerlink both requested that the model used to calculate the TCC be made available to TNSPs. Transend also requested that the AER make clear the inputs, assumptions and calculations used in the NEMMCO model.

Powerlink recommended that the outputs of the model become an integral part of the market information systems available to TNSPs. Powerlink has a preference for the AER using a model that calculates the TCC using the national electricity market dispatch engine (NEMDE) rather than the AER's simplified model.

2.5.1 AER's considerations

In calculating the TCC for its report, the AER has used a model that uses NEMDE. This model was developed by the AER and NEMMCO and is intended to form part of NEMMCO's systems. The AER intends to publish this data in its weekly market reports from the fourth quarter of this year.

To calculate the TCC, NEMDE is run to determine which generators are dispatched using actual bid data. The price of each bid is then multiplied by the quantity dispatched (at that bid price) and summed to give a total cost of dispatch. This calculation is done for two scenarios, with and without constraints. The TCC is the difference in the total cost of dispatch with and without constraints. The OCC is calculated in a similar way, but compares actual outcomes with a system normal base case.

The methodology for calculating the TCC, OCC and MCC are set out in detail in appendixes A, B and C. The AER engaged IES to audit NEMMCO's model to ensure its consistency with the calculations set out in the appendixes.

The AER has published the method of calculating the TCC, OCC and MCC in appendix A, appendix B and appendix C. An IES audit confirms that NEMMCO's model is consistent with the calculations set out in the appendixes.

2.6 Consistency with the regulatory test

SP AusNet, TransGrid, Transend, Powerlink and VENCorp agreed that it is important for the market impact indicators to be consistent with the market benefits calculated for the purposes of the regulatory test.

TransGrid stated that it would be inappropriate to expose TNSPs to incentives related to price separation when investments to relieve constraints need to be justified on the basis of net economic benefits under the regulatory test.

According to Transend the market impact indicators should provide an objective measurement of constraint costs which could also be used by TNSPs when considering alternative options to remove constraints under the regulatory test.

Powerlink expects to be able to use the information derived from these market impact indicators in future regulatory test evaluations.

SP AusNet stated that the TCC seems to be the most consistent with the regulatory test. However, SP AusNet and VENCorp argued that as the TCC uses bid prices rather than actual generator costs (such as fuel costs), it is not identical. They suggested that using notional values for these costs would be more appropriate.

VENCorp added that the market impact indicators are backward looking and do not measure other benefits, such as generation deferment. In contrast, the regulatory test is forward looking and includes other benefits, such generation deferment. Due to these inconsistencies, VENCorp argued the AER needs to clarify that no conclusions could be drawn as to whether the regulatory test could be satisfied using these indicators.

2.6.1 AER's considerations

The regulatory test is designed to enable the assessment of long-term and costly projects which have an impact for many years into the future. It enables TNSPs to identify cost-effective projects.

The AER notes there are reasons to suggest the TCC is closely related to the concept of economic benefits or market benefits of an investment as measured for the purposes of the regulatory test. Therefore, at a high level, the TCC indicator should be broadly consistent with the results of a regulatory test analysis.

However, it is not clear that the TCC reported by the AER could be directly used to assess a prospective project. There are two main reasons for this.

First, it is inappropriate to look at short-term results. Most investments are long lived and should be based on a longer term assessment of outcomes. The TCC results will cover short time periods, at least initially. Stochastic factors, such as weather, can substantially affect outcomes in any given period which in turn reduces the reliability of short samples as a predictor of investment requirements.

Second, the reported TCC is a backward-looking indicator. That is, it is calculated in the context of a specific market outcome that arose at a particular point in time in the past. An analysis of a prospective transmission project must be forward-looking. That is, it must consider all of the possible market outcomes that may arise in the future (for example, different levels of demand, or different combinations of outages of generators, or elements of the transmission network).

In theory, a TNSP could create a forward-looking indicator similar to the TCC for a specific time interval in the future for two scenarios—with and without the proposed investment. The difference in the forward-looking indicator for these two scenarios would be an indicator of the economic benefit of the proposed investment during that time interval. In principle, this amount should be very similar to the economic benefits calculated for the regulatory test.

However, the regulatory test approach raises issues such as whether changes in dispatch should be valued by an external estimate of generator costs or an estimate of generator bids. The traditional approach to estimating the market benefits under the regulatory test uses an external estimate of generator marginal costs. Using a forward-looking indicator would require a forecast of generator bidding behaviour, which would raise further issues.

Another issue is that for time intervals further in the future, it would be necessary to model the investment decisions of generators and the effect of the proposed project on those investment decisions (such as whether or not to defer an investment). In addition, a forward-looking indicator similar to the TCC would have to model other changes to the network that would have an interdependent relationship with the investment being assessed.

The AER is not confident that such a dynamic, forward-looking assessment can be made. Observing how the market changes over time based on actual market data is a difficult task. To extrapolate such an assessment into the future requires many more assumptions and would be open to criticism.

The regulatory test is a tool for assessing the future costs and benefits of a project. It provides a basis for rigorously assessing investment proposals. While there is considerable overlap between the regulatory test and the TCC, the TCC uses existing data to provide a backward-looking assessment of the cost of congestion. It may help to inform forecasts, but is not a substitute for the regulatory test.

The AER intends to use the TCC and other market impact data for transparency purposes and as the basis for a new or revised service standards incentive. The TCC should not be seen as an investment planning tool.

2.7 Treatment of grid support

During the development of the TCC model, the AER received several comments about grid support. There was a general consensus from TNSPs that grid support was a substitute for an augmentation and therefore no cost of constraint should be attributed to the TCC indicator.

2.7.1 AER's considerations

In some regions, for short periods, transmission capacity is inadequate to meet high levels of demand. A number of TNSPs enter into grid support contracts with generators to supply electricity in such circumstances. Grid support agreements can be a cost-effective alternative to transmission augmentation.

The problem identified by the TNSPs is that generators can bid into the market even if they are being dispatched under a grid support agreement. When the grid support agreement is triggered the real cost to the market is the price struck under the grid support contract. If the generator's bidding in the market is also included in the TCC calculation, the result is a double count. Typically generators in these circumstances bid high (up to $10,000/MWh) knowing that this bid is ignored by NEMDE and that it is instead dispatched in accordance with the grid support agreement. Including the bids can therefore have a substantial impact on the TCC.

The AER agrees that the TCC model in the draft decision over-states costs associated with constraints where grid support is used, and has removed the effect of those constraints in the published TCC.

This issue is discussed in more detail in appendix A.4

The AER has determined that the dispatch costs of generators subject to network support agreements will not be included in the calculation of the TCC.

2.8 Estimating generation costs

One of the issues raised in the working group is how best to calculate the marginal costs of generation. More specifically, why not use a bottom-up estimate of generator marginal costs rather than its bids?

2.8.1 AER's considerations

The TCC is intended to be an indicator of the increase in economic welfare that would occur if all congestion on the transmission network were removed. It does this by measuring how much the dispatch cost (that is, the cost of producing sufficient electricity to meet total demand) is increased by the presence of transmission constraints.

Dispatch costs are measured by adding up the marginal costs of producing each megawatt of energy. The question for the AER is how to measure or estimate these marginal costs. Two options are available.

The first option is to estimate the marginal cost using engineering cost assessments. The main limitation of this approach is that it involves a significant degree of judgment by the regulator.

The second option is to use generator bids as an estimate of marginal costs. The AER has chosen to use bid data because:

- bids are readily observable and publicly available, which increases the transparency of the indicators
- using bids avoids the regulator making a judgment about the appropriate cost to use.

The AER recognises that generator offer curves do not always reflect their underlying marginal cost, particularly when a generator is constrained on or constrained off relative to the regional reference price. The AER will take this into account in considering options for setting an economic incentive.

2.9 Economic incentives

SP AusNet, TransGrid, ERAA/NGF and Transend stated that it is not clear that the proposed indicators will be effective for use in a financial incentive scheme.

