Better regulation

Consumer reference group–issues paper

February 2013

AUSTRALIAN
ENERGY
REGULATOR

Contents

Overview

The AER is implementing the rule changes to the National Electricity Rules (NER) and National Gas Rules (NGR) that were published by the Australian Energy Market Commission (AEMC) on 29 November 2012. This is through the 'Better regulation' program which is to deliver an improved regulatory framework focused on promoting the long term interests of electricity consumers.

Better regulation

As part of the Better regulation program, we will develop our approach to regulation under the new framework over the next 12 months. This will be achieved through several work streams and will culminate in the development of several guidelines. We will develop the guidelines through consultation with key stakeholders, including consumers and network businesses. The proposed guidelines to be developed under the revised approach include:

Expenditure Forecast Assessment Guidelines—Assessing expenditure proposals from businesses

Rate of Return Guidelines—Determining the allowed rate of return businesses earn on their investments.

Expenditure Incentives Guidelines—Creating the right incentives to encourage efficient spending by businesses.

Service provider consumer engagement guideline—Implementing consumer engagement strategies that are effective for all stakeholders.

Shared Asset Guidelines—Sharing the revenue networks earn from shared assets with consumers.

Power of choice implementation—Ensuring network companies are innovating and exploring demand management solutions.

Confidentiality Guidelines—Managing confidential information for an effective regulatory determination process.

Consumer reference group

The consumer reference group (CRG) is established by the AER to facilitate consumer input into the Better regulation program. The Better regulation program encompasses the development of the AER's guidelines as set out under the NER and an additional guideline on Service Provider Consumer Engagement.

We want to ensure our communication and regulatory strategies meet the needs of energy consumers. We are keen for consumers and their representatives to participate in the development of these guidelines. Participation in the CRG will allow members to inform us about issues that impact them. The intention of the CRG is to make it easier for consumer representative groups to have input into the Better regulation consultative process without necessarily writing formal submissions. CRG members are able to distil key issues and information to constituents for consideration, consult and report back to the AER. This will provide a mechanism for co-ordinated and informed input from a cross–section of consumer groups. The CRG will also give guidance on where consumer representative groups can invest their limited resources to contribute most effectively to future regulatory processes.

Issues paper

The purpose of this issues paper is to provide CRG members with issues that will allow CRG members to engage effectively with the development of the guidelines and provide meaningful contributions to this process. As we engage with stakeholders on the Better regulation program it is likely that the issues within each work stream may change.

Meeting information

We anticipate holding CRG meetings monthly, until the Better regulation program has concluded. Meetings will run for approximately 2–3 hours.

We will make video conference facilities available, where possible, from the nearest ACCC/AER offices. CRG members will be required to meet their own travel, accommodation or associated expenses.

The meeting dates include:

- 14 March — 9.00am to 12.00pm
- 24 April —2.00pm to 4.30pm
- 23 May — 1.00pm to 3.30pm
- 20 June — 10.00am to 12.30pm

1 Introduction

The Better regulation program seeks to develop our approach to regulation. Our primary regulatory responsibility is to determine the revenues of transmission network service providers (TNSPs) and distribution network service providers (DNSPs)—collectively referred to as network service providers (NSPs)—operating in the National Electricity Market (NEM). Generally, this means that we must make a revenue determination for NSPs every five years to determine how much revenue NSPs can recover from their customers.

1.1 Legal context

The National Electricity Law (NEL) and the NER provide the framework under which we operate.

The NEL contains two overarching principles that we must apply when performing our economic regulatory functions or powers. Under section 16(1)(a) of the NEL we must act in a manner that will or is likely to contribute to the achievement of the national electricity objective (NEO). The NEO is set out in section 7 of the NEL:

> The objective of this law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interest of consumers of electricity with respect to –
>
> a) price, quality, safety, reliability and security of supply of electricity; and
>
> b) the reliability, safety and security of the national electricity system.

We must also take into account the revenue and pricing principles when exercising its discretion in making a transmission determination. The revenue and pricing principles are set out in section 7A of the NEL. In short, the revenue and pricing principles require a NSP to be provided with an opportunity to recover at least its efficient costs, while being provided with incentives to promote economic efficiency.

Chapters 6 and 6A of the NER provide for the economic regulation of DNSPs and TNSPs respectively. These chapters stipulate that we must make decisions on how we will regulate distribution and transmission services.

