Submission to the AER on its Preliminary Determination

Demand Management

Summary

This document sets out Ergon Energy's response to the Australian Energy Regulator (AER) on Demand Management.

Ergon Energy notes the AER's Preliminary Determination in relation to:

- **The demand management step change expenditure and efficiency of this expenditure.**
- **Additional explicit capex reductions in relation to the use of demand management initiatives**

However, Ergon Energy would like to highlight that:

- **With new information that has become available since the original submission we have revised our demand management program**
- **The EMCa review of augmentation expenditure indicated our application of demand management contributed to significant reductions in our orginal augmentation forecast**
- **The demand management program is based on supporting the risk created from projects that have been removed from the original capital forecast.**

Outcomes

In light of the additional information that has become available, Ergon Energy have revised the demand management program forecast expenditure to $48.2M supplying 91MVA of demand reductions and supporting the deferral of $603M of capital expenditure.

Contents

1. Introduction 3
2. AER's Preliminary Determination 4
   2.1. AER Preliminary Decision 4
3. Our Response to the EMCa technical review 5
4. Our Response to the AER's preliminary determination 5
List of Changes 12
Definitions, acronyms, and abbreviations 14

1. Introduction

On 30 April 2015, the Australian Energy Regulator (AER) released its Preliminary Determination on Ergon Energy's Regulatory Proposal for the regulatory control period commencing on 1 July 2015 and ending on 30 June 2020.

This document details our response to the AER's Preliminary Determination and stakeholder comments on Demand Management.

2. AER's Preliminary Determination

Attachment 7 of the AER's Preliminary Determination details its position on Operating Expenditure which includes Demand Management. The following sections summarise these positions and the AER's rationale.

2.1. AER Preliminary Decision

For total opex the AER stated the following

> We are not satisfied that Ergon Energy's forecast opex reasonably reflects the opex criteria.1 We therefore do not accept the forecast opex Ergon Energy included in its building block proposal.2[1]
>
> We have not included any step changes in our forecast opex for Ergon Energy. We are not satisfied that adding step changes for the cost drivers identified by Ergon Energy would lead to a forecast of opex that reasonably reflects the opex criteria.[2]

However with specific regard to Non-network alternatives (demand management) the AER stated the following

> Ergon Energy has not satisfied us that the incremental costs of these initiatives are efficient.

Ergon Energy's response to the AERs comments are discussed in Section 3.

[1] AER Preliminary Decision Attachment 7, page 9
[2] AER Preliminary Decision Attachment 7, page 23

3. Our Response to the EMCa technical review

In its Preliminary Determination, the AER has advised that it employed EMCa as a consultant to advise about specific elements of Ergon Energy's proposal.[3]

In its report to the AER[4], EMCa were asked to consider a number of specific matters as part of their assessment. Ergon Energy would like to highlight some of the findings from the EMCa technical review and in relationship between demand management and augmentation:

- The extent to which Ergon Energy develop and apply demand management,
  - EMCa found significant evidence to support Ergon's claims that augmentation is a last resort option
- The impacts of a low growth environment
  - The EMCa indicated that in a low growth demand forecast the application of demand management is particulary important as the application of demand management may enable avoidance of augmentation indefinitely, and; [5]
- Evidence that the original augmentation expenditure was reduced in part due to demand management.
  - EMCa found evidence to indicate that demand management has contributed to significant reductions in our orginal augmentation forecast. [6]

All which support Ergon Energy's efforts in utilising demand management and alternative options for avoiding investment in network infrastructure.

4. Our Response to the AER's preliminary determination

The following sections detail our response to the AER's preliminary Determination.

The AER stated

> We have not included a step change in our alternative opex forecast for Ergon Energy's demand management step change. We are not satisfied that this step change results in an efficient opex/capex trade-off.
>
> Ergon Energy proposed a 'non-network alternatives' step change of $17.5 million ($2012–13) to avoid augex through demand management.

As part of the original submission Ergon Energy has reduced the augmentation expenditure forecasts on the basis of implementing non-network alternatives in order to manage our network risks. Since

[3] AER Preliminary Decision Attachment 6, page 23

[4] EMCa report to AER: Review of Proposed Network Augmentation and Replacement Expenditure in Ergon's Regulatory Proposal 2015-2020 Final version 8.3, 20/04/2015, page i

[5] EMCa report to AER: Review of Proposed Network Augmentation and Replacement Expenditure in Ergon's Regulatory Proposal 2015-2020 Final version 8.3, 20/04/2015, page 32

[6] EMCa report to AER: Review of Proposed Network Augmentation and Replacement Expenditure in Ergon's Regulatory Proposal 2015-2020 Final version 8.3, 20/04/2015, page 62

the original proposal, Ergon Energy has continued to review the network risks, capital and non-network forecast program and revised the non-network forecast expenditure from $60.5M to $48.2M for the regulatory control period 2015-20.

