ENERGEX Response to AER Issues Papers on Guidelines, Models and Schemes

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THE SERVICE TARGET PERFORMANCE INCENTIVE SCHEME ISSUES PAPER (STPIS)

Overview

ENERGEX is committed to delivering service performance that meets customer requirements in relation to quality of service and cost. ENERGEX is adopting a customer-centric approach to network management. This change underpins our current planning around understanding and delivering on existing and emerging customer needs and expectations. The establishment of a national regulatory framework is seen to contribute to achieving this objective.

ENERGEX's view of any service performance scheme is that it should:

- Focus on community imperatives as well as individual customer issues;
- Recognise broad performance (averages) as well as outlier performance;
- Recognise jurisdictional differences;
- Identify key priority areas and link these to performance measures;
- Acknowledge network and non-network solutions to service improvements; and
- Recognise existing excellence in performance as well as identified improvements.

In Queensland, these objectives are addressed through codified Minimum Service Standards (MSS) and a separate Guaranteed Service Level (GSL) scheme. The MSS supports incremental reliability performance improvements and the GSL scheme addresses customer service and reliability issues. The separate GSL scheme promotes a focus on performance and service for individual customers while the MSS provides for the more global community view of overall performance. Separation of these schemes is endorsed as it provides the opportunity to appropriately focus on performance at the global community level as well as at the individual customer level. Coordination of these schemes at state and national levels must be a key component of any STPIS to avoid inefficiency.

It is noted that various STPIS schemes (current and redundant) across three States have addressed service performance with varying levels of success. The existence of these multiple STPIS schemes indicates that:

- there are various ways of addressing service performance;
- some of the schemes have been more successful in delivering target objectives;
- these schemes have historically operated separately to GSL schemes;
- there will be complexities associated with transitioning to a single national scheme; and
- Transitional issues will need to account for jurisdictional differences, system changes, administrative differences, measurement and definition variations and impacts of State legislation.

The introduction of a STPIS would need to demonstrate additional benefit to customers beyond those achieved through the existing arrangements. This would require a detailed comparative analysis of the issues such as impacts on systems, administrative and management processes, reporting arrangements and resorting matters.

Consideration must be given to the impact of any proposed STPIS on customers, specifically in terms of the performance improvement on associated costs. To this end, consistent with the commencement of similar schemes in jurisdictions previously, a paper trial would be appropriate for those States where there is a significant change to the scheme or where there has been no previous scheme in place.

Detailed Response

ENERGEX's more detailed response to the Service Target Performance Incentive Issues Paper is outlined in the table below.

2.3 National Framework	
The AER would like views on whether it is feasible and appropriate to establish a common approach within a national framework	ENERGEX is committed to delivering service performance that meets customer requirements in relation to quality of service and cost. Queensland has existing compliance obligations around service standards. The current codified MSS includes targets that are reviewed periodically. The codified GSL scheme addresses individual customer issues that deal with outlier performance. In addition, there is a comprehensive reporting regime on these measures. Considerable effort has been directed towards developing and implementing these schemes in the current regulatory period. ENERGEX's consumer research indicates that its customers seek to maintain or improve current service levels without additional expense. Given the current MSS arrangements focus on continuing improved service performance the introduction of a STPIS would need to demonstrate additional benefit to the customer. Cost effective integration for the DNSP's range of different systems and characteristics is a feasibility issue. Depending on the amount of change to existing management and systems, implementations cost and lead time are significant factors that should be considered when assessing feasibility. Prior to endorsing an additional scheme (national or otherwise), ENERGEX would seek to better understand the benefits to our customers.
The AER would also like views on the issues it may need to consider in establishing this framework. In particular: • ***What should be the key elements?*** • ***How might a national scheme deal with differences between regions/jurisdictions?*** • ***What are the possible obstacles to achieving an effective national framework?***	The scheme would need to provide additional benefits to the customer beyond those currently being received. <u>Some key elements:</u> • simple to administer; • small number of reliable and verifiable performance measures in priority areas; • appropriate recognition of DNSP for performance changes; • interaction with other incentive schemes does not result in conflicting messages; • reasonable transition arrangements and lead times; • recognition of the benefits of non-network alternatives; and • early identification of financial implications to allow capital program planning. <u>Jurisdictional/Regional differences</u> Consideration of jurisdictional/regional imperatives would need to be stipulated. Recognition of impacts on network performance including: • topography (length of overhead and underground; asset age; number of thunder days, rainfall, bushfire; etc) • "saturation point" where cost of improvement in performance outweighs the benefits to customers; • customer preferences and profiles drive different DNSP targets; • historical performance and capital spend; • network descriptors and associated measures; and

	• jurisdictional performance measures and codes. Obstacles to consider in developing an effective national scheme include: • articulating additional customer benefits; • existing legislative differences and local imperatives; • accounting for impacts on the price review process; • cost effective amalgamation of schemes for various DNSPs; • achieving consistency in performance definitions and measures; • conflicting and/or duplicate State and national requirements; and • establishment and administration costs to support the scheme.