TransGrid considered that similar evaluation criteria to those developed for the market impact indicators will need to be developed for the economic incentives. It raised concerns that any future market impact service standard incentives should relate to the actions of TNSPs rather than be affected by the behaviour of other market participants. It also believes the incentives need to be symmetric.

According to Transend the issue of who pays needs to be considered. It states that the principal beneficiaries should pay for service improvements.

The EUAA supported development of an economic incentive and encourages the AER to do so as soon as possible. The EUAA also considers that publication of TCC and MCC data will help to identify substantial infrastructure constraints.

2.9.1 AER's considerations

Currently a service standards incentive scheme exists in seven TNSPs' revenue caps. These incentive schemes are based on the service standards guidelines and seek to address the incentives for TNSPs to reduce costs within a revenue cap at the expense of service quality. These guidelines set out an incentive scheme that increases the TNSP's revenue cap if it improves the output of the transmission network.

To achieve increased revenue TNSPs must target improvement in measures such as network availability, average network outage times and frequency of network outages. The incentive scheme is not biased to addressing the cost of congestion and TNSPs have an incentive to reduce outages at all times, not just when the outage could adversely affect the market.

To enhance the incentive on TNSPs to address congestion at times when it has the greatest market impact the AER aims to establish an incentive scheme that closely relates rewards and penalties to TNSP actions. While the TCC and MCC indicators may not achieve this in themselves, they can be used as the basis for developing a range of incentive options. Further the OCC data should provide useful information in designing an incentive that closely matches rewards and penalties to TNSP actions.

When the AER undertakes further work to develop and assess incentive options it will consider the issues raised by SP AusNet, TransGrid, Transend, the ERAA and the NGF. In the meantime reporting the indicators will help to inform the debate about economic incentives. The AEMC is currently undertaking a review of chapter 6 of the rules, including whether there should be specific provisions for the AER to introduce market impact incentives. After the AEMC has released its final decision on the review of chapter 6 of the rules, the AER will begin consultation in line with the rules.

The AER aims to develop a service standards incentive scheme drawing on the market impact indicators in this decision. It will begin a public consultation process on the economic incentives early in 2007. In the meantime releasing market impact transparency reports will help to inform the debate about economic incentives.

3 Future work plan

NEMMCO has calculated the TCC and OCC to the AER's specification for 2003–04. The AER has also calculated the MCC for 2003–04. These indicators are shown in the attached report *Indicators of the market impact of transmission congestion–report for 2003–04.*

The AER anticipates that NEMMCO will have calculated the TCC and OCC to the AER's specification by the end of the third quarter 2006, for:

- 2004–05
- 2005–06.

The AER will have also calculated the MCC for the same periods by the end of the third quarter 2006.

After the AEMC has released its final decision on the review of chapter 6 of the rules, the AER will begin consultation in line with the rules. At this stage the AER anticipates starting the process in early 2007.

The AER will start its consultation process with an options paper. The process will also include a draft decision, providing details of one preferred way forward and/or an amended set of service standard guidelines.

The AER will continue to draw on the expertise and input of the service standards working group.

Appendix A : TCC and OCC calculation

NEMDE's objective function is broadly to minimise the dispatch cost of generation in the NEM.[10] The objective function is the sum, for all generators, of:

generator offer prices x capacity dispatched at those offer prices

For a given five-minute interval, the TCC is then computed as:

$$\text{objective function}^{\text{constrained case}} - \text{objective function}^{\text{unconstrained case}}$$

Where:

objective function$^{\text{constrained case}}$: is the dispatch cost that is determined by NEMDE taking into account the all the transmission constraints, the demand, generator offers and demand-side bids as in the actual 'production run' used to determine the actual dispatch each five minutes in the NEM.

objective function$^{\text{unconstrained case}}$: is the dispatch cost that is determined by NEMDE, using the same demand, generator offers and demand-side bids as the constrained case above but when all transmission constraints are removed.

Similarly, for a given five-minute interval, the OCC is computed as:

$$\text{objective function}^{\text{constrained case}} - \text{objective function}^{\text{system normal case}}$$

Where:

objective function$^{\text{constrained case}}$: is the dispatch cost that is determined by NEMDE taking into account the all the transmission constraints, the demand, generator offers and demand-side bids as in the actual 'production run' used to determine the actual dispatch each five minutes in the NEM.

objective function$^{\text{system normal case}}$: is the dispatch cost that is determined by NEMDE, using the same demand, generator offers and demand-side bids as the constrained case above but when all transmission outage constraints are removed.

10 The NEMDE objective function also takes into account (a) demand side bids; (b) the bids of MNSPs; (c) the costs of ancillary services; and (d) constraint violation penalties (as discussed earlier). These other factors complicate this presentation and so will be ignored here for simplicity.

The AER/NEMMCO working group was established to work through how this calculation could be undertaken. There were many complicated issues associated with calculating the TCC. As part of this process the AER also worked through other issues in calculating the TCC as discussed in appendix B.

A.1 Constraint violation penalties

Constraint violation penalties allow NEMDE to 'prioritise' constraints to find a solution when no solution is possible without violating at least one constraint. These constraint violation penalties are added to the underlying dispatch cost to form the 'objective function' which is minimised by NEMDE. The TCC is intended to measure only the real physical costs of changes in dispatch. Therefore, for the purposes of computing the TCC, the AER calculates only the underlying dispatch cost. (This will differ from the actual objective function minimised by NEMDE).

A.2 Ancillary services costs

The turnover in the ancillary services market accounts for less than one per cent of the turnover in the energy market. Network constraints may, under certain rare circumstances, affect the cost of ancillary services. However, given the relatively small size of the ancillary services market and the limited impact of network constraints on that market, the AER has decided to focus on the impact of network constraints on the cost of dispatch in the energy market. For this reason the ancillary services costs have been removed in the calculation of the TCC.

In some circumstances, outcomes in the ancillary services markets will cause a direct cost on the dispatch of generation in the energy market, which means they should not be completely ignored. This only occurs for a relatively small amount of the time.

A.3 Ramp rate constraints

In theory, if a set of constraint equations (in this case, transmission constraints) are removed from a minimisation problem, the objective function should reduce and therefore the TCC should be positive. However, early testing of the TCC showed that this was not always the case because of issues associated with generator ramp rates.

The following explains this counter intuitive outcome, which is easily highlighted with the example of zero ramp rates shown in

Table 1–Effect of ramp rates on TCC

Generator parameters	Actual dispatch (constrained case)	No transmission constraints dispatch (unconstrained case)
Offer price ($/MWh)	10 000	10 000
Capacity offered (MW)	350	350
Ramp rate (MW/hr)	0	0
Starting output (MW)	200	350
Target output (MW)	200	350
Dispatch cost ($)	=200 x 10 000 **2 000 000**	=350 x 10 000 **3 500 000**

In this example, the generator has been dispatched for a higher level in the unconstrained case. It has then bid a zero ramp rate. The effect of the zero ramp rate is to hold its dispatch at this higher level even when the underlying constraint (which caused the dispatch to be higher in the first place) has been removed. Subsequently, the dispatch cost is higher in the unconstrained case and the TCC is negative.

Given that the TCC is the difference between the objective function for the constrained and unconstrained cases, for this example, the impact of a single generator on the TCC is:

= (offer price x target dispatch)$^{\text{constrained case}}$ – (offer price x target dispatch)$^{\text{unconstrained case}}$

= (10 000 x 200) – (10 000 x 350)

= (2 000 000) – (3 500 000)

= - $1 500 000

In this case it appears that transmission constraints reduce the cost of dispatching generation by $1 500 000. While in fact, the combination of the generator's starting output and its ramp rate constraint produced this result.

There were two alternatives that could have addressed this issue:

- Resetting the generator's initial output in the unconstrained case, in each five-minute interval, to that of the generators initial output in the constrained case.
- Remove the ramp rate constraints from both the constrained and unconstrained cases.

The AER considered both options and decided on the latter. To reset a generator's initial output to be the same in both the constrained and unconstrained cases would (in the presence of ramp rate constraints) prevent the generator from moving to its optimal dispatch and therefore would result in only partial measurement of the impact of transmission constraints. There would always be a question about how much of the cost of transmission constraints was hidden by the effect of generator ramp rates.