Our determinations must meet the requirements under the NEL and NER. The NER sets out certain objectives for NSP forecasts of total capital expenditure (capex) and operating expenditure (opex) (which are used in determining revenues). These objectives are to:

- meet or manage expected demand
- comply with regulatory obligations or requirements
- maintain the quality, reliability and security of supply
- maintain the reliability, safety and security of the network.[1]

We must determine whether the forecasts of capex and opex are required to achieve these objectives. We must also consider whether the expenditure reasonably reflects the efficient costs that

1 NER, clauses 6.5.6(a), 6.5.7(a), 6A.6.6(a), 6A.6.7(a).

a prudent operator in the NSP's circumstances would need to incur, based on a realistic expectation of demand and cost inputs required to achieve these objectives.[2]

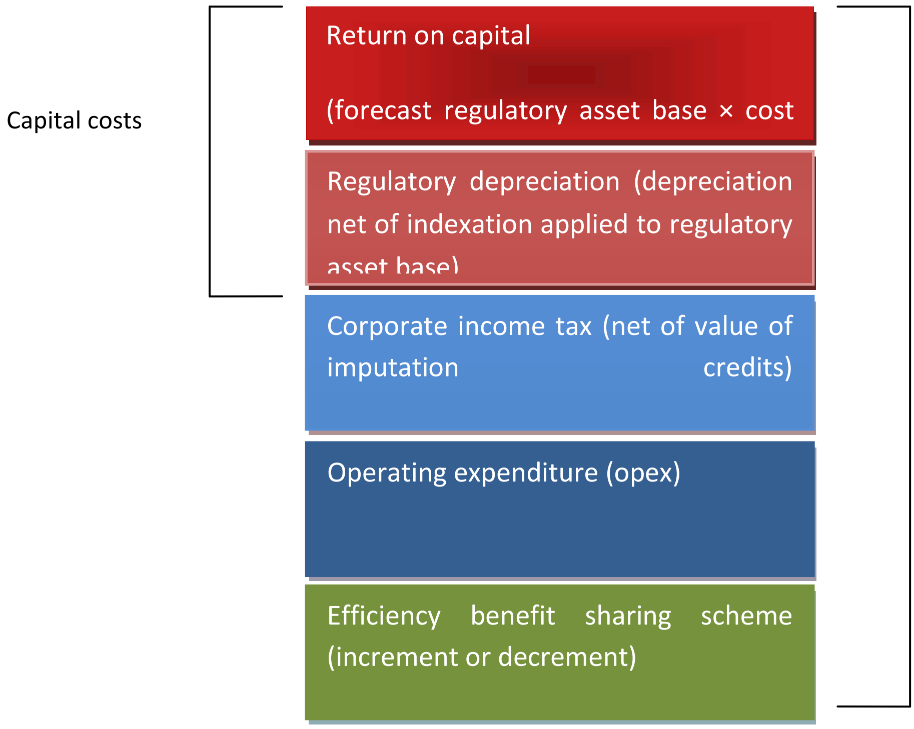
1.2 Building block approach

The NER requires us to use the building block approach to determine revenues. The revenues that we allow are built up from the following costs related to the operation of electricity networks:

- a return on the regulatory asset base (return on capital)
- depreciation of the regulatory asset base (return of capital)
- the estimated cost of corporate income tax.
- forecast opex
- increments or decrements resulting from the efficiency benefit sharing scheme (EBSS)[3]

Figure 1 illustrates the building block approach. Importantly, the return on capital and the return of capital are dependent on the NSP's asset base and forecast capex.

Figure 1: The building block approach for determining total revenue



1.3 Stakeholder input

The review process that we undertake when making a revenue determination is comprised of several stages. These include the consideration of a NSP's revenue proposal and submissions on the proposal from other stakeholders, making of the draft decision, consideration of a revised revenue proposal, further consultation and the making of the final decision and transmission determination.

2 NER, clauses 6.5.6(c), 6.5.7(c), 6A.6.6(c), 6A.6.7(c).
3 NER, clauses 6.4.3(a), 6A.5.4(a).

Submissions from interested parties are an important part of our review process. As noted we operate within this legal framework. Submissions are effective when they provide information, data and commentary on issues that sit with this legal framework. Submissions are more effective when they address specific issues rather than discuss general concerns.