3.1 Public Reporting Schemes	
The AER would like views on whether it should require DNSPs to report on key aspects of their service performance for public reporting purposes.	Reporting should be simple, relevant and at either State or national level. Duplicate reporting at both levels would be administratively inefficient. ENERGEX supports public reporting of service performance and presently reports on financial and service quality to the QCA on both a quarterly and annual basis.
If so, should DNSPs be required to report just on those aspects of service performance measured for an incentive scheme (e.g. GSL scheme or s-factor scheme) or on a common set of agreed measures?	Only performance measures associated with the incentive scheme should be reported. These should be a small number of meaningful and easily reportable measures. DNSP comparisons should not create unrealistic expectations for the community and divert the focus from broader planning requirements. Measures should be consistent at State and national level. Costs associated with any changes to reporting would need to be justified.
The AER would also like views on how future reporting arrangements which may be multi-faceted (i.e. reporting to the AER in relation to an incentive scheme and potentially for public reporting purposes) could be simplified or rationalised to reduce compliance costs.	Reporting on a single scheme without duplication is essential. Other elements include: • small number of relevant and meaningful measures; • standardised definitions and measures; • simple calculation and reporting parameters; • complementary reporting timeframes; • reporting that is relevant and meaningful to the DNSP and customers; and • consistent formats and templates.

3.2 GSL type schemes	
The AER would like views on whether it should develop a national GSL scheme.	Aspects of Service Standards related to GSLs are addressed in the National Framework for Non-Economic Distribution and Retail Regulation. ENERGEX would seek clarification on the outcome of that consultation prior to committing to any actions. ENERGEX supports the principles underpinning a GSL scheme and currently operates under a Queensland scheme. It would support a single scheme, either at a State or national level, but not two concurrent schemes as they would have potential for conflict and ambiguity.
The AER would also like views on issues associated with the implementation and operation of a national GSL scheme.	ENERGEX presently reports and remunerates customers under a Queensland GSL scheme as set out in the Queensland Electricity Industry Code (EIC). Customer remuneration under the current GSL scheme is both reactive and proactive depending on the nature of the issue. In instances of Retailer fault, the process requires ENERGEX to make initial payment to customers and then seek reimbursement from the Retailer. A truly national scheme would require dismantling of State arrangements – some considerations would be: • definition changes; • compliance and administrative costs; • State legislation; • jurisdictional variations (e.g. exclusions for some locations, GSL triggers); • staffing impacts; • data and system impacts; • impacts on customer satisfaction; and • factors outside the control of the DNSP (e.g. Retail, generation related).

3.3 Financial incentive (s-factor) schemes	
The AER would like views on the overall design of a national s-factor scheme. In particular: • ***the form that a national s-factor scheme might take*** • ***whether the scheme should be symmetrical*** • ***the number of measures that should be included, and*** • ***any other relevant threshold matters not dealt with elsewhere in this paper.***	Any national scheme would need to provide additional benefit to the customer beyond the level received under current arrangements. The form of any scheme should: • allow sufficient flexibility to reflect jurisdictional priorities; • allow for certainty for the jurisdiction regarding impacts on revenue; • recognise fluctuations in performance associated with measurement or special events; • recognise current excellence in performance as well as opportunity for performance improvement. Measures should be: • a small number relevant to the DNSP; • meaningful to customers; • simple to extract and report; and • send the appropriate signals in relation to reliability and service improvements. Weightings for measures: • variable on target parameters and categories (such as CBD, Rural and Urban); and • allow flexibility to recognise priority areas for specific improvements. Incentive: The incentive would need to be assessed to gauge the potential impact on CAPEX and OPEX and the benefit it would render. A paper trial of the scheme would provide opportunity to do this. In addition, it should: • be sufficient to drive appropriate behaviours; and • provide certainty around the impact on revenue and capital and operating programs. Targets: • should reflect jurisdictional priorities and recognise imperatives from earlier years; • should recognise existing strong performance (e.g. where network performance is very good there is less scope for service improvement); and • should be based on historical performance. An asymmetrical scheme is preferred because: • symmetry is a reasonable arrangement where there is a strong linear relationship between cost and performance. However, the relationship here is better reflected by a “curve of diminishing returns” – as performance improves and approaches the upper limits, the relationship “flattens out” and there is significant

	financial investment associated with a small unit change; • in cases of strong performance, there is a material risk of penalty because of the greater potential for service performance to decrease, but may be limited opportunity for improvement; and • where STPIS and GSL schemes co-exist, overlap between them could incur double penalties for the same events. Other considerations: • consistency in the STPIS parameters during a regulatory period would be necessary to ensure stable and prioritised investment plans; • early advice and involvement prior to scheme changes would be critical; • at some point, the cost of improvements would exceed the benefit to customers. The scheme would need to account for this.
To what extent should existing s-factor schemes form the basis of a national scheme?	ENERGEX has concerns about applying existing schemes without a comprehensive analysis of their respective merits. Jurisdictions with existing schemes have had time to assess implications and develop internal capabilities to administer the scheme in their business. Some have refined their schemes over successive periods. Where a DNSP does not have a STPIS, there should be suitable transition arrangements, including lead time and costs and pass through arrangements. A Working Group to formally review current schemes and develop an appropriate national option would be supported.