Therefore the AER has removed the ramp rate constraints in both the constrained and unconstrained cases.

A.4 Grid support constraints

The TCC is an indicator of only the benefits from relieving transmission constraints In comparing two approaches for relieving transmission constraints, a comparison should be made between the benefits (as reflected in the reduction in the TCC) and the cost (not reflected in the TCC).

In principle, the reduction in the TCC should correctly capture all of the benefits of any approach for relieving transmission constraints—whether that approach involves network augmentation or a non-network solution. If the indicator of the benefits, that is the TCC, systematically excluded any benefits of any option, then that option would be disadvantaged in a cost-benefit analysis.

This can be made clearer through an example. For the purpose of this example, assume that load growth in far-north Queensland was expected to exceed the transmission limit in five years time. In the absence of any action, 10 MW of load would have to be shed for on average one hour per annum.

The TNSP has two options to relieve the constraint. First, is a network augmentation at a hypothetical cost of $99 000 per annum. Second is a grid-support agreement with a new generator, at a hypothetical cost of $94 000 per annum. Table 2 shows that not only are the costs of these options different but the benefits are also different.

Table 2–Grid support versus augmentation

Option	Cost	Gross benefit	Net benefit
Augmentation	$99 000 per annum of annualised cost	By augmenting the network, load would not need to be shed (with a value of $10 000/MWh) and instead would be replaced with low-cost generation from elsewhere in the network at a cost of, say, $30/MWh. Total reduction in the TCC is $9 970 x 10 = **$99 700 per annum.**	$700
Grid support	$94 000 of annual payment to a generator.	By arranging grid support, load would not need to be shed (with a value of $10 000/MWh) and would be replaced with high-cost local generation at a cost of, say, say $300/MWh. Total reduction in the TCC is $9 700 x 10 = **$97 000 per annum.**	$3 000

In this example, the reduction in the TCC from the augmentation is $99 700 and is $97 000 for the grid support agreement. Based on these gross benefits the network augmentation appears to be the preferable option. However, the network augmentation also has higher costs and therefore, when considering the net benefit, the grid support option is the economically efficient solution for addressing this constraint.

Given the TCC is a measure of the gross benefits; it must correctly capture the economic costs of the transmission limit that the grid support is managing.

Having noted that, in principle, the TCC should include the dispatch cost of generators which are involved in network support agreements, in practice this may not always be feasible.

There are two ways that grid support agreements can be implemented in the market systems, these are:

1. The generator could agree to bid the required level of capacity at a low price, such that it is automatically dispatched when required by the network support agreement. In this case, the relevant transmission limit is not reflected in a constraint equation in NEMDE. In this situation the TCC model does not correctly capture the gross benefits of removing that underlying constraint.

2. The grid support agreement could be represented as a constraint equation, which would restrict the generator's output in accordance with the agreement regardless of its bid. In this situation the TCC would correctly reflect the benefits of relaxing that constraint equation, but only if the generator's underlying bid correctly reflected its true marginal cost—but in this circumstance the generator (whose output is independent of its bid) has no incentive to submit a bid which reflects its marginal cost.

In the cases where a grid support agreement is represented in NEMDE as a constraint on the output of a generator, that generator will not have an incentive to submit an offer which correctly reflects its true marginal cost. The TCC for 2003–04 reveal that many 'constrained-on' generators, providing grid support, are offering their output at VoLL. Since the true marginal cost of these generators is likely to be significantly less than $10 000/MW, the resulting TCC significantly over-estimates the value of relieving the underlying transmission constraint.

To correct for this over-estimation, it is necessary to replace the $10 000 offer of these generators with a value which more closely reflects their true marginal cost. The marginal cost of peaking generation plant, which is commonly used for grid support, is more likely to be in the order of $300/MWh, rather than $10 000/MWh. Therefore the gross benefit of removing the transmission constraint (and the grid support arrangements) is akin to a reduction from $300/MWh to the bid price of the least cost generator that would have been dispatched if a network augmentation was constructed.

The AER considered making this correction to the TCC—that is replacing the $10 000/MWh offer of these generators with a $300/MWh offer. This approach, while significantly reducing the over-estimation of the TCC, leads to an inconsistency in the treatment of grid support agreements reflected in constraint equations compared to those grid support agreements not reflected in constraint equations.

Until these issues have been resolved the AER has decided to remove grid support constraint equations from the TCC calculation. This has the following advantages:

- the resulting TCC is a more realistic indicator than relying on $10 000/MWh bids, which overvalue the benefits of relieving these constraints

- all grid support arrangements are treated consistently regardless of how they are implemented in the market systems

- the AER is not required to decide an appropriate marginal cost for grid support generators.

Appendix B : TCC calculation 'frequently asked questions'

This appendix was prepared by Dr Darryl Biggar, an internal consultant to the AER. The purpose is to respond in further detail to questions that have arisen as individuals have sought to understand the AER's proposed approach to computation of the 'total' cost of transmission constraints (the TCC measure).

The questions addressed in this appendix are as follows:

- How does the AER propose to calculate the TCC?
- What assumptions have been made about losses in the no network constraints (NNC) run of the model?
- How is load-shedding handled?
- Why isn't the TCC just equal to the difference in the value of the NEMDE objective function between the ANC and the NNC runs?
- Why have the generator ramp rate constraints been relaxed? Wouldn't it be possible to obtain a more realistic measure of the cost of transmission constraints if ramp rate constraints were included?
- Does relaxing the ramp rates lead to an over-estimate or an under-estimate of the 'true' TCC?
- Why have the FCAS markets been ignored? Are there not occasions where network constraints may give rise to high costs in the FCAS markets?
- Why does the proposed approach compute the cost of transmission constraints using generator offer curves? Does it not make more sense to base the calculation on the actual cost of each generator?
- How has the AER handled 'fixed-load' constraints?
- Why is the OCC measure sometimes negative?
- What happens when a generator is dispatched to a target which exceeds the maximum amount it has declared that it is available to produce?

How does the AER propose to calculate the TCC?

To understand the TCC measure it is useful to first understand the concepts of 'dispatch' and 'dispatch cost' and the task of the NEM dispatch engine.
A 'dispatch' is a set of production targets for all of the scheduled generators (and scheduled loads) in the NEM. The cost of a dispatch or 'dispatch cost' is the sum of the variable costs incurred by each generator in producing the target quantity of electricity. The task of the dispatch engine can be thought of as finding the dispatch

which minimizes the total 'dispatch cost' subject to meeting all of the physical constraints of the network.

Intuitively, we would expect that relaxing the physical constraints on the network would allow the dispatch engine to find a lower-cost dispatch. This difference in the minimum dispatch cost with network constraints and without network constraints is a measure of how much the network constraints are raising the cost of dispatch. It is this amount which is captured in the TCC measure. The TCC for a time period is roughly a measure of how much transmission constraints raise the total cost of producing energy to meet the total demand in that period.

More specifically, in the approach proposed by the AER, the TCC is defined to be the difference in the dispatch cost between two runs of the dispatch engine—the ANC run and the NNC run.

The ANC (all network constraints) run is similar to the actual run of the dispatch engine which, every five minutes, produces the actual real-time dispatch targets. The ANC run uses the same demand conditions, and combination of bids and offers as the real-time dispatch and uses the same network constraints as the real-time-dispatch. However, in the ANC run, ramp rate constraints, FCAS markets and FCAS constraints, and fast-start-related provisions are all ignored.

The NNC run is identical to the ANC run except that, in addition, all network constraints are ignored and the physical limits on interconnectors are expanded up to a level such that the interconnector physical limits will never bind.
In addition, the AER also computes the difference in the dispatch cost between the ANC run and another run of the dispatch engine in which only system normal constraints (SNC) are retained.