2 Expenditure forecast assessment

We are responsible for reviewing and approving the capex and opex forecasts of the transmission and distribution businesses. Forecast capex is a forecast of the cost of new assets that are likely to be required by a network business during a regulatory control period for the efficient operation of the network. Forecast capex is an input into the return on capital building block and the return of capital building block.

Forecast opex is one of the building blocks. It is a forecast of the operating, maintenance and other non–capital costs incurred by the NSP. Opex includes labour costs and other non–capital costs.

We are required to publish the Expenditure Forecast Assessment Guidelines for transmission and distribution businesses by 29 November 2013.[4] This guideline will describe the techniques and associated data requirements for our approach to determining efficient capex and opex allowances in accordance with the objectives, criteria and factors in the NER.

The assessment techniques and data requirements outlined in the guideline will also form the basis of annual benchmarking reports, which we are now required to publish under the NER.[5]

2.1 Issues of interest regarding expenditure forecast assessment

On the whole, we will be looking to improve our approach to expenditure assessment and become better equipped to challenge and critically analyse the proposals put to us by regulated networks. Below are some issues we consider that CRG members will most effectively be able to engage with in the development of the Expenditure Forecast Assessment Guidelines and provide meaningful contributions to this process.

2.1.1 Benchmarking reports

A key feature of this work stream is the development of benchmarking techniques. Benchmarking is the process of comparing one NSP's processes and performance to other NSPs. Benchmarking has been a relatively underdeveloped area of analysis in our decisions and one which we expect will deliver a more effective approach than relying largely on detailed, 'bottom-up' assessments.

We will also utilise the benchmark reports to better inform consumers of the cost and performance of the regulated businesses on an annual basis.

The first benchmarking report must be published by 30 September 2014 and the second by 30 November 2015, with subsequent reports published at least every 12 months thereafter.

These reports will add to our existing publication of network performance data and provide important information for all stakeholders when discussing the efficient expenditure allowances set in transmission and distribution determinations. For this reason we will be largely guided by stakeholder feedback on what information they would find useful to receive on an annual basis, including the level of detail and technicality at which we should be reporting.

Similarly, we will be interested in views regarding the types of supporting information that should be published (or provided on request) alongside benchmarking reports and network determinations.

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4 NER, clauses 6.4.5(a) and 6A.5.6(a) require that we publish the Guidelines. Transitional rules 11.53.4 and 11.54.4 set the date for their publication.

5 NER, clauses 6.4.5(a) and 6A.5.6(a) require that we publish the Guidelines.

We expect that establishing consistent expenditure reporting definitions and a benchmarking framework will involve significant effort and cost for some network businesses. As part of standard regulatory practice, we will need to justify the collection of this information in light of the expected benefits.

Issues Box 1

- What types of information do consumers find most valuable and how would it be used?

- How do consumers feel about the level of detail contained in the benchmarking reports?

- Are consumers more concerned about consistency or flexibility in reporting?

2.1.2 Principles and objectives of the expenditure forecast assessment guidelines

In developing and implementing the guidelines we will be mindful of consumer interests as articulated in the NEO and in the revenue and pricing principles.

In particular we will be taking a long term perspective, recognising consumer interests in terms of price impacts as well as on service delivery and network security arising from under and over investment. We may also take into account explicit customer preferences to smooth out or defer expenditure programs in order to minimise price shocks, with proper recognition of any short term risks this may bring.

We will be seeking stakeholder feedback on whether these, and other principles or objectives, should be specified in the Guidelines, or whether existing NER provisions will be sufficient to guide our assessment approach.

Details to be contained in the Expenditure Forecast Assessment Guidelines

The NER sets out that the Expenditure Forecast Assessment Guidelines will contain the techniques and data requirements of the AER for undertaking assessments of efficient capex and opex. However, they will be given effect by information templates and instruments issued under the NEL. This may create some overlap between the information gathering instruments and the guidelines. Alternatively, the guidelines could describe in general terms the data required.

Flexibility in the information templates and guidelines will allow us to respond more readily to changing network and consumer requirements. Further, consistency in these documents will provide a greater level of stability to network businesses. We are seeking consumer views on the appropriate balance in this area.

2.1.3 Timing of issues and deliverables

We published an issues paper in December 2012; from there:

- Consultation—closes 15 March 2013
- Draft Expenditure Forecast Assessment Guidelines released—9 August 2013
- Consultation on the draft Expenditure Forecast Assessment Guidelines—August/September 2013
- Final Expenditure Forecast Assessment Guidelines—29 November 2013.