	3.4 Interaction between GSL schemes and s-factor schemes
The AER invites views on the establishment of both GSL and s-factor schemes in a national framework. In particular: • ***should both types of schemes be implemented*** • ***is the value to customers of having both types of schemes sufficient compared to the additional costs associated with having to implement and administer multiple schemes,*** • ***and how should information requirements be set to minimise compliance and collection costs?***	STPIS and GSL schemes should operate separately either at a State or national level but not both. These schemes reflect different purposes, focussing on broader "average" customer service or individual customer "outlier" performance. Separate schemes would better serve customers and ensure the purpose of either scheme is not lost. Overlap between the schemes needs to be avoided. ENERGEX would seek to understand implications of a national scheme on its operations and how this would differ to its existing arrangements. Compliance costs should be minimised by: • one national or State GSL scheme; • assessment of additional benefit of national STPIS to customers compared to any existing arrangements; • no duplication of or conflict with other reporting requirements; • changes to local systems that are achievable within the DNSP operating constraints; and • reasonable transition arrangements.

4.1 Reliability indicators	
The AER would like views on which measures of reliability to include in a national s-factor scheme.	Measures for STPIS should include SAIDI and SAIFI. These are priorities for ENERGEX with delineation of CBD, Urban and Rural. They are included in the MSS. Inclusion of CAIDI is not recommended. It is a function of SAIDI and SAIFI and hence any disproportionate improvement in one can have a negative impact on the overall measure.
The AER would also like views on the classification of feeders by type and whether the AER should distinguish between planned and unplanned interruptions.	ENERGEX currently categorises and supports the classification of its feeders by CBD, Urban & Short Rural. Distinguishing between planned and unplanned interruptions is supported: • planned outages are associated with network maintenance to minimise unplanned events; • an incentive to prevent/minimise planned outages could promote practices that are counter to network security and safety; and • the STPIS incentive should be associated with reducing unplanned interruptions hence reporting on this parameter only.

4.2 Quality indicators	
The AER would like views on the appropriateness of incorporating quality indicators in a future s-factor scheme, including the likely costs and benefits of incorporating quality indicators, the possible types of measures that could be used, and the availability of historical data.	DNSPs have a regulatory obligation associated with delivery of supply quality. This is a complex issue with complications associated with indicators, measures, customer understanding and impacts outside the control of the DNSP. Quality of supply measures are receiving attention through a number of State and national avenues. The number of working parties currently focused on this issue indicates the measure is not yet at a point where it could confidently be deployed or provide consistent long term signals and incentives.
Should supply quality be addressed in a different way such as through a GSL scheme or some other scheme?	Given the complexities associated with supply quality, it should not be addressed through schemes such as these but rather managed by the DNSP as a part of its normal works program. It would be appropriate to revisit the inclusion of quality in STPIS following the deployment of more advanced metering on a large scale.

4.3 Customer service indicators	
The AER would like views on customer service indicators to be included in an s-factor scheme, including the likely costs and benefits, and feasibility, of incorporating a range of indicators.	Inclusion of any indicators in STPIS would need to assess the relevant costs and benefits of the target parameters as well as customer expectations. The primary focus of STPIS should be reliability indicators, particularly in the initial stages as the scheme is developing. The customer service indicators discussed (e.g. responses to telephone and written enquiries, attendance to connections/reconnections/street light repairs, complaints) can be managed across a range of schemes, including GSLs, internal administrative processes (including complaints systems) and STPIS. Inclusion of customer service indicators in STPIS is understandable if they provide a global community view of overall performance that is simple and measurable (Jurisdictional differences would need to be considered). Customer specific indicators are more appropriate to a GSL or other arrangement as discussed below.
Would customer service indicators be more appropriately addressed in a GSL or other scheme?	Some customer service indicators are more appropriately addressed in a GSL Scheme as they focus on performance and service for individual customers. (e.g. items related to connections/ re-connections/disconnections and appointments). Inclusion of these measures should be based on relevance to customer expectations and costs. They should also have simple, meaningful measures that are not complex or costly to administer. Other indicators such as quality of telephone response, number and types of complaints are less quantifiable and better monitored and addressed in the businesses. External bodies such as the Ombudsman also have a role in these.

5.0 Approaches to setting rewards and penalties in an s-factor scheme	
The AER would like views on the above approaches for setting incentive rates and other possible approaches. (Approaches listed include marginal cost, customers economic loss VoLL, surveys and willingness to pay)	It is important that the incentive recognise: • the true cost of achieving service performance change; • under the law of diminishing returns, costs associated with a unit of performance improvement materially increases as the underlying service performance improves; • the priorities associated with various customer segments; and • the relevance of the type of measure. The use of different incentive approaches across jurisdictions indicates that: • different methods may suit different topographies; and • it is an evolutionary process with the approaches refined over time. Hence, a hybrid approach may best reflect jurisdictional imperatives as well as level of maturity with STPIS. The decision regarding approach should be guided by rigorous analysis and agreed with the Regulator at the time of determining the framework for each DNSP. An outline of the cost/benefits of the various jurisdictional approaches would be a useful tool.
The AER would like views on the feasibility and associated costs and benefits of adopting each approach.	A detailed comparison of the relative merits of each approach and applicability would provide a sound basis to assess feasibility. This information would be required prior to forming a view and ENERGEX would appreciate the opportunity to discuss these issues specifically with the AER.
The AER would also like views on how it should determine relative weightings for measures.	Weightings should account for: • jurisdictional priorities; • customer priorities; • impacts of local factors such as customer growth; • capacity of the DNSP's program of work to deliver improvements; and • scope to improve performance.