It is important to note that this revised non-network (demand management) forecast expenditure increases the network risks in several key areas, including:

- The number of network elements that must operate at higher risk levels and without further risk mitigation from non-network alternatives the overall network risk will increase putting pressure on network performance metrics
- Ergon Energy's forecast expenditure for safety net will be event triggered operational expenditure and while the risk exposure has been further quantified since our original submission, asset renewal expenditure reductions will potentially expose Ergon Energy to a high number of safety net driven events
- The reduction limits our ability to innovate utilising non-network alternatives including integration into BAU as well as the magnitutude of non-network alternative demand reductions
- Our forecast is based on low growth scenario and there is no protection in our CAPEX or OPEX allowing for an upswing in demand growth which would increase our network risks

We note the AER's commentary on the demand management step change stating that *We consider Demand Management opex can be a valid alternative to capex. However, in the absence of evidence to show that it is an efficient opex/capex trade-off we cannot include an increase in opex for demand management in our alternative opex forecast*[7]. As described in our response to the AER information request AER Ergon 015 on the 20th January all operational expenditure was built using a top down model. In the development of the demand management allocation Ergon Energy did perform a draft bottom up program build to validate the magnitude of the expenditure and to consider key changes between regulatory periods. These changes included the amount of available external contribution to the program and the additional carryover expenditure associated with existing demand management contracts. These factors were described in the response to the information request mentioned above.

Ergon Energy has revised its forecast demand management expenditure. The revised program has been built on the basis of funding existing committed projects as well as augmentation projects previously removed and hence not included elsewhere in our capital program forecast. Our standard operating practice is to examine all opportunties for deferral of capital expenditure,which we will continue over the 2015-2020 regualtory control period to optimise our capital expenditure. EMCa recongised this process in note 141 of their review. Any additional demand management expenditure required during the 2015-2020 period, above our current forecast, to further optimise investment will be funded via efficient capex opex trade-offs at the project level, rather than attempting a program level estimation at this point in time. We feel that this approach will deliver the most prudent overall investment outcome.

We have reviewed the Demand Management program based on the AERs comments and new information that has become available. As a result we are submitting a revised demand management program which will support 91MVA of demand reductions for a forecast expenditure of $48.2M. The following details Ergon Energy's response to the AER Preliminary decision regarding demand management forecast expenditure and MVA targets and is represented in 2013 dollars with no escalations.

[7] AER Preliminary Decision Attachment 7, page 305

Our response includes:

- further information as requested in the AER's Preliminary decision
- additional information that was unavailable or has been further quantified since our original submission, and;
- clarifications on items contained in the preliminary decision

Our revised program includes some reductions and increases in forecast operational expenditure, including:

- a reduction in the forecasted safety net expenditure of $11M to $3M based on changes to our original submission assumptions from the development of detailed safety net reviews
- a reduction in the forecasted Smart Network Program – EMR of $5M to $0 based on a transfer of funding source
- a reduction in the program management costs and a reallocation of appropriate costs to the planned programs to reflect a reduced program size, and;
- an increase of $9.2M from an accounting reallocation of costs from the existing network support contracts.

Ergon Energy's demand management forecast expenditure for planned programs of total $24.1M will target 50.2MVA of new demand reductions providing support for an estimated[8] $220M of capital deferral, which has already been removed from our 2015-20 augmentation capital expenditure forecast. Our carry-over of committed contracts from the 2010-2015 regulatory control period has a forecast expenditure of $18.5M enabling us to access 41MVA[9] of contracted demand, that supports an existing capital deferral of $360M. The carry-over of existing demand management contractual arrangements are based on the lowest NPV evaluation of network and market based opportunities developed at the time. Details of our forecast demand management expenditure can be seen in Table 1 with the associated forecast of additional demand reductions detailed inTable 2.