3 Rate of return

The Rate of Return Guidelines will set out how we intend to apply the new rules framework to set rates of return for network businesses that meet the long term interest of customers. This will involve setting out high level regulatory principles that will guide our assessment of methodologies, data sources and models to determine returns on equity and debt that make up the overall rate of return.

3.1 What is the rate of return?

The rate of return is an input to the building block approach that we use to determine total revenue for each regulatory year of the regulatory control period. The rate of return is to be commensurate with prevailing conditions in the market for funds and the risks involved in providing relevant services.[6]

We calculate a return on capital building block by multiplying the rate of return with the value of the NSP's projected capital base. Consistent with previous decisions, we will adopt a rate of return that is based on a nominal vanilla weighted average cost of capital (WACC) formulation.

Below are some issues that we consider that CRG members will most effectively engage with the development of the rate of return guideline and provide meaningful contributions to this process.

3.1.1 Setting of discount rates in the real world

When assessing whether to invest in a project or not, large regulated utilities assess whether a particular project's expected return is greater than the required rate of return.

3.1.2 Value of the weighted average cost of capital

The weighted average cost of capital refers to the process of estimating the appropriate return on debt and of equity, and then combining them (using a 'weighted average') to form an overall return that will incentivise the network business to make efficient investments.

Broadly, there are two types of investments–debt and equity. Debt is when investors loan money to the business, with a predetermined agreement on when they will be repaid, and how much they will be repaid (the original investment plus interest). The interest charged on the loan is the return on debt by way of compensation for providing the initial capital invested.

Equity is when investors own a portion of the business, and therefore there is no predetermined repayment date. There is less certainty about how much they will earn on their investment. The equity holder is often called a shareholder, and the return on capital they receive (or, more specifically, the return on equity) is usually in the form of dividends or capital gains.

3.1.3 Issues

Issues Box 2

- Flexibility or certainty. Can consumers express a view about which is more preferable. If certainty is important, is 'certainty of process' or 'certainty of outcome' to be the main driver of rate of return decisions? Are consumer groups comfortable with a less mechanistic approach to estimating the rate of return, and leaving judgment to the regulator?

6 NER, clauses 6.5.2(c), 6A.6.2(c).

- Are smooth/stable electricity and gas prices more important to customers than fluctuations in prices. Context - financial markets fluctuate, which can result in the rate of return moving up or down sharply from one determination to the next. This potentially can be smoothed out through the use of long term averages for say, estimating the cost of debt.

- What levels of risk are consumers prepared to accept form their network service provider? Is the relativity between the rate of return expected from CRG members businesses and those of monopoly network service providers regarded as appropriate? Are there specific risk factors that we should take into account?

3.1.4 Timing of issues and deliverables

We published an issues paper in December 2012; consultation on that paper will close 15 February 2013. From there:

- Consultation paper released—29 March 2013
- Consultation—April 2013
- Draft Rate of Return Guidelines released—9 August 2013
- Consultation on the draft Rate of Return Guidelines—August/September 2013
- Final Rate of Return Guidelines—29 November 2013.

4 Expenditure incentives

The NER requires us to develop the Capital Expenditure Incentive Guidelines.[7] The Capital Expenditure Incentive Guidelines will set out how we intend to apply improved incentives for electricity network businesses to incur efficient capex. This is so that only investment that is necessary to provide a safe and reliable network is funded by consumers.

In addition, we will be reviewing the incentives for efficient opex. We will consider whether revisions are required to the current efficiency benefit sharing scheme (EBSS) that applies to network businesses. This review will also consider our approach to the expenditure assessments of network businesses described in section 2 (above).

4.1 Current incentive-based regulation

The economic regulatory framework for network businesses is based on the concept of ‘incentive regulation’ which seeks to provide strong incentives for regulated businesses to reduce costs, improve service quality, and undertake efficient investment. The incentive to reduce costs is provided by the regulator setting the prices or revenue (based on efficient investment) to apply at the start of the regulatory period, regardless of what actual costs are incurred during the regulatory period. Regulated businesses that realise efficiency gains can retain these benefits for a time, and the benefits are later shared with customers in the form of lower prices.