6.0 Approaches to setting performance targets under an s-factor scheme	
The AER would like views on the possible approaches outlined above to setting targets in an s-factor scheme. (Approaches listed include most recent year's result, average historical performance, trends extrapolated from past performance, moving average historical performance and external benchmarks)	Targets that reflect trending from the DNSP's past historical performance would provide a sound basis. Consideration should also be given to: • past imperatives to which the DNSP has been subject and their impacts on the speed and quantum of historical performance improvements; • normalisation for seasonal volatility; and • changes in definitions and recording protocols over time. External benchmarks are not considered appropriate because of difficulty comparing network topologies, climatic and other operating conditions as well as customer preferences and profiles.

7.0 Allowing for Risks	
The AER would like views on mechanisms to deal with additional risk introduced by an s-factor type scheme and whether it is appropriate for such risks to be wholly borne by DNSPs and/or customers.	Risks should be balanced between the DNSP and the customers and provide certainty around revenue management and price impact. The mechanism should include: • deadbands to account for seasonal volatility and data fluctuations; • an overall limit on reward or penalty; • collars; and • capping.

8.2 Quantitative measures	
What approach should the AER take in applying exclusions?	ENERGEX supports the adoption of exclusion events in the STPIS. These are included in the Queensland EIC and relate to events outside the control of the DNSP. Exclusions would therefore need to account for: • transmission system and associated failures; • lack of generation; • directions by authorised parties; • extreme events including storms and cyclones; • events forced by third parties (e.g. damage to property); • retail systems failure impacting on customer service performance; and • Force Majeure. Other considerations include: • recognition of variations in Safety legislation across jurisdictions; and • jurisdictional exclusions for GSL and MSS.
Should exclusions cover reliability indicators and customer service indicators?	Exclusions should apply to both reliability indicators and customer service indicators. This means any exclusions included in legislation should be regarded (e.g. in relation to GSLs the accessibility of any customers property for repairs). The STPIS is intended to improve performance targets and therefore the DNSP should only be accountable for events within its sphere of influence and control.
Should exclusions be determined by reference to qualitative or quantitative measures?	ENERGEX supports the use of exclusions that are specific and measurable. On these grounds quantitative measures would be supported.
How appropriate is a standard such as IEEE 1366-2003?	This standard is considered to be appropriate. It provides a statistical approach to identify major incidents regarded as outliers or abnormal that may otherwise distort underlying performance. ENERGEX has adopted this method in accordance with the requirements of the Electricity Industry Code (EIC) which references IEEE 1366-2003.

8.3 Options to limit the contribution of an excludable event	
Where an exclusion threshold is exceeded what action should the AER take to limit the contribution of events?	ENERGEX supports the approach currently undertaken which is to remove the event to comply with the IEEE 1366-2003 standard.

9.1 Issues for jurisdictions currently without an s-factor scheme	
Are there any other issues that the AER needs to consider?	It is unclear to what extent the introduction of STPIS may require significant review and adjustment to current recording and reporting processes. Other jurisdictions have had the opportunity to implement a scheme and review its business implications. The key will be to achieve alignment with customer expectations and understand the implications for our customers and community. For these reasons, a paper trial would allow the development of a comprehensive practical understanding of how the scheme operates and its benefits.

9.1.1 Issues relating to the availability of data	
The AER invites comments from interested parties on the current and future availability of data on reliability and quality of supply measures for DNSP's currently without an s-factor scheme	• SAIDI, SAIFI: ENERGEX reports on SAIDI and SAIFI as part of MSS and has sound trends based on historical data. This data is externally audited. • Feeders: Feeder categories have been used since the late 1990's. Allocation of feeders to these categories (especially Urban and Short Rural) can change due to factors such as high growth areas, capital and operating work, load transfers and reconfiguration of feeders. • Quality of supply measures: ENERGEX primarily reports on QOS through the capture of customer complaints and time to investigate and restore; MAIFI data is not available for all network switching devices. • Reporting frequency: If STPIS is based on audited 12 month figures (not a progressive review) there is an issue on how to accommodate any accuracy band identified by the auditor (e.g. 200 minutes $\pm$ X%).

9.1.2 Issues relating to the accuracy of data	
The AER invites comments from interested parties on the current and future accuracy of data for reliability and quality of supply measures.	Reliability (SAIDI & SAIFI) – these have a long term reporting history at feeder level, are audited and there is a high degree of confidence in the data. Other measures of reliability and quality are less robust: • Interruption data at individual customer level – accuracy is dependent on customers reporting interruptions which introduce some subjectivity into the data calculation. • MAIFI data – ENERGEX has limited historical data and there is insufficient penetration of detection devices to accurately capture all momentary interruptions. ENERGEX is in the process of further introducing remote telemetry and control on the network. • Worst performing feeders – data is reasonably accurate subject to changing network configurations. • Connectivity - ENERGEX is confident of the quality of the connectivity information between distribution transformers and the higher levels of the network. Connectivity data relating customer premise to the transformer, particularly around low voltage open points is based on spatial rather than electrical connectivity. Therefore, the information is generally adequate for the calculation of feeder performance statistics, although may not be sufficient for proactive claiming of GSLs.
How could the AER take changes in performance data, due to changes in recording systems, into account in setting targets and incentive rates?	Current and proposed data as well as the transition process needs to be documented and verified. This includes: • demonstrating the historical trend for the current method; • determining the changeover point; • calculating in parallel until trends are established; and • adjusting on the new trend line.

