TransGrid Revenue Proposal 2018/19 – 2022/23

Appendix J

Frontier Economics:

Opex forecast starting point – technical advice

Prescribed operating expenditure forecast starting point

A REPORT PREPARED FOR TRANSGRID

January 2017

Prescribed operating expenditure forecast starting point

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Executive summary

1 I, Rajat Sood, am an employee of Frontier Economics. I have been asked by TransGrid for advice on the appropriate method for determining the prescribed operating expenditure (opex) forecast starting point. My curriculum vitae is provided in an appendix to this report.

2 In particular, I have been asked for my view of the following:

> 1) Whether the way the Australian Energy Regulator's (AER's) Expenditure Forecast Assessment Guideline for Electricity Transmission (November 2013) (Forecast Guideline) uses base year underspend subtracted from the final year allowance as a forecast starting point is less accurate than potential alternatives, given that it relies partially on an old set of forecasts for the growth parameters (i.e. the old decision's allowance) when newer ones are available.
>
> 2) Whether a reasonable and more accurate alternative would be to use revealed base-year expenditure as the starting point of the forecast, and escalate this in accordance with the most recent available forecast of cost escalators (e.g. price, output growth, productivity, step changes) for each year within the forecast period (i.e. 2017/18 to 2022/23 assuming a 2016/17 revealed cost year).
>
> 3) Recognising that the estimation methodology for the Efficiency-Benefit Sharing