The 'revealed cost' approach is a key feature of the regulatory framework, when incentives are effective in promoting efficient outcomes. In such cases, the NSP's actual costs, as revealed through regulatory accounts, are taken to be the ‘efficient’ costs and become the starting point for assessing the needs of the business to provide services in the forthcoming regulatory period. In this way, efficiency gains that the businesses have made are passed back to consumers in the form of lower prices.

Although this is a key starting point for our assessment of the expenditure forecasts in revenue determinations, we make adjustments to the regulated allowances to take account of changing circumstances that are likely to apply in the forthcoming period. These include:

- the extent of asset replacement required to deal with an ageing asset base
- the need for new assets to meet continuing growth in demand and customers numbers
- changes in financing costs
- input costs and meeting reliability
- safety and other service obligations.

It should be noted, however, that, where businesses have not adequately responded to the incentives provided or where the network business’ proposal points to changes in forecasts which are not otherwise justified, we cannot solely rely on revealed costs and would still need to use other comparative benchmarking approaches. It is against this background that we are considering appropriate expenditure incentives.

7 NER, clauses 6.4A(b), 6A.5A(b).

Other incentives to maintain or improve service quality levels work in combination with efficiency incentives to ensure that improved efficiency is not at the expense of service quality. Overall, the regulatory framework seeks to provide appropriate signals for regulated businesses to make efficient investments and not over or under invest in the network.

4.2 Strengthening capital expenditure incentives

The Capital Expenditure Incentive Guidelines will cover a number of mechanisms and approaches that, taken together, should:

- improve incentives for electricity businesses to undertake efficient capex
- safeguard consumers from paying prices that reflect inefficiently incurred capex.

In particular, the guidelines will cover:

- the type of capex sharing scheme/s that will apply to strengthen the incentives for network businesses to incur only efficient expenditure and in what circumstances these may be applied
- the form of ex post review/s that will apply to reviewing past capex for efficiency and the relevant circumstances in which an ex-post review of capex may occur
- how we will determine whether to use actual or forecast depreciation to roll forward the regulatory asset base at the start of a regulatory period
- how we will assess whether related party margins for network costs provided by a related entity to the service provider were efficient and whether these should be included in the regulatory asset base
- in terms of capitalisation policy changes, how we will assess whether to roll into the regulatory asset base any expenditure that was previously classified as opex at the time of our determination.

4.3 Issues

Issues Box 3

This work stream will be discussed at the 14 March CRG meeting.

4.4 Timing of issues and deliverables

- Issues paper released—March 2013
- Consultation—May 2013
- Draft Capital Expenditure Incentive Guidelines released—9 August 2013
- Consultation on the draft Capital Expenditure Incentive Guidelines—August/September 2013
- Final Capital Expenditure Incentive Guidelines—29 November 2013.

5 Shared assets

We must publish the Shared Assets Guidelines.[8] This may allow electricity customers to benefit from unregulated revenue streams from services provided by regulated assets.

5.1 What are shared assets?

Shared assets are electricity network assets used to provide standard control services. The most common shared assets are also used to provide unregulated services. Examples of shared assets include telephone lines or cable TV lines strung on power poles, use of electricity network easements, mobile phone towers on transmission towers and radio frequency bandwidth otherwise used for electricity network communications. New shared asset provisions in the NER allow us to account for these unregulated services.

We may reduce the proportion of asset costs recovered from electricity consumers, recognising such costs are already partially recovered from unregulated service customers. Electricity prices will be lower than otherwise because fewer costs will be recovered from electricity consumers.

5.2 Issues

The NER establishes only a high level framework for shared asset cost adjustments. The Shared Assets Guidelines may establish key methodological details for us to follow.

Issues Box 4

- What is the appropriate basis for shared asset cost adjustments? This may be the technical use of shared assets for regulated and unregulated services, the proportion of regulated and unregulated revenues gained from shared asset use, or something else.

- What is the best approach to cost adjustment proportions? Once a basis for shared asset cost adjustments is determined, adjustments may be made in a fixed or variable proportion. We will be bound by the guidelines if it sets out that adjustments are made in a fixed proportion. Alternatively, the guidelines may allow us discretion to vary cost recovery proportions according to the circumstances.

- What should the definition of 'material' be in the shared assets context? The NER requires shared asset cost reductions to apply where the use of an asset for services other than standard control services is 'material'. The NER does not define 'material' in the context of shared assets.