9.1.3 Issues relating to the interaction between a national s-factor scheme and mandatory jurisdictional service standards	
The AER invites submissions on issues relating to the interaction between mandatory jurisdictional service standards and a national STPIS for DNSPs currently without an s-factor scheme. For example, what benefits and limitations could the existing mandatory jurisdictional service standards place on the implementation of a national s-factor scheme?	MSS are included in Queensland's EIC and provide certainty around requirements for improvements and hence impacts on revenue and expenditure. Interaction considerations between MSS and a national STPIS include: • STPIS targets would need to be better than the MSS targets and carry sufficient reward to encourage performing above the minimum requirement; • STPIS targets would need to account for the annual incremental improvements embedded in MSS reliability targets; • jurisdictional imperatives should be considered; • community and social considerations need to be balanced with individual customer requirements; and • GSLs are included in legislation and could give rise to definition issues.

9.2 Transitional issues for jurisdictions with an s-factor scheme	
Are there any other issues that the AER needs to consider?	There may be a preference for jurisdictions with existing schemes to promote current STPIS. It is important that the AER assess the status of all jurisdictions and quantify the impact of a new scheme on all affected participants. Different points on the development continuum would require different treatment across the DNSPs.

9.2.1 The availability and accuracy of data	
The AER invites submissions from interested parties on current and future data availability and accuracy in relation to DNSPs currently with an s-factor scheme. In particular, the AER would like views on the availability and accuracy of service reliability and quality data, including the level of the network at which this data is recorded.	Changes to current data definitions, data gathering and reporting to achieve consistency across jurisdictions will have different degrees of financial, administrative and reporting impacts. Experience indicates that changes to definitions and reporting categories may take several months to embed.

9.2.2 Changing the structure of schemes (definitions/exclusions)	
The AER invites comments from interested parties on whether changes in reporting and the incentive mechanisms themselves should be taken into account in developing targets for DNSPs currently with an s-factor scheme	Changes to data definitions or the compilation of data would impact on calculations and forecasts for a DNSP and would therefore have to be taken into consideration in setting targets. Data changes could also impact on reporting to other local legislative entities. Consideration must be given to ensuring that multiple definitions or data items do not make the scheme confusing and difficult to administer. A DNSP's system and modification capability must also be considered when determining data definition and reporting frequency. Customer education may be an issue where revised data definitions result in changes to reported outcomes. Actual physical changes compared to revised reporting changes must be clear. For ease of transition to a national scheme, especially for jurisdictions without history of these schemes, reporting and data requirements need to be kept relatively simple in the first regulatory period.

9.4 Transitional issues in relation to guaranteed service levels	
If the AER were to develop a national GSL scheme, what issues arise regarding existing GSL schemes (that are mandated under jurisdictional electricity legislation) operating concurrently with a national scheme.	In Queensland GSLs are prescribed in the EIC. ENERGEX has developed its systems capability around these requirements which include both proactive and reactive GSLs. DNSPs should not be subject to duplicate schemes as the compliance costs would outweigh any derived public benefit. Changes to the definition or calculation of a GSL would need to be considered with respect to the associated costs and implementation requirements. Consideration must also be given to the different legislative requirements (e.g. de-energising and re-energising). Variations between a national and State scheme would result in non value adding compliance, administration and reporting costs. Transitional issues would include matters such as legislative review, systems and process change, communications and time frames
In relation to existing GSL schemes that are not mandated, what issues arise in relation to transitioning these schemes to a national scheme, should this be considered appropriate?	The GSL scheme in Queensland is mandated with both reactive and proactive GSLs. Any changes required to transition to a national scheme could result in a DNSP having to undertake the following: • system modifications to enable data capture; • resourcing to meet revised standards (i.e. cycle times); • customer and staff education; and • revised processes and procedures.

GUIDELINES, MODELS AND SCHEMES ISSUES PAPER

Overview

In general, ENERGEX supports the proposed guidelines and models but has some reservations regarding the Efficiency Benefits Sharing Scheme (EBSS). In making these responses ENERGEX is mindful that it has transitional arrangements for related matters as follows:

- capital contributions;
- Efficiency Benefits Sharing Scheme (EBSS); and
- treatment of the Regulatory Asset Base (RAB).

Clarification is sought on the term Regulatory Asset Base (RAB) with reference to ‘standard control services’ and ‘direct control services’. In determining the Building Block (Clause 6.4.3(a)) reference is made to Clause 6.5.1(a) of the National Electricity Rules (NER) which states that the RAB for a DNSP is the value of those assets used to provide ‘standard control services’. It is unclear where ‘alternative services’ are considered.

In principle ENERGEX supports the use of the TNSP PTRM as the basis for the DNSP PTRM but has concerns in relation to the following:

- indexation should more accurately reflect the cost components of the RAB (e.g. labour and materials) rather then just a generic indexation rate;
- the return of asset and return on asset calculations are a departure from ENERGEX’s current regulatory arrangements under the QCA and will impact negatively on cash flows;
- the PTRM should include a mechanism such as an X factor for smoothing revenue; and
- the format and data used in the PTRM may be a precursor to the template of future reporting requirements.