The differences between the ANC, SNC and NNC runs are summarised in the following table:

	ANC run	NNC run	SNC run
Initial conditions	As in real time dispatch	As in real time dispatch	As in real time dispatch
Ramp rate constraints	Ignored	Ignored	Ignored
FCAS constraints and FCAS markets	Ignored	Ignored	Ignored
Network constraints	As in real time dispatch	All eliminated	All except 'system normal' constraints eliminated
Interconnector limits	As in real time dispatch	Relaxed	Relaxed

Under the AER approach, for each five-minute dispatch interval, the NEM dispatch engine is re-run three times—to compute the optimal dispatch in the ANC run, the NNC run, and the SNC run (which is described below).

Once the optimal dispatch in each run is determined, the 'dispatch cost' is computed as equal to, for each generator, the area under the offer curve for that generator—that is, for each generator, the sum of the quantity dispatched in each price band times the price for that price-band. [11] The TCC is then calculated as the dispatch cost in the ANC run less the dispatch cost in the NNC run.[12]

To illustrate how this might work in practice, the following table sets out the dispatch cost computed for the dispatch interval known as '20050401120' or 2 pm on 1 April 2005. The total dispatch cost in the ANC run (which includes network constraints) was $-8836766.7/h.[13] The total dispatch cost in the NNC run (which excludes network constraints was $-8843913.5/h. The TCC measure was therefore $7146.8/h.

Computation of the TCC for interval ending 2 pm, 1 April 2005

Run	Dispatch cost ($)
ANC	-8836766.7
NNC	-8843913.5
Difference (TCC)	7146.8

The TCC for a longer time period (such as for a day, week, month or quarter) is the sum of the TCC's for each interval in that period divided by the number of intervals per hour. The TCC is measured in $ per unit of time. A TCC over one hour of $1000 implies that the total cost of producing sufficient energy to meet demand in that hour was $1000 higher than it would have been if all transmission constraints had been eliminated.

The TCC must be non-negative (that is, positive or zero). The TCC can only be positive in an interval in which at least one network constraint is binding. For example, in the interval mentioned above (20050401120), the following constraints were binding: Q>NIL_757+758_B; V:S_NPS_SINGL_C and V^SML_NIL2.

The AER also proposes to compute the cost of just those constraints which are not part of the SNC set(s)—that is, the cost of 'outage' constraints. The OCC measure is equal to the difference between the dispatch cost in the ANC run and the dispatch cost in the SNC run. Like the ANC run, the SNC run starts from the same initial conditions as the real-time dispatch and ignores ramp rates, FCAS markets and FCAS constraints, and fast-start related provisions. Unlike the ANC run, however, all network constraints which are not SNC are removed.

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[11] Similarly, for scheduled load, the dispatch cost is effectively the area above the bid curve or, the sum of the quantity dispatched in each price band times the price of that price band.

[12] The TCC calculation will include the dispatch cost for generators in Tasmania, although in the tests done to date Tasmania (which had not entered the NEM at the time) is excluded.

[13] The dispatch cost can be negative. This arises because many generators bid a portion of their offer curve at a negative price.

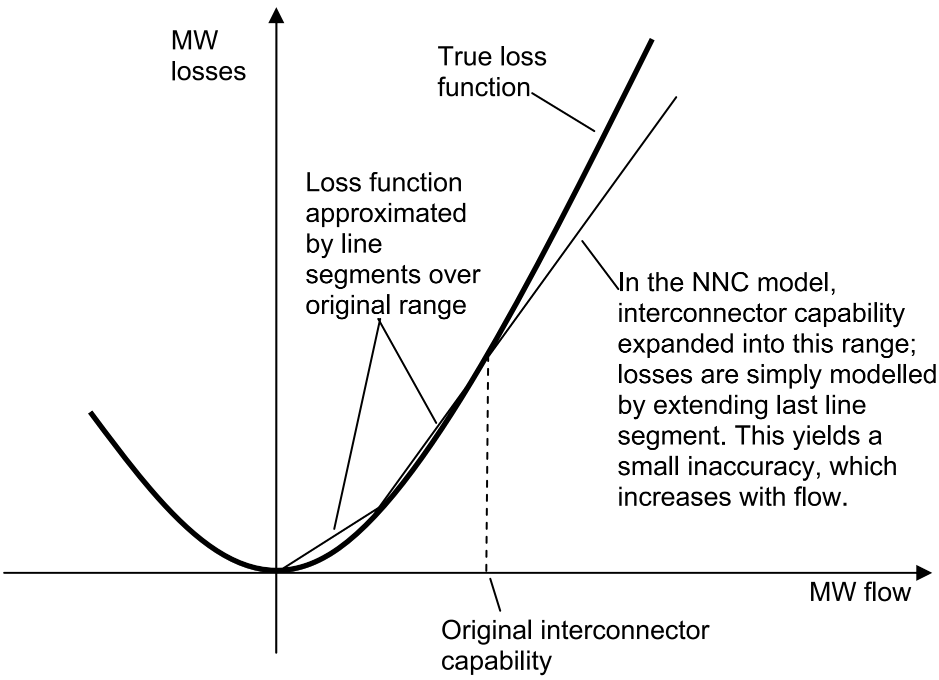
What assumptions have been made about losses in the NNC run of the model?

The NEM dispatch engine reflects intra-regional losses through static marginal loss-factors which are updated on an annual basis. Inter-regional losses are captured in a 'loss model' which is designed to reflect the physical losses on the interconnectors between regions in the transmission network. This loss model approximates the 'true' losses on an interconnector as a series of line segments.

In the NNC run, the physical limits on interconnectors are relaxed, potentially allowing much higher interconnector flows. In principle, the loss model should also be extended to cover this new range—that is, in principle, a number of additional line segments should be added to the loss model, to better reflect the actual losses in the extended range.

However, extending the loss model in this way would be time-consuming and, in practice, it appears that interconnectors in the NNC run are seldom dispatched for more than their existing physical capability. As a result, for the present time, the losses in the extended range for each interconnector are simply modeled as an extension of the last line segment for each interconnector.

This approach appears to be an acceptable approximation for the moment. However, this is an issue which should be kept under review. In future refinements of the TCC model, further improvements to the loss model in the extended range of the NNC run should be considered.



How is load-shedding handled?

In principle, if a network constraint causes load to be shed, that lost load should be valued, for the purposes of computing the dispatch cost, at some value equal to or in excess of the amount known as the 'value of lost load' or $10 000/MWh. However, in practice, load shedding is highly unlikely to emerge directly as an outcome from the dispatch engine. Instead, the dispatch engine will typically violate some other constraint (such as a flow constraint on an interconnector). Once a physical constraint on an interconnector has been violated the NEMMCO operators have up to 30 minutes to restore the system to a secure state. If violation of a constraint is forecast to last for more than a short period of time, the NEMMCO operator will have no choice but to shed load, according to pre-determined protocols, through actions taken outside of the NEM dispatch engine.

At present, the TCC calculation is based exclusively on the output of the NEM dispatch engine. Therefore, under the proposed approach, the 'cost' of load-shedding will not be reflected in the TCC. Even though load-shedding as a result of network constraints is rare, since its cost is large when it does occur, the impact of load shedding is non-negligible.

It may be possible to incorporate the cost of load shedding through some form of 'post-processing' of the raw TCC data. This is a matter which will need to be explored in the future.

Why isn't the TCC just equal to the difference in the value of the objective function between the ANC and the NNC runs?

As mentioned above, the NEM dispatch engine can be thought of as minimising the 'dispatch cost' subject to certain constraints. In fact, the objective function which is minimised by the NEM dispatch engine is very similar to the concept of the 'dispatch cost' set out above. Couldn't we compute the TCC by simply looking at the difference in the objective function as used by the NEM dispatch engine?

Unfortunately, although the concept of 'dispatch cost' as described above is very similar to the NEMDE objective function, the two are not the same. The primary difference relates to constraint violation penalties. The NEMDE objective function allows for constraints to be breached, if necessary, but prevents this outcome under normal circumstances by penalizing such breaches with very large penalties in the objective function known as 'constraint violation penalties'. These penalties are many times VoLL and therefore have a significant impact on the NEMDE objective function. If the TCC were calculated on the basis of the NEMDE objective function, it would be affected by constraint violation penalties which do not reflect the cost of generation as determined through generator offers.