5.3 Timing of issues and deliverables

- Issues paper released—March 2013
- Consultation—May 2013
- Draft Shared Assets Guidelines released—9 August 2013
- Consultation on the draft Shared Assets Guidelines—August/September 2013
- Final Shared Assets Guidelines—29 November 2013.

[8] NER, clauses 6.4.4(d), 6A.5.5(d).

6 Power of Choice and demand management related issues

The AEMC has been undertaking a number of reviews into how the National Electricity Market can better support efficient demand-side participation. The AEMC completed its Power of Choice report in November 2012 and is soon to complete its review of energy market arrangements for electric and natural gas vehicles. These reviews propose a number of recommendations to the Standing Council on Energy and Resources (SCER) on required changes to the NER and broader market reforms. The rule change assessment and public consultation processes is likely to begin in 2013. We will have a role in implementing a number of these reforms. This role is likely to involve:

- reviewing incentives for distributors to engage in demand side activities
- reviewing arrangements pertaining to distribution tariff reviews
- possible amendments to our retail guidelines.

6.1 Demand management related issues

6.1.1 What is demand management?

Demand management involves the use of various means to manage customer demand for electricity. Such initiatives often include energy saving projects that may defer the timing of network augmentations.

Each component of the electricity network has limits on the amount of energy it can pass through at any one time. The engineers in the network businesses are able to look at the energy flows on the network and assess when the general growth in usage will reach the capacity limits. Traditionally engineers will then plan to build more infrastructure to increase the capacity of the network. This is typically a new or upgraded line or transformer.

Why demand management?

If customers are able to reduce peak usage or shift load to a different time, then it may be possible to defer the need to upgrade the network. The deferral of a project can represent significant savings to the businesses and the network. The amount of savings depends on the length of the deferral and the value of the deferral. Examples of typical demand management projects that can defer upgrading the network includes:

- cycling an air-conditioner off for short periods of time (peak reduction)
- installing solar panels or Solar hot water (general usage reduction)
- replacing standard incandescent lights with compact fluorescents (general)
- installing movement controlled lighting (general)
- installing energy efficient heating, cooling, insulation, motors, compressors, or ventilation (peak/general)
- switching to onsite generation - emergency backup or cogen (peak)
- installing a generator specifically to “top up” the network as peak times (peak)

- switching off non-essential load at peak times (peak).

Trials and programs across Australia have shown that demand management can and does produce more efficient outcomes. However demand management has not been embraced by all the network businesses and there are a number of reasons for this. Some of these are technical, others commercial and economic.

Technical challenges

- Some of the above examples are specifically targeted at peak times and require communication and verification of the reduction.

- The network peak times are typically weather dependent, difficult to predict and may vary with little notice

- Large customer programs like efficient lighting are not contractible. It relies on faith that the measure will be left in place and operating for the deferred period

- Network engineers are typically "*more comfortable*" with a solution that they can control (i.e. build a new line/transformer) rather than relying on a third party to act. There are also contractual difficulties if the demand reduction provider doesn't deliver and an outage occurs (e.g. who bears the GSL and STPIS costs?).

Demand management incentive scheme

The Power of Choice report recommended changes to the Demand Management and Embedded Generation Connection Incentive Scheme (DMEGCIS). This scheme has the objective of providing an incentive for distributors to implement efficient non-network alternatives. The changes will be implemented by a rule change proposal to be submitted to the AEMC. At this stage, the timing of such rule change is uncertain. However, we do have the role of implementing a DMEGCIS for the upcoming NSW/ACT distribution determination 2014–19. Public consultation will occur as part of this process.

6.2 Pricing reforms

The Power of Choice report sets out a range of issues that currently prevent flexible pricing from being offered to residential and small business customers. A number of initiatives will be undertaken to assist the gradual phasing in of flexible pricing options, taking into account the needs of vulnerable consumers.

The Power of Choice report identifies the introduction of efficient (peak cost reflective) and flexible (time-varying) network tariffs as a key element of the reform package. These recommendations are designed to empower and reward energy consumers to make efficient consumption decisions, particularly at times of peak demand.

The Power of Choice report recommends that pricing reforms should include:

- A framework for competition in metering and data services. This should specify the circumstances in which advanced metering should be installed for example, in households where energy consumption exceeds a specified threshold.