Table 1- Revised demand management forecast expenditure

DM Portfolio	2015/16 ($'000)	2016/17 ($'000)	2017/18 ($'000)	2018/19 ($'000)	2019/20 ($'000)	Total ($'000)
Committed works	**5,132**	**4,295**	**3,270**	**3,029**	**2,848**	**18,574**
Contracting demand phase	1,892	1,055	330	300	200	3,777
Maintenance/operational phase	3,240	3,240	2,940	2,729	2,648	14,797
Planned programs	**2,946**	**3,800**	**4,595**	**5,285**	**5,680**	**22,306**
Network Constraint targeted programs	2,246	2,950	3,545	4,035	4,280	17,056
Safety net risk mitigation	350	400	600	750	900	3,000
Broad-based and mass market	350	450	450	500	500	2,250
Smart Network Program - EMR	**0**	**0**	**0**	**0**	**0**	**0**
Demand Management Innovation Allowance	**1,000**	**1,000**	**1,000**	**1,000**	**1,000**	**5,000**
Program Management	**475**	**475**	**475**	**475**	**475**	**2,375**
Total	**9,553**	**9,570**	**9,340**	**9,789**	**10,003**	**48,255**

[8] Some capital deferrals will include a range of interventions of which demand management is one component, refer section 2.7.1

Table 2 - Forecast additional demand reductions

Additional Demand Targets	2015/16	2016/17	2017/18	2018/19	2019/20	Total
Targeted Broad-based Programs	0.5	0.8	0.8	1.1	1.2	4.4
Safety net risk mitigation	1	1	1.5	1.5	1.5	6.5
Network Constraint targeted programs	7.1	7.2	7.4	8.4	9.2	39.3
Total Additional Demand	8.6	9	9.7	11	11.9	50.2

Ergon Energy remains committed to demand management and will continue to explore options for additional efficient capex/opex trade-off during the 2015-20 regulatory control periodin line with our standard operational practice.

Additional information on changes to our forecast demand management operational expenditure includes:

Quantification of forecast safety net expenditure

Due to the timing of our original submission we made a series of assumptions on the demand management costs associated with applying safety-net. Since our original submission the safety-net program has been further quantified with the development of over 200 detailed safety net response action plans. These plans include a range of operational practice changes, risk assessments, risk coverage requirements and event likelihood that has enabled use to reduce our forecasted safety-net demand management expenditure.

Safety net was developed for low probability high impact events and we are forecasting that in any one year, on average, we would only expect one significant safety net event which would require the deployment of safety-net generation support. While our forecast safety net risk exposure supported by demand management remains at 16.6MVA, one safety net event per year would result in a forecasted deployment of 6.5MVA of demand management over the 5 years. This forecast reduction in the deployed generation enables a corresponding reduction in the forecast expenditure from $14.6 to $3M. Given that this program will be driven by equipment failures it is a forecast only and could require more or less funding and MVA over the 5 years.

This expenditure will be utilised to support the operational run costs of generation and has no allowance for capital costs associated with the installation of generation injection points. Any capex required for installation of the generation connection points will be funded through capex programs.

Reductions in targeted demand program

In the development of the demand management allocation Ergon Energy performed a top down model based on 2013 growth project forward then validated the program against a draft bottom up program build to verify the magnitude of the expenditure and to consider key changes between regulatory periods. Since the original build growth rates have continued to ease enabling a reduction in the forecast expenditure and demand targets for the coming 2015-2020 control period see Figure 1. The initial program forecast was based on a growth rate that would have led to a system maximum demand of approximately 2530MVA (2013 low growth forecast) by 2020. The most recent growth forecast indicates a maximum demand by 2020 may be closer to 2310MVA (2014 low growth forecast). Care must be exercised when using system level growth forecasts in this way as it can be heavily impacted by large customers leaving and joining the network over the forecast period. Also a system level demand forecast does not necessarily reflect the localised network constraints nor is the relationship between local growth and system growth linear; however it does indicate the magnitude of the softening in demand growth. This softening indicates that a forecast reduction of our demand management targeted program to $17.1M targeting demand reductions of 39MVA is appropriate.