The NEMDE objective function could, in principle, be decomposed into two components: (a) the underlying 'dispatch cost' and (b) the impact of constraint violation penalties. In any interval in which no constraints are violated the impact of constraint violation penalties will be zero, so that the dispatch cost and the objective function will be the same. At other times, however, the two will differ.

In principle it would be possible to compute the 'dispatch cost' from the NEMDE objective function by subtracting out the impact of constraint violation penalties. Computing the dispatch cost in this way would provide a useful 'double-check' of the accuracy of the dispatch cost calculation described above.

Why have the generator ramp rate constraints been relaxed? Wouldn't it be possible to obtain a more 'realistic' measure of the cost of transmission constraints if ramp rate constraints were included?

In principle, it is desirable to measure the impact of transmission constraints in a way which takes into account as much of the physical realities of generation and transmission businesses as possible. Since generator ramp rate constraints usually reflect the real physical limits on generators, in principle it is desirable for these to be included in the computation of the TCC.

In fact, in the AER's first attempt at computing the TCC the impact of generator ramp rate constraints were taken into account. However, it quickly emerged that including generator ramp rate constraints gave rise to significant problems.

Part of the reason for these problems is that, in the presence of ramp rate constraints, the 'initial conditions' at the start of each dispatch interval affect the optimal or target dispatch at the end of that dispatch interval. In the real physical network these initial conditions are observed from SCADA data every five minutes. However, in the NNC run (since it is a counter-factual) no such corresponding SCADA data is available. Instead, assumptions must be made about the likely initial conditions for each generator for each dispatch interval. In the AER's first attempt at computing the TCC, the assumption was made that each generator was perfectly conforming—that is, by the end of each dispatch interval, each generator was producing an amount equal to the target dispatch given at the start of the same interval.

Under this approach, since the initial conditions are different under the ANC and the NNC runs, the dispatch targets in the NNC and the ANC runs may diverge from each other to an arbitrarily large amount (although, in principle, they should re-converge during periods without transmission constraints).

As mentioned above, problems quickly emerged with this approach. To illustrate, suppose that a generator is currently producing 100 MW in the ANC run and is producing 200 MW in the NNC. Suppose that this generator has a ramp rate of 100 MW per dispatch interval. Now suppose that this generator wishes to shut down. It does so by bidding all of its output at VoLL. As a result, in the ANC run it is given a target of zero. In the NNC run, it is given a target of 100 MW (due to the ramp constraint). Suppose that once the generator has reached zero in the ANC run, it then bids a ramp rate of zero, in order to remain at zero. However, in the NNC run this has the effect of holding the generator at 100 MW indefinitely.

If all of the output of this generator is bid at VoLL, this additional 100 MW of output priced at VoLL, adds $1 million to the dispatch cost in the NNC for each dispatch interval. As a result the TCC is both large and *negative*.

As we noted earlier, the expectation of the AER is that the TCC will be non-negative. Experience with the initial trial of the TCC approach showed that intervals with negative TCC were relatively common, seriously undermining the usefulness of this first attempt at computing the TCC.

After deliberation on this problem and discussion with NEMMCO it was decided to simply ignore the ramp rate constraints. This approach has the significant advantage that the dispatch chosen by the dispatch engine each interval is no longer dependent on the initial conditions. As a result, the dispatch in the ANC run may diverge arbitrarily far from the dispatch in the NNC run, whatever the initial conditions, or whatever the starting date of the NNC run. In fact, it is not even necessary to compute consecutive dispatch intervals at all—a sample of dispatch intervals can be computed, whether they are consecutive or not.

Another possible approach has been suggested—that is, to retain the ramp rate constraints, but simply to set the initial conditions the same for both the ANC and the NNC run in each dispatch interval.

The primary drawback with this approach is that the resulting TCC has no obvious economic or physical interpretation. Under this approach, the extent to which the dispatch in the ANC run and the NNC run can diverge is limited by the size of the ramp rate constraints. If the ramp rate constraints are small, the ANC run and the NNC run will not be able to diverge very much from each other and from the initial conditions. For this reason, the TCC computed under this approach would be expected to be much smaller than an approach which ignored the ramp rate constraints—but in a way which has no economic interpretation.

Does relaxing the ramp rates lead to an over-estimate or an under-estimate of the ‘true’ TCC?

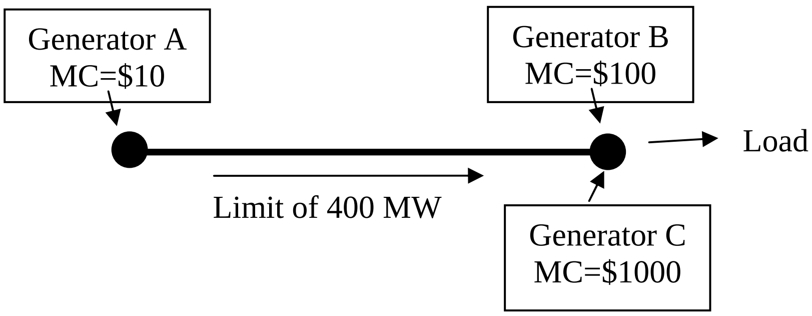
What might be meant by the ‘true’ TCC? One possibility is the computation of the TCC incorporating ramp rate constraints as described above. But we saw above that this approach, on occasion, yields results (such as negative TCCs) which are difficult to interpret. It is therefore questionable that this approach is a reliable measure of the ‘true’ cost of transmission constraints.

Nevertheless, let’s make the assumption that this approach accurately captures the ‘true’ cost of transmission constraints, at least in the examples we will consider below. Does relaxing the ramp rate constraints yield an over-estimate or an under-estimate of this ‘true’ cost of transmission constraints?

Unfortunately, the interaction between ramp rate constraints and transmission constraints is complex. It is easy to find examples where the proposed approach yields a higher apparent cost of transmission constraints and other examples where the proposed approach yields a lower apparent cost of transmission constraints, relative to an approach incorporating ramp rate constraints. The AER has not yet found an argument which demonstrates that the proposed approach is systematically biased to over-estimate or under-estimate the cost of transmission constraints relative to an approach incorporating ramp rate constraints.

To illustrate this, consider the following network. This is a network with two nodes, one transmission link, and three generators with variable cost \$10, \$100 and \$1000 respectively. The initial dispatch of these generators is 400, 50 and 0, respectively.

Generator B has a ramp rate limit of zero. The forecast load for the next interval is higher, at 500 MW.



Taking into account the transmission constraint (i.e., in the ANC run), the new dispatch for the next interval is then (400,50,50), which has a total dispatch cost of $59,000. Ignoring the transmission constraint, the new optimal dispatch is (450,50,0), which has a total dispatch cost of $9500. So, the total cost of transmission constraints including ramp rate restrictions is $49 500.

Ignoring ramp rate limits, the optimal dispatch with the transmission constraint is (400,100,0), which has a dispatch cost of $14 000. The optimal dispatch without the transmission constraint is (500,0,0) which has a dispatch cost of $5000. The TCC ignoring ramp rate limits is therefore $5000. Clearly, under these assumptions, the AER proposed approach significantly under-estimates the 'true' TCC.

Now suppose that the forecast load for the next interval is lower, down to 410 MW. Now, if we take into account ramp rate constraints, the new optimal dispatch is (360,50,0), whether or not network constraints are taken into account (the network constraint is not binding in this dispatch), so the TCC including ramp rate restrictions is zero.

Ignoring ramp rate limits, the optimal dispatch with the network limit is (400,10,0), with a dispatch cost of $5000. The optimal dispatch without the network limit is (410,0,0), with a dispatch cost of $4100. The TCC ignoring ramp rate limits is therefore $900. With this simple change to the load we find that now the proposed AER approach is an over-estimate of the 'true' TCC.

At this stage it is not possible to assert that the proposed AER approach of relaxing the ramp rate constraints yields an estimate of the cost of transmission constraints which is systematically an over-estimate or an under-estimate.

Why have the FCAS markets been ignored? Are there not occasions where network constraints may give rise to high costs in the FCAS markets?