- The phase in of efficient and flexible network tariffs for different categories of consumers. For instance:

- Efficient tariffs should be compulsory for large residential consumers and small business consumers.
- Efficient tariffs should be the default option for medium residential and small business consumers that have interval meters installed. Small business consumers should also have the option to opt-out of the efficient tariff
- Existing flat tariffs will be the default option for small consumers. These consumers should also have the option to opt into an efficient tariff structures.

Under the proposed reforms, the process for setting, introducing and changing tariffs will include consultation with consumers and retailers. Specific provisions will be made for the needs of disadvantaged and vulnerable consumers.

6.3 Other Power of choice issues

We are also developing a Regulatory Investment Test for Distribution (RIT-D) to be published by August 2013. Network businesses will be required to complete a RIT-D before selecting major projects to meet the needs of their network. The RIT-D requires DNSPs to assess the costs and benefits associated with potential projects in order to identify the most economical option available. This will ensure that network businesses meet the needs of the electricity distribution network in the most economical way.

When applying the RIT-D to identify how to meet the needs of the distribution network, network businesses must consider alternatives to building infrastructure (network augmentation). This may include increasing the capacity for load to be transferred to less constrained areas of the network or to off-peak times. It may also include initiatives to manage growth in overall or peak demand for energy services so that network augmentation is no longer required.

6.4 Timing of issues and deliverables

The timing of most demand management issues is uncertain, given that many of the Power of Choice recommendations require amendments to the NER. However, we must develop a RIT-D by August 2013. An initial issues paper is currently out for consultation.

7 Confidentiality

The NER requires us to publish the Confidentiality Guidelines.[9] The Confidentiality Guidelines will set out how we will consider confidential information for regulatory determinations. The Confidentiality Guidelines will cover the types of information that is considered confidential and the process for disclosure to ensure more information is available for stakeholders to engage in the regulatory determination process.

The Confidentiality Guidelines are binding on DNSPs, TNSPs and the AER.[10] The CRG will be kept informed on the progress of this Confidentiality Guidelines throughout the process. We are of the view that only a very small amount of information should be classified as confidential. Further, businesses should demonstrate what detriments will be caused to it if we consider that the piece of information should be made public.

Issues Box 5

- The types of information that should be classified as commercial in confidence

- Claims over entire documents or entire submissions

- Logistics of making confidentiality claims

- Scope and coverage of the guideline.

7.1 Timing of issues and deliverables

- Release of the Confidentiality Guidelines issues paper—2 April 2013
- Working group/roundtable meeting(s)—commencing from 8 April 2013
- Submissions on the issues paper close—29 May
- Release of the draft Confidentiality Guidelines—5 August
- Submissions on the draft Confidentiality Guidelines close—20 September
- Release of final Confidentiality Guidelines—11 November.

9 NER, clauses 6.14A(a), 6A.16A(a).
10 NER, clauses 6.14A(d) and 6A.16A(d).

8 Service provider consumer engagement

This guideline will set out how we expect NSPs to engage with consumers and respond to issues raised in preparing regulatory proposals.

Staff have not identified key issues at this time for referral to the CRG. However, staff are cognisant that the guideline should:

- be principles based on best practice suggestions
- suggest forms of engagement
- suggest content of engagement
- aim to improve the accountability of businesses
- provide practical advice on how to find consumer representative groups
- provide some measurables for us to assess the 'overview paper' which much accompany regulatory proposals. This should include use of plain language and how relevant concerns of electricity consumers have been identified and addressed as a result of engagement.

Information staff gather during the consultative process will feed into the ongoing support and education to improve consumers' understanding of the electricity and gas markets and the regulatory process.

8.1 Timing of issues and deliverables

We expect to provide a copy of a discussion paper to the CRG and obtain their views. The draft guideline, due for release in May 2013 may also be presented to the CRG for feedback. The final guideline is expected to be published by 1 August 2013.

Glossary

Shortened form	Extended form
ACCC	Australian Competition & Consumer Commission
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
Capex	capital expenditure
CRG	consumer reference group
DNSP	Distribution Network Service Provider
NEO	National Electricity Objective
NGR	National Gas Rules
RPP	revenue and pricing principles
RoR	rate of return
NSP	Network service provider
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
NSP	Network Service Provider
Opex	operating expenditure
PTRM	post-tax revenue model
RAB	regulatory asset base
TNSP	Transmission Network Service Provider
WACC	weighted average cost of capital