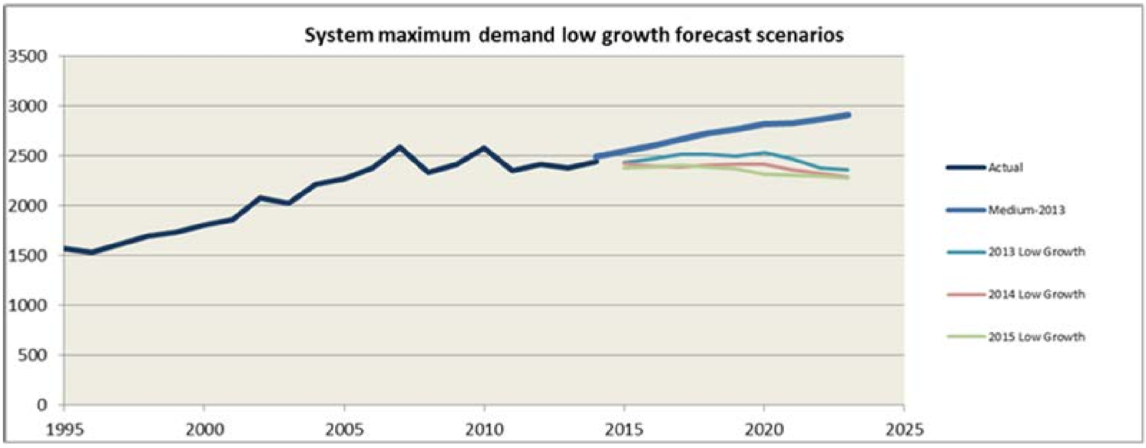

Figure 1 - system maximum demand growth forecast scenarios

An increase due to reallocation of network generation support costs to demand management

An internal reallocation of network support contracts of $9.2M for the 2015-2020 period has resulted in an increase in opex for the demand management program. Due to the allocation process, these costs were not previously included in our opex submission nor the demand management forecast. The generators provide 20MVA of on call network support and are under contract until 2018 with a 5 year option to extend. Details of the contracts contain market sensitive information and are available on on request.

Removal of forecasted programs

The forecasted $5M Smart Network - Effective Market Reform programs of work will be self-funded and therefore have been removed from the forecasted demand managed expenditure. Any associated demand savings that may have been attributable to these programs have also been removed from the forecast demand targets.

Our revised demand management expenditure is in alignment with our historical total program cost glide path targeting a delivery cost for demand management below $500 per kVA see Figure 2 (average cost to deliver demand management, DM outcomes 2013-14.pdf page 6).

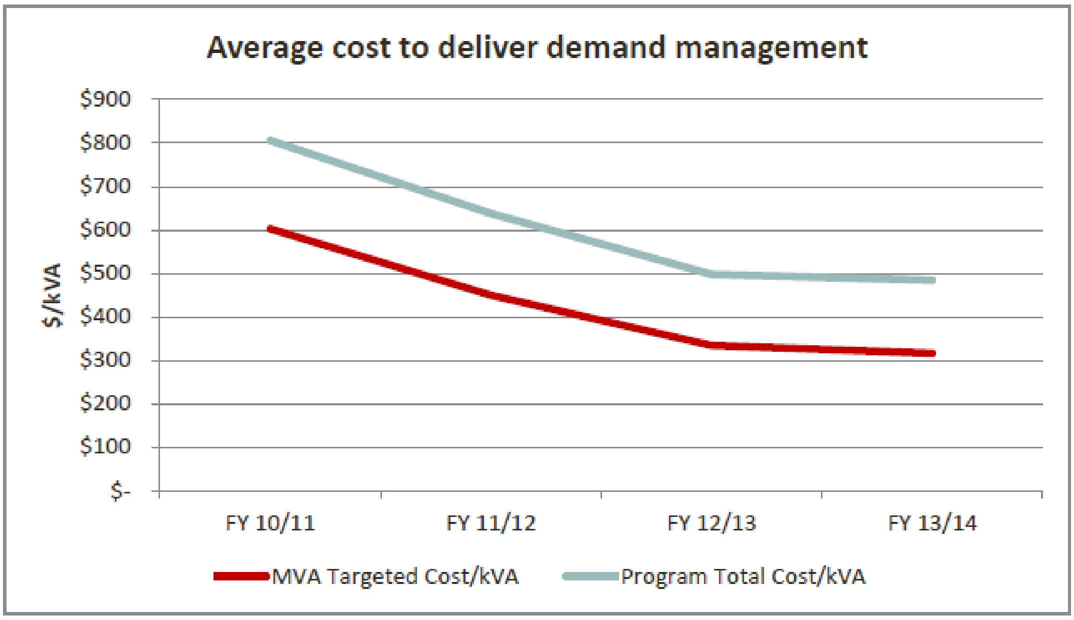

Figure 2 - Demand management delivery costs

4.1.1. Ergon Energy's cost benefit analysis

The AER stated that

> *We would expect Ergon Energy as part of its revised proposal to provide the costs of the benefits of its demand management step change*[10]