It is true that there are occasions where network constraints may have an impact on the cost incurred in purchasing frequency control ancillary services (FCAS). Under system normal conditions (in particular, in the absence of any outages on interconnectors), FCAS are bought on a NEM-wide basis. That is, any generator, located anywhere in the NEM can, in principle compete to offer FCAS services.

However, under certain network conditions, FCAS services must be bought 'locally' which may significantly raise the cost of obtaining the desired level of FCAS services.

This may arise, for example, in the event that one transmission line of a pair of transmission lines which make up an interconnector is out of service (perhaps for maintenance). In this event, the loss of the remaining transmission line is considered to be a 'single contingency' for risk management purposes. This means that NEMMCO must buy enough contingent raise or lower service 'locally' to cover the potential loss of that transmission line. This contingent raise or lower service must be purchased within the region which would be isolated in the event of the outage of the remaining transmission line.

For example, suppose that an outage on QNI is classified as a single contingency at a time when QNI is exporting 500 MW north into Queensland. In this event, NEMMCO must buy a little less than 500 MW of 'raise' service in Queensland to cover the potential loss of QNI (the requirement is a little less than the flow on QNI due to an allowance for demand reduction with frequency fall). Similarly, NEMMCO must buy a 500 MW lower service in the remaining interconnected part of the NEM. If there is a shortage of raise service in Queensland, the cost of buying the required FCAS services in Queensland may increase considerably.

In other words, network constraints may sometimes give rise to higher FCAS market costs. However, under the current AER proposed approach, FCAS markets and FCAS constraints are ignored due to particular modelling complexities that FCAS markets would introduce. These problems arise due to the interaction between a generator's current level of dispatch and the 'FCAS trapezium'.

All generators who participate in the FCAS markets must signal to the dispatch engine their ability to provide FCAS services. The ability of a generator to provide FCAS services depends in part on the generator's current level of output. A generator which is currently producing nothing cannot provide a 'lower' service. A generator which is currently producing at its maximum output cannot provide a 'raise' service. Generators signal their availability to provide FCAS services in a generic way by describing to the dispatch engine the 'envelope' (which takes the shape of a trapezium) of their capability to provide these services.

Due to a quirk in the dispatch engine, a generator which is currently outside this envelope in one period will not be allowed to be dispatched inside the envelope in subsequent periods. This is known as being 'stranded'. For this generator to be dispatched inside its trapezium in subsequent periods the generator must re-bid the shape of its trapezium to include its current dispatch. Similarly, a generator which is currently operating inside its envelope or trapezium will not be dispatched outside that envelope, no matter what other forces are operating. A generator which is being held inside its FCAS trapezium despite other factors is said to be 'trapped'.

In the normal operation of the NEM, this is not a significant problem. NEMMCO has developed arrangements under which generators which are trapped or stranded are informed of this in real time, allowing them to change their bids.

However, trapped and stranded generators may give rise to a problem in the NNC run of the model. In the NNC run, generators may be dispatched for an amount which diverges considerably from their dispatch in the ANC run. A generator may easily become trapped or stranded in the NNC run where they would not be in the ANC run.

As mentioned above, when a generator is trapped or stranded in the normal operation of the NEM, generators have an opportunity to adjust their bids so as to overcome the trapped or stranded constraints. But this raises the question of how such behaviour should be modeled in the NNC run?

One ad hoc approach would be to adopt a heuristic such as the following: if a generator is trapped or stranded for three consecutive intervals in the NNC run, its FCAS trapezium will be automatically re-bid to alleviate these constraints.

However, rather than address these issues, it has been decided that, at this stage, FCAS markets will be ignored. In future refinements of the model it may be possible to incorporate FCAS markets in an acceptable way. Doing so would likely require developing an acceptable heuristic which accurately reflects generators' response to being trapped or stranded.

Why does the proposed approach compute the cost of transmission constraints using generator offer curves? Does it not make more sense to base the calculation on the actual cost of each generator?

To compute the total dispatch cost in the ANC run and the NNC run it is essential to have some idea of the 'cost function' of each generator (at least up to a constant). The proposed approach effectively assumes that the offer curve of each generator is an acceptable approximation of the true marginal cost curve of the generator—so that the area under the marginal cost curve is an acceptable approximation of the true cost of each generator, at least up to a constant.

It is known that there are both pros and cons with this approach. To begin with, in a competitive market each generator has an incentive to bid an offer curve which closely reflects its true marginal cost curve, at least in a region in which the generator expects to be dispatched. Therefore, there is at least some reason to believe that generator offer curves will, in part, reflect their true marginal costs.

However there are known to be circumstances where generators' offer curves will not reflect their true marginal cost. In particular, this arises when either (a) generators have market power or (b) in the presence of intra-regional constraints.

If a generator has market power it will (usually) bid an offer curve which lies above its marginal cost curve. The effect of this behaviour on the TCC will depend on whether this generator is in an exporting region or an importing region. If the generator is located in an exporting region, the exercise of market power will tend to lessen the apparent cost of the transmission constraints. The exercise of market power in an importing region will tend to raise the apparent cost of transmission constraints.

Although it seems likely that the proposed approach to computation of the TCC will be somewhat affected by the presence of market power, it is not yet clear whether this will lead to a systematic bias in the level of the TCC. Further research is needed to understand the effect of market power on the proposed TCC computation.

It is widely known that in the presence of intra-regional constraints, remote intra-regional generators no longer have an incentive to bid an offer curve which reflects their true costs. The reason is that remote intra-regional generators cannot affect the regional reference price. As a result, their bids determine only whether or not they are dispatched—not the price they are paid if they are dispatched. In this circumstance, a generator which is constrained on (that is dispatched at a time when the regional reference price is less than its variable cost) will attempt to bid in such a way as to prevent itself from being dispatched. It may, for example, bid its output at VoLL, or reduce its availability, to prevent being dispatched. Similarly, a generator which is constrained off (that is, which is not dispatched at a time when the regional reference price exceeds its variable cost) will attempt to bid in such a way as to ensure that it is dispatched. It may do this by bidding all of its output at $-1000.

In other words, in the presence of intra-regional constraints remote intra-regional generators are known to have an incentive to submit an offer curve which does not reflect the true costs of operation at that point in time.

These problems will undoubtedly have an impact on the TCC as measured under the proposed approach. But what are the alternative approaches to computing the TCC? Are there other approaches which are clearly preferred?

The primary alternative approach is to simply impose from outside a cost function for each generator. Although the precise cost function of any one generator at a given point in time is largely unknowable, it is often possible to make a rough approximation of the variable cost of a generator. If this were combined with information on the outage rate of the generator it might be possible to come up with a reasonable approximation of the cost function of each generator.

However, there are problems with this approach. In particular, this alternative approach involves a significant exercise of discretion on the part of the AER. The AER would have to make a judgment on the variable cost and capacity of every generator in the NEM, and how that variable changes over time, with changes in the cost of fuels, labour inputs, exchange rates and so on. The AER would also have to make judgments on the likely outage rates of generators and when generators are most likely to take planned outages, and so on. The AER would have to estimate the likely opportunity cost of water for all hydro generators. The resulting TCC measure is likely to be very sensitive to these assumptions.

On balance, at the present time, the AER has decided to pursue an approach which relies on as little discretionary input from the AER as possible. As a result the AER has decided to explore measuring the cost of transmission constraints based virtually entirely on generator offer curves.

However, the AER has decided not to exclude the possibility of substituting its estimate of a generator's costs in those instances where the generator clearly lacks an incentive to bid an offer curve which accurately reflects its costs. For example, experience to date has shown that generators subject to directions or network support agreements may not have an incentive to bid in a way which truthfully reflects their costs. As set out in this decision, the AER has, in these isolated instances substituted an estimate of the generator's marginal cost or removed the impact of that generator entirely.

How have you handled 'fixed-load' constraints?

In the NEM, generators are entitled to specify a fixed level of output at which they will be dispatched. This is known as a 'fixed-load' or 'fixed-loading' bid. Generators are only permitted to use this bid in the event of genuine physical operating constraints which make it infeasible, unsafe, or undesirable to vary output for a period of time. Since these bids reflect physical constraints on generators only, they are, in principle, not related to network constraints. Therefore constraints of this kind are included in both the ANC and the NNC runs.