Similarly ENERGEX supports the use of the TNSP RFM as the basis of the DNSP RFM but seeks clarification on the following issues:

- the different indexation methodology of the RAB in the RFM, PTRM and ENERGEX’s current regulatory framework;
- how and when the RAB values in the RFM and PTRM will be aligned; and
- on page 15 of the issues paper, the AER stated that *“S6.2.1 (e) (5) allows the DNSP to propose regulatory or actual depreciation (as it relates to forecast or actual capital expenditure respectively)”*. ENERGEX’s understanding was that all depreciation in the RFM was on a regulatory basis albeit <u>actual regulatory</u> or <u>forecast regulatory</u> depreciation.

In principle ENERGEX supports a similar Cost Allocation Methodology (CAM) approach to that used for TNSPs and is encouraged by the AER’s view that the CAM is a ‘living document’.

In relation to the various incentive schemes, ENERGEX has some concerns with the additional complexity and regulatory reporting burden on both DNSPs and the AER, arising from the implementation of the various schemes. ENERGEX believes that a co-operative and well considered approach on all related issues (including the interaction between the schemes) is required when developing the schemes.

In relation to the EBSS ENERGEX supports the principle of encouraging efficiency gains and of balancing the interests of customers and network operators. However, ENERGEX is concerned that a symmetrical scheme does not acknowledge the inherent penalties already built into the regulatory framework.

Changes from a DNSP's current regulatory reporting requirements should be transitioned over a period of time to limit the impact on financial and administrative resources. In implementing changes the AER should be cognisant that current systems have been established to ensure compliance with the DNSP's current regulatory obligations. Reporting to duplicate regulators in substantially different formats could result in costly modifications to systems and processes. Other legislative reporting requirements on the DNSP must also be considered so as to ensure reporting does not become a costly and cumbersome administrative exercise.

Detailed Response

ENERGEX's detailed response to the Guidelines, models and schemes Issues Paper is outlined in the table below.

Post Tax Revenue Model (PTRM)	
2.1.1: Basis and policy objectives ***The AER seeks comment on whether other rule provisions exist that are relevant to developing the PTRM for electricity distribution.*** ***Comments are also invited on whether the provisions mentioned here may require a different approach or have different meaning in the context of distribution and transmission regulation.***	The issues paper refers to S6.2.3 when discussing the roll forward of the Regulatory Asset Base (RAB) for the PTRM. ENERGEX believes that the method discussed in S6.2.3 is only applicable to the RFM model as the PTRM incorporates an inflation adjustment on the Opening RAB. References to inflation adjustments should specify whether it is forecast or actual inflation to be applied. Actual increases in relation to capital assets have been in excess of CPI and the QCA's indexation rate (based on government bonds). ENERGEX requests that the PTRM inflation rate be more reflective of the actual cost elements of its RAB. Discussion in the issues paper is primarily confined to the topic of depreciation (Clause 6.5.5(b)). When developing the PTRM the rules require the AER to also have regard to: • Return on Capital (Clause 6.5.2); • Estimated cost of corporate income tax (Clause 6.5.3); • Forecast capital expenditure (Clause 6.5.7); and • The X factor (Clause 6.5.9). Clause 6.4.3 states that the various components of the Annual Revenue Requirement. One of these components is listed as "estimated cost of corporate income tax". ENERGEX seeks clarification on the basis of the estimated cost (i.e. accrual or cash basis) and the methodology and assumptions underpinning its calculation.

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<td>2.1.2: Consistency between the PTRM for transmission and distribution regulation

The AER seeks comment on whether the PTRM developed for electricity transmission provides a suitable basis for distribution regulation. If not, what particular features or aspects of the PTRM need to be amended?</td>
<td>ENERGEX supports using the TNSP model to form the basis of the DNSP model but notes the following:

DNSPs have a more varied mix of capital assets and projects than TNSPs. ENERGEX requests that DNSP models be expanded to incorporate up to 50 asset categories. This flexibility will ensure ENERGEX can continue to meet its current regulatory requirements whilst at the same time begin preparations for the new regulatory requirements;
the return of asset and return on asset calculations are a departure from current regulatory arrangements under the QCA. The differences are as follows:

the PTRM does not allow for a return of asset on capitalised assets until the year following their commissioning. The PTRM does apply a timing adjustment to compensate for the lag; however the change will still have a negative impact on ENERGEX’s cash flows. The models should be adjusted to ensure the return of asset more accurately reflects the use and depreciation of the asset in accordance with the accounting standard AASB116; and
under current regulatory arrangements return on assets calculation is based on the indexed Opening RAB plus half of the current year’s capital expenditure. The PTRM calculation for return on assets is on the indexed Opening RAB only. This change will have a negative impact on cash flow.

the Rules allow for a hybrid form of price control and various categories of services. ENERGEX seeks clarification on how this would be accommodated in the models and guidelines; and
models need to accommodate capital assets that may become stranded, be deemed inefficient during their standard life, or that change status for regulatory purposes. If the models could accommodate this it would significantly reduce systems complications.
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<td>2.1.3.1: Capital contributions