And

> *The overall benefit of Ergon Energy's demand management program, in terms of capex reductions, was not clear*[11]

As described above Ergon Energy has reviewed its demand management submission, considering changes since the initial submission and developed a revised proposal. Our revised proposal has a reduced allowance for any increased need for demand management throughout the regulatory control period. Ergon Energy will instead investigate efficient Capex/Opex trade-offs during the Regulatory control period as part of our normal planning process. This Capex/Opex trade-off will be performed at a project level, as more detailed information and conditions are known, rather than attempting a program level estimation at this point in time. This approach will ensure the most prudent final investment outcome.

We note the AER's comments with respect to augmentation expenditure that *We are therefore considering whether it is appropriate to estimate the amount of capex that may be efficiently deferred through the use of demand management initiatives and explicitly reduce the capex forecast by this amount.*[12]

Ergon Energy notes that this would not be appropriate.

We highlight that Ergon Energy's revised Demand Management proposal does not have any funding allocated for projects contained within the forecasted augmenatation capital expenditure under Ergon Energy's regulator proposal, but is focused on the risk of constraints/projects that have already been removed as well as the continuation of existing demand management activities.

Additionally the augex submission compilation, including the implementation of the new security criteria including Safety Net, a range of Sub transmission and Distribution projects were removed. The revised demand management program will target reduction of risk of non compliance at the appropriate locations that have had capital projects removed owing to Safety Net or where Demand Management was deemed to be a more efficient investment.

The total removed expenditure that is being supported by demand management is:

- $187M of sub transmission augmentation projects deferral from the 2015-2020 period which would have added an additional 329MVA of capacity, see Question 037 – Augex supporting information, and;
- A program level removal of $56M of distribution forecast investment over approximately projects at some 34 asset locations which would have added an additional estimated capacity of 17MVA.

Our demand management targeted program is forecast to deliver 39MVA of demand reductions or 11% of the deferred capacity at a cost of $17M or 7% of the deferred investment.

[10] AER Preliminary Decision Attachment 7, page 306
[11] AER Preliminary Decision Attachment 7, page 304
[12] AER Preliminary Decision Attachment 6, page 112

In addition to the augmentation deferral, safety net forms a key part of the transition to probabilistic planning and it increases operational response and expenditure to balance reductions in capital expenditure. The operational cost associated with this change was included under our demand management program due to the opex/capex tradeoff. We have also looked for efficient opportunities to provide some of this response coverage by customer demand management to ensure we comply with our safety net requirements. The application of probabilistic planning has enabled an estimated $550M in augmentation expenditure to be removed or deferred from our forward program of capital work, provided we are able to meet the restoration times specified in the safety net.

In summary Ergon Energy's revised 2015-2020 demand management forecast expenditure of $48.2M is fully or partially supporting:

- $187M of sub transmission augmentation deferrals,
- $56M of distribution deferrals,
- $550M of asset deferrals or removals, due to safety net, and;
- $360M of asset deferral carry over from 2010-2015.

4.1.2. Broad based demand management and indirect benefits

Ergon Energy notes the following comments made by the AER regarding Ergon Energy's broad based demand management (BBDM) program.

We also note that Ergon Energy has included broad based demand management (BBDM) programs in its demand management program.[13]

And

The benefits of BBDM on deferred capex is not clear and we consider only opex that directly translates to a quantified decrease in capex should result in an efficient opex/capex trade-off[14]

Ergon Energy's BBDM program is a targeted program that utilises mass market delivery techniques, it is not a program that is used broadly without consideration of capital trade-off cost benefits. The program targets network risk areas in order to provide near to mid term capex deferral utilising mass market program methodologies to enable economies of scale for efficient delivery. Certain demand management market segments, such as residential, have high contract numbers with low demand and in order to be delivered economically, must be delivered via mass market BBDM program techniques, but do not necessarily have to be delivered across all of Ergon's coverage area.

BBDM products are carefully chosen to provide customer benefit at an efficient cost and aim to support, engage and encourage demand management participation from all our customers. The program provides a range of customer benefits such as education, tariffs and direct incentives as well as other non-tangiable benefits like, reducing barriers for future programs, improving consumer awareness and enabling participation, overall ensuring a sustainable dynamic engaged demand side market.