Note that a generator which bids a fixed load specifies the level of output at which it requires to be held. Under the current approach to computing the TCC, the AER has effectively assumed that this level is an 'absolute' level and not a 'relative' level. In other words, a generator who happens to be producing 400 MW and bids fixed-load at 400 MW is assumed to be announcing that it wishes to remain at 400 MW, not that it wishes to remain at the current level of output.

This distinction is important in applying these bids in the NNC run. The same generator may be dispatched at a much higher or lower amount in the NNC run. Under the current approach, following a bid of fixed-load at 400 MW that generator will be moved to 400 MW whatever its current level of output.

Fixed-load bids are retained in both the ANC and the NNC runs while ramp rate bids are ignored in both.

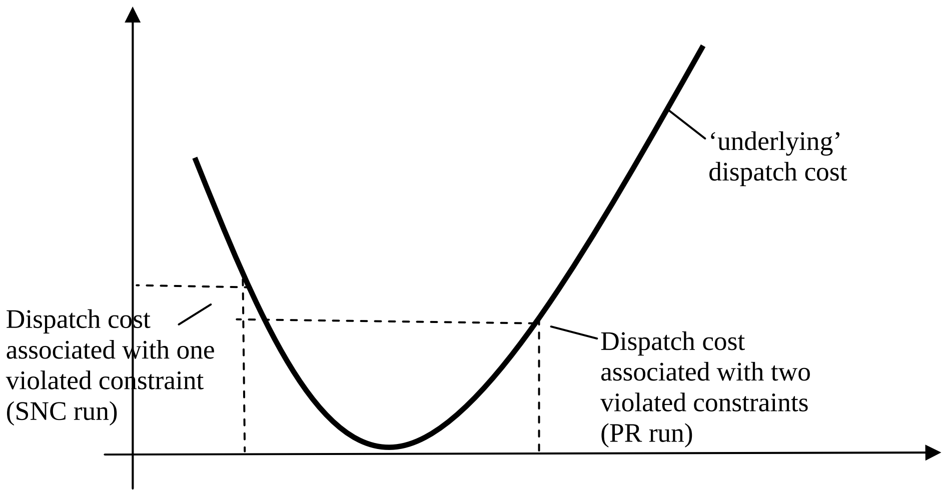
Why is the OCC measure sometimes negative?

As mentioned earlier, the AER is also proposing to compute the cost of 'outage' constraints by comparing the dispatch cost in the PR run with the dispatch cost in a run which includes only SNC. The resulting measure of outage constraint costs is referred to as the OCC.

Under normal circumstances, we would expect that the OCC would be non-negative. It should be zero when no outage constraints are binding and positive when at least one outage constraint is binding. However, experience has shown that on rare occasions the OCC can be negative.

The reason for the negative values of the OCC seem to relate to the presence of violated constraints. Recall that a violated constraint is assigned an impact on the NEMDE objective function of many times VoLL. In effect, this instructs the NEM dispatch engine to give greater priority to these constraints over all other constraints. The dispatch engine will seek to reduce such violations largely irrespective of the impact that reducing such a violation will have on the underlying dispatch cost.

The negative OCC seems to arise when there are at least two violated constraints in the PR run and one of those constraints is not violated constraint in the SNC run. Intuitively it seems that in the event that there are two violated constraints the violation penalties may be 'pulling in opposite directions'. Relaxing one of them may lead to a higher (rather than lower) underlying dispatch cost and therefore a negative TCC. This is illustrated in the following diagram:



This outcome cannot arise in the TCC calculation since the TCC calculation involves relaxing all the network constraints (there cannot remain any violated network constraints in the NNC run). It also cannot arise in the OCC calculation in intervals where only outage constraints are violated (for the same reason).

Currently it appears that this problem does not occur often enough to be a serious issue. However, this will need to be kept under review.

What about generators which are dispatched for more than their declared availability?

On rare occasions are generator in the NEM is dispatched to a dispatch target which is in excess of the smaller of its declared maximum availability (MAXAVAIL) and the sum of the quantities offered in its offer bands. These cases only arise when constraints must be violated to prevent, say, load shedding. In these instances it was determined that this extra generation should be valued at VoLL.

Appendix C : MCC calculation

The MCC is a market impact indicator of transmission constraints based on the marginal value of constraint equations.

NEMDE (the dispatch engine) is a linear program that dispatches the market to maximise the value of spot market trading subject to inter and intra-regional network limitations.[14] Each physical network limitation is represented to NEMDE as a mathematical equation, known as a constraint equation. Most of these constraint equations have no impact on dispatch and have an associated ‘marginal value’ of zero. When a constraint equation has an impact on dispatch, the associated marginal value is positive. The marginal value is an indication of the change, at the margin, in the cost of producing electricity sufficient to meet demand brought about by a particular constraint.

The marginal value is equivalent to the difference between the marginal generation offer at the location where generation must be increased and the marginal generation offer at the location where generation must be decreased. If the constraint is an inter-regional constraint, the marginal value usually equals the difference between the marginal generation offer in the importing region and the marginal generation offer in the exporting region. That is, the marginal value is the price difference between the two regions. For constraints classified as relating to network limitations within a region (or an intra-regional constraint), the marginal value is, usually equivalent to the difference between the marginal generation at the regional reference node (setting the price in that region) and the marginal offer price of the generator impacted by the constraint.

That is, broadly, inter-regional constraint marginal value =

price in importing region – price in exporting region

and, intra-regional constraint marginal value =

regional price – constrained generation marginal price

The marginal values for inter and intra-regional constraints are therefore quite different in nature. The inter-regional constraint marginal value is a relatively high quality indicator of the market impact of the constraint, albeit at the margin, as the pricing outcomes in each region are reflected in actual market settlement outcomes. In the case of intra-regional constraints the marginal value may have little or no meaning. For example when a generator is constrained-off by a network restriction, generators often bid at the price floor of $-1000/MWh, which can lead to large marginal values. Market settlement is, however, settled on the regional price and not the negative offer price. For this reason, the assessments of inter-regional and intra-

[14] There are a number of other types of constraints, including: to manage the frequency control ancillary service (FCAS) market: to implement power system directions; to manage grid support; and to manage the accumulation of negative inter-regional settlements residue.

regional constraints differ. Both types of constraints, when binding, affect market outcomes. In prioritising those constraints with the largest market impacts and therefore requiring a qualitative assessment, we have selected inter-regional with high cumulative marginal values (CMV) and intra-regional constraints that bind often.

The differences in the marginal values for intra-regional and inter-regional constraints have resulted in different thresholds that the AER will apply in examining constraints in its qualitative assessment. The threshold for further assessment of inter-regional constraints is a cumulative marginal value for the year, in the 2003–04 report this was a threshold of $30 000/MW.

The threshold for intra-regional constraints will be set based on the amount of time the constraints bound. In the 2003–04 report constraints that bound for more than 10 hours were examined in the qualitative assessment.

Marginal values can be influenced by factors that lead to published marginal values that are significantly larger than the price cap of $10 000/MWh. This is not immediately intuitive. The following describes some of the conditions that lead to these outcomes, and where it was deemed appropriate, how those marginal values have been modified.

C.1 Constraint violation penalties

The major issue in using the marginal values that NEMDE produces is how network constraint violations are treated. The constraint equations can be thought of as the defined solution space in which NEMDE must solve. In some instances a solution space can not be defined without violating one or more network constraint equations.

In the case where a constraint equation must be violated NEMDE decides which one(s) to violate with reference to constraint violation penalties. Constraint violation penalties are assigned to constraint equations in a priority order determined by NEMMCO so that some constraints are violated before others.

When a constraint must be violated, the objective function includes a cost of violating the constraint equation, which is equal to:

violation penalty x violation degree x VoLL

Where:

violation penalty: is a penalty assigned to every constraint equation and typically ranges between 20 and 360.

violation degree: is the amount by which the constraint equation is violated in mega watts (MW).