The AER seeks comment on how the PTRM could be modified to recognise the treatment of capital contributions, or whether it may be more suitable to deal with this during reset processes.</td>
<td>Given the varied treatment of capital contributions by distributors, it is more appropriate to deal with this issue during the regulatory reset.</td>
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2.1.3.2: Cash-flow timing issues ***Do the PTRM's current timing assumptions result in any systematic bias in favour of service providers? If so, is there merit in considering modifications to the PTRM to remove this bias, for example, in the form of present value adjustments discussed here?*** ***To what extent would these adjustments increase the administrative burden and complexity of the modelling?***	ENERGEX considers the timing assumptions in relation to operating expenditure (year end) and capital expenditure (mid year) cash-flows to be pragmatic and suggests that any bias in favour of either the service provider or service recipients does not warrant the additional administrative burden and complexity of modelling. ENERGEX's concern with cashflows is in relation to the change in regulatory timing in recognising a return on or commencing depreciation on capital expenditure. These timing changes will have a considerable cashflow impact.
2.1.3.3: Forms of control **Stakeholders are invited to comment on the benefit of incorporating indicative X factor calculations in the PTRM under common forms of price control, namely revenue caps (as per the existing PTRM), weighted average price caps, and revenue yields.**	Regardless of the form of price control, a DNSP must still establish the building block and consider price impacts when determining its revenue requirement. Incorporating indicative X factor calculations into the model would be beneficial to distributors in the determination of the revenue requirement.
2.1.4: Linkages with information requirements ***Stakeholders are invited to comment on other likely information requirements associated with the PTRM.***	ENERGEX is concerned that the format of information reported on within the PTRM may form the basis of continued regulatory performance reporting without further consultation with the DNSP. Consideration needs to be given to the level of detail provided in the PTRM when compared to the level of information readily accessible for regular reporting to the AER. DNSPs have developed reporting frameworks to enable compliance with current regulatory reporting requirements. These requirements will still need to be met whilst the DNSP transitions to the new regulator's reporting requirements. Whilst the PTRM tax calculation may not be a change from the current QCA methodology, it should be noted that the PTRM's tax calculation will give rise to timing differences between the PTRM and corporate tax practices. The PTRM does not reflect true tax depreciation given the calculation is essentially based on accounting concepts and values.

Roll Forward Model (RFM)	
2.2.1: Basis and policy objectives ***The AER seeks comment on whether other rule provisions exist that are relevant to developing the RFM for electricity distribution. Comments are also invited on whether the provisions mentioned here may require a different approach or have different meaning in the context of distribution and transmission regulation.***	The guideline document mentions that Clause 6.5.1(e) (3) requires the RAB to be adjusted for actual inflation and S6.2.3 (4) also discusses adjusting the RAB for inflation. These clauses need clarification in relation to the method of inflation as the model does not actually apply inflation to the RAB but rather reduces depreciation by an inflation component (i.e. deducting regulatory depreciation from the RAB). The AER should also have regard to Return on capital (Clause 6.5.2), Estimated cost of corporate income tax (Clause 6.5.3) and Forecast capital expenditure (Clause 6.5.7) when developing the RFM.
2.2.2: Consistency between the RFM for transmission and distribution regulation ***Stakeholders are invited to comment on whether there are any impediments to using the AER's transmission RFM as a basis for the distribution model.***	In principle ENERGEX supports the use of the TNSP model as the basis for the DNSP model but notes several issues of concern: • DNSPs have a more varied mix of capital assets and projects than TNSPs. ENERGEX requests that DNSP models be expanded to incorporate up to 50 asset categories. This will ensure ENERGEX can continue to meet its current regulatory requirements whilst preparing for new regulatory requirements; • ENERGEX notes the method of rolling forward the RAB in the RFM is a departure from current regulatory arrangements. Under the QCA's approach ENERGEX's Opening RAB is indexed and depreciation is calculated on the indexed base. It appears that indexation of the opening RAB in the AER's TNSP RFM is not explicitly identified and instead is a component of the regulatory depreciation calculation; and • the AER's PTRM inflates the opening RAB for revenue calculations and therefore the RAB derived from the RFM will differ from the RAB derived by the PTRM. By the end of the regulatory period the RAB calculations may be significantly different between the RFM and PTRM. ENERGEX seeks the AER's clarification on how and when the two values will be reconciled.

2.2.3: Distribution specific issues ***The AER invites comments on whether the adoption of existing models is appropriate and whether there are specific issues regarding these models, and current jurisdictional revenue determinations, that the AER needs to consider in performing its first round of roll-forward calculations in each jurisdiction.***	Regulatory reporting frameworks established by DNSPs to meet their current regulatory reporting requirements also need to be considered. Imprudent deviations from the current regulatory reporting requirements could result in costly and complex modifications to systems and processes in order to comply with both AER requirements and current regulatory requirements. Consideration also needs to be given to other legislative reporting requirements on the DNSP to ensure reporting requirements do not become a costly and cumbersome administrative exercise.