[13] AER Preliminary Decision Attachment 7, page 304
[14] AER Preliminary Decision Attachment 7, page 306

List of Changes

Table 3 sets out the changes we have made to regulatory proposal documentation in response to the AER's Preliminary Determination.

Table 3: Revisions to our regulatory proposal documentation in relation to demand management

Document	Section/Table	Revision
06.01.02 Forecast Expenditure Summary System Operational Expenditure 2015 to 2020	Table 1	• Updated to reflect revised operating forecast expenditure (direct costs) for 14-15 year
	Table 2	• Updated to reflect revised operating forecast expenditure (total costs) for 14-15 year
	Section 2	• Removed reference to forecasts for next regulatory period as detailed in the 06.01.01 – (Revised) Forecast Expenditure Summary – Operating Costs
	Section 4	• Updated tables to reflect the 2014-15 forecasts
	Section 5.2	• Removed BST methodology diagram as detailed in 06.01.01 – (Revised) Forecast Expenditure Summary – Operating Costs
	Section 5.3	• Removal of references to the 2012-13 base year as detailed in 06.01.01 – (Revised) Forecast Expenditure Summary – Operating Costs • Removal of expenditure forecasts for next regulatory control period as detailed in 06.01.01 – (Revised) Forecast Expenditure Summary – Operating Costs
	Section 6	• Removal of expenditure forecasts for next regulatory control period as detailed in 06.01.01 – (Revised) Forecast Expenditure Summary – Operating Costs
07.02.11 Demand Management Overview	Section 1 Executive Summary	• Updated to reflect revised demand management forecast expenditure
	Table 1	• Updated to refelect revised forecast expenditure
	Table 2	• Updated to refelect revised forecasted demand targets
	Section 6.4	• Updated total deferral value of program
	Section 7	• Updated demand management operational progams to reflect forecast program of works
	Section 7.3	• Broad based and regional – updated to clarify targeted application of program
	Section 7.3.1	• Updated to refelect the clarifications to the impact on forecast augmentation expenditure.
	Section 7.3.1	• Safety net benefits – included and update to clarify the application and benefits of safety net.
	Section 9	• Updated to refelect the revised program of works
	Section 9.2	• Updated to highlight and clarify the allowance for an upswing in demand growth

Document	Section/Table	Revision
	Section 9.8	• Updated to include revised demand management targets in alignment with revised demand management submission.
	Table 8	• Updated to include revised demand management targets
	Table 9	• Updated details
	Section 9.10	• Demand management forecast expenditure updated
	Table 10	• Updated forecast demand management expenditure
	Section 9.10	• Clarified the risks remaining in the demand management program.
	Table 11 and Table 12	• Merged Table 11 and 12 into one table for clarity.

Definitions, acronyms, and abbreviations

AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
ARR	Annual Revenue Requirement
CAC	Connection Asset Customers
CAM	Cost Allocation Method
Capex	Capital expenditure
CESS	Capital Expenditure Sharing Scheme
CPI	Consumer Price Index
DMIS	Demand Management Incentive Scheme
DMEGCIS	Demand Management and Embedded Generation Connection Incentive Scheme
DNSP	Distribution Network Service Provider
DUOS	Distribution Use of System
EBSS	Efficiency Benefit Sharing Scheme
EDSD	Electricity Distribution Service Delivery
EG	Embedded Generation
ENA	Energy Networks Association
ENCAP	Electricity Network Capital Program
Ergon Energy	Ergon Energy Corporation Limited
GSL	Guaranteed Service Level
ICC	Individually Calculated Customer
ICT	Information and Communication Technologies
IDC	Interdepartmental Committee on Electricity Sector Reform
IDS	Investment Decision Support
IRP	Independent Review Panel on Network Costs
MRP	Market Risk Premium
MSS	Minimum Service Standards
NECF	National Energy Customer Framework
NSP	Network Service Provider
NER	National Electricity Rules
Opex	Operating expenditure
PTRM	Post Tax Revenue Model
QCA	Queensland Competition Authority
RAB	Regulatory Asset Base
RBA	Reserve Bank of Australia

RFM	Roll Forward Model
RIN	Regulatory Information Notice
SAC	Standard Asset Customers
SPARQ	SPARQ Solutions Pty Ltd
SSIS	Small-Scale Incentive Scheme
STPIS	Service Target Performance Inventive Scheme
SWER	Single Wire Earth Return
TUOS	Transmission Use of System