VoLL: is the value of lost load, which is $10 000/MWh.

To calculate the marginal value, NEMDE considers the change in the objective function when relaxing the constraint by a notional unit of energy. Therefore if that constraint was violated, the marginal value would assess the cost of reducing the violation degree by that one unit.

The marginal value is the change in the objective function, which can be considered (in this simple case) as:

the change in (violation penalty x violation degree x VoLL)

For example:

violation penalty: = 360

violation degree: = 40MW

VoLL: = $10 000/MWh

In this case, the violation of this constraint would contribute $144 000 000 (=360 x 40 x 10 000) to the objective function. The marginal value would then look at increasing the capacity of the transmission line such that the violation required would only be 39MW. This would contribute $140 400 000 (=360 x 39 x 10 000) to the objective function.

While there might be other changes to the objective function, it can be seen that this violation would add $3 600 000 to the objective function. It can also be shown that this is equal to the violation penalty multiplied by VoLL.

These constraint violation penalties do not relate to a pricing decision by a participant and as such should not interfere with pricing outcomes, except through the impacts they have on the dispatch of generation. However, in some instances violated constraints do interfere with the pricing for a dispatch interval. In these instances NEMMCO has a technique to reveal the true energy price.[15] The AER has adopted, with some modifications, this technique to remove the impacts on violations in the MCC calculations.

There is a second order problem caused by constraint violation penalties, which is discussed here for completeness. This second order problem is that a violated constraint equation with a high marginal value may cause high marginal values for other constraint equations.

On certain occasions there may be one or more constraint equation(s) that cannot be satisfied, which requires, at least, one of the constraint equations to be violated. When a constraint equation is violated the objective function is influenced by the amount of the violation, the violation penalty and VoLL.

In some situations a constraint equation, although not violated, can directly influence the amount by which a second constraint equation is violated. When this situation occurs a marginal change in the first constraint equation's RHS will then result in a

15 *Determination report—National Electricity Market, pricing during over-constrained dispatch,* NEMMCO, 21 August 1998 (see www.nemmco.com.au/dispatchandpricing/525.htm).

reduction in the violation of the second constraint equation. Therefore the marginal value of the first constraint equation (which was not violated) depends on the constraint violation of the second constraint equation (which was violated).

For example, consider a case where there are two constraints (constraint A and constraint B). Constraint A and constraint B cannot both be satisfied. Constraint A has a violation penalty of 20 and constraint B has a violation penalty of 360, which means constraint B is less likely to be violated.

To illustrate this example assume that invoking constraint B results in constraint A being violated by 10MW, which contributes the following amount to the objective function:

= violation degree x violation penalty x VoLL

= 10 x 20 x 10 000

= 2 000 000

To measure the marginal value of constraint B, its RHS is conceptually relaxed by one megawatt. This has the effect of reducing the amount that constraint A is violated from 10MW to 9MW.

The objective function is then reduced by, at least, the change in the violation penalty imposed on constraint A, which is:

= (9 x 20 x 10 000) – (10 x 20 x 10 000)

= -200 000

Therefore the marginal value of constraint B, which was not violated, is reported as 200 000, as a result of the violation forced on constraint A.

C.2 Adjusting for constraint violation penalties

When constraint violations occur the marginal values represent the mathematics of dispatching the market, rather than actual outcomes in the market. Therefore the AER adjusted the marginal values to ensure consistent treatment of all constraints.

When NEMDE violates a constraint equation the solution variables (the LHS terms) will be set so that the constraint equation will not be satisfied. The LHS of the constraint equation has control variables and the RHS determines the limit. The following is the same example constraint equation used in section C.3:

$$LHS \leq RHS$$

$$1xG_1 - 0.5xG_2 \leq 400$$

The constraint will not be satisfied if $G_1 = 450$ and $G_2 = 50$. In this situation, G_1 cannot reduce its output below 450MW because of other constraints, and assume G_2 has a limit of 50MW on its maximum output. The constraint can no longer be satisfied. In this case the LHS will be 425 and exceeds the RHS by 25. This excess is known as the violation degree.

If the constraint equation was re-written, for this particular dispatch interval, with a RHS of 425, then:

- the same dispatch outcomes for generation would occur
- the constraint would still bind
- the marginal value may still be affected by the constraint violation penalty.

To prevent the constraint from binding and the violation penalty from affecting the marginal value the RHS should be set to 425 plus a small amount, so the constraint does not bind.

This is the same method that NEMMCO uses when a regional price is set by over constrained dispatch.[16]

In practice the AER relaxed the RHS of violated constraints by the violation degree plus 0.01. These modified constraint equations were substituted for the original constraint equations in the NEMDE input files—the files provided to the dispatch algorithm. These alternative input files were then submitted to NEMDE for a dispatch solution. The marginal values that were produced reflect the value, as measured by the change in the dispatch cost of generation, of the constraint rather than the constraint violation penalty.

C.3 Scaling factors

When a binding constraint is relaxed the dispatch of generation is changed to find a more optimal solution. In this case, scaling factors that are used in constraint equations can cause high marginal values.

Table 3–Example of scaling factors

Generator	**G_1**	**G_2**	**G_3**
Offer price ($/MWh)	n/a	10 000	100
Output for RHS = 400 (MW)	450	100	100
Output for RHS = 401 (MW)	450	98	102

The following example illustrates how scaling factors used in constraint equations can cause high marginal values.

16 ibid.

Consider a constraint equation where two generators' output levels are restricted by a network limit:

$$LHS \leq RHS$$

$$1xG_1 - 0.5xG_2 \leq 400$$

Where:

$1xG_1$: is the scaling factor (1) multiplied by the output of generator one

$-0.5xG_2$: is the scaling factor (-0.5) multiplied by the output of generator two

In this example NEMDE would consider all constraint equations and the objective function to find the most optimal solution. To best illustrate this example the following have been assumed to be part of the optimal solution:

- The regional reference price is \$100/MWh and is set by generator three (G_3). G_3 is known as the 'price setter' and is dispatched to provide 100MW.
- G_1 is constrained at 450MW through other constraints and cannot be changed at any cost.
- G_2 is then constrained at a minimum output of 100MW. G_1 is constrained at 450MW. Therefore the constraint equation is satisfied and the network security is maintained:

$$1x450 - 0.5x100 \leq 400$$

To calculate the marginal value for this example, NEMDE would relax the constraint equation such that its RHS is marginally increased. This marginal increase can be considered to be an increase from 400 to 401. Conceptually, the constraint equation would change to:

$$1xG_1 - 0.5xG_2 \leq 401$$

NEMDE would then determine the most optimal solution for this conceptual change, while all other constraint equations remained unchanged. In determining the optimal solution the dispatch of G_1 would remain at 450MW because it was constrained at that level by other constraints that have not changed. The dispatch of G_2 would decrease from 100MW to 98MW, which would ensure the changed constraint equation is satisfied, as follows:

$$1x450 - 0.5x98 \leq 401$$

This 2MW change in the output of G_2 would also be reflected in the objective function. The objective function value would change by the change in each generators output multiplied by its respective offer price. This example assumes G_2 offered its capacity at \$10 000/MWh. Therefore the change in the objective function value that would result due to the change in the output of G_2 would be:

= increase in the output of G_2 x offer/bid price of G_2

$$= -2\text{MW} \times \$10\,000/\text{MWh}$$

$$= -20\,000$$

However, this is not the total change to the objective function. If the output of G_2 was reduced by 2MW, then that 2MW must be supplied by another generator.[17] Therefore an increase of 2MW of capacity is required to be supplied by the price setter, G_3. The total change in the objective function is:

$$= (2 \times 100) - (2 \times 10\,000)$$

$$= -19\,800$$

The marginal value for the example above is $19 800. This shows that marginal values exceeding $10 000 can represent outcomes of dispatch rather than mathematical outcomes such as those created by constraint violation penalties

[17] The amount of capacity required to may not be 2MW depending on scaling factors, losses and any change to demand contingent on price. A 2MW requirement is assumed to illustrate the example.