Cost Allocation Guidelines	
2.3.3: Linkages to other guidelines ***Written comments from interested parties are sought on the following:*** • ***Given the similarity between the respective NER provisions for transmission and distribution, to what extent should the AER adopt a similar approach to cost allocation between distribution and transmission businesses?*** • ***Are the proposed general principles discussed above for the provision of information for cost allocation in the distribution sector appropriate?*** • ***Should any other general principles and or requirements be reflected in the distribution cost allocation guidelines?***	The CAM should support business growth, organisational change and provide sufficient flexibility to accommodate the introduction or discontinuation of services. When approved changes are made to a CAM discretion should be exercised in relation to requests for the restatement of historical results due to the associated compliance costs. ENERGEX seeks clarification in regard to the level of detail to be specified in the CAM and the level of service segmentation that allocations should be made to. The level of service segmentation required will impact significantly on the actual operational administration costs associated with the CAM.

Efficiency Benefits Sharing Scheme (EBSS)	
2.4.2: Similarities with the approach to transmission networks ***Is it reasonable to apply to DNSPs an EBSS with the same general approach as the transmission EBSS?*** ***Are there any significant differences between transmission and distribution businesses that would require a different general approach?***	ENERGEX is concerned with the application of EBSS on overspending of operating expenditure. Regulated revenue is set based on forecast operating expenditure that has been assessed as efficient by the AER. Any variation to the forecast operating expenditure does not alter the pre-determined regulated revenue. When a DNSP spends additional operating expenditure it results in reduced profits to the DNSP and its shareholders. The additional operating expenditure is funded by the DNSP without receiving any compensation or additional charge to the customer. On the other hand, the application of an EBSS scheme on efficiency gains in operating expenditure is supported on the basis that this will flow through as additional profits to the DNSP and its shareholders. Customers of the DNSP should benefit from efficiency gains achieved by the DNSP. Hence any EBSS on operating expenditure should not be symmetrical as the DNSP has already incurred a penalty by virtue of the additional operating expenditure spent. Any penalty arising from an EBSS would result in the DNSP and its shareholders incurring double penalisation. It should also be noted that over time marginal efficiency gains will diminish and will not be sufficient to warrant the associated costs of an efficiency scheme. ENERGEX has obligations through the EDSD recommendations that impact on its operating and capital expenditure requirements. The transitional arrangements require the AER to have regard to these obligations.

2.4.5: Nature of capital expenditure ***Would the application of an EBSS to capital expenditure yield sufficient benefits to consumers to offset the risk of windfall gains and losses?*** ***Could forecasts and/or actuals be adjusted ex post to reduce the risk of windfall gains and losses to acceptable levels?***	Please refer to ENERGEX's response under 'Other issues regarding inclusion of capital expenditure' (Reference 2.4.8).
2.4.6: Incentives to defer capital expenditure ***Would the application of an EBSS to capital expenditure provide inappropriate incentives to delay capital expenditure?***	Please refer to ENERGEX's response under 'Other issues regarding inclusion of capital expenditure' (Reference 2.4.8).
2.4.7: Impact of EBSS for incentives for demand side response and distributed generation ***Would the application of an EBSS to only opex materially impact DNSPs' incentives to undertake demand side responses and invest in distributed generation?***	Where operating expenditure for a demand-side solution is more prudent and efficient than spending capital expenditure, a DNSP should have an incentive to receive the same allowance as if a supply side investment was made. A DNSP should not be penalised for choosing a demand side response over a supply side response where the former is more efficient and prudent. On this basis an EBSS should exclude operating expenditure in relation to demand side responses. Whilst ENERGEX expects the quantum of demand side responses to grow in the next regulatory period, this area is still in the developmental stage and is therefore challenging to forecast with any degree of accuracy.

2.4.8: Other issues regarding inclusion of capital expenditure ***Are the incentives for efficient capital expenditure in the broader regulatory framework sufficient or is there also a need for an EBSS that incorporates capital expenditure?*** ***How would the exclusion of capital expenditure from the EBSS affect the overall regulatory incentives faced by DNSPs?*** ***In considering whether or not it is appropriate to include capital expenditure in the EBSS for distribution networks, what issues should the AER consider in addition to those discussed in this issues paper?***	ENERGEX does not see the rationale to apply an EBSS on capital expenditure. In an ex-ante framework, a DNSP capital expenditure overspend is already penalised by virtue of the foregone return on the additional capital expenditure during the regulatory period. The business forfeits revenues that could have been earned on that capital expenditure during the current regulatory period. If an EBSS was also applied on capital expenditure overspend then the DNSP would be penalised twice for spending what they considered to be prudent capital expenditure to manage their network. The same argument applies for underspending capital expenditure where the DNSP could potentially be rewarded at least twice or even three times as stated in the issues paper.
2.4.9: Treatment of distribution losses ***Is there any evidence available showing that the current level of distribution losses is significantly greater than the economically efficient level?*** ***If a distribution loss scheme is found necessary, would either of the Ofgem or IPART schemes be appropriate given the requirements of the NER? If not, what would be the best form of scheme?***	ENERGEX encourages the principle of reducing distribution losses but does not consider them to be significantly greater than the economically efficient level. As such ENERGEX does not believe further complications to this scheme or another scheme are warranted but is willing to work with the regulator to find a more appropriate mechanism for ensuring DNSPs are encouraged to reduce distribution loss factors.

2.4.10: Linkages with information requirements ***Is it reasonable to require DNSPs to provide the proposed information? Is there any further information that DNSPs should provide to assist in achieving the objectives of the scheme?***	The AER would need to ensure that the benefits of any additional data or information requirements, above those already required of the DNSP outweigh the additional compliance and administrative costs that the DNSP would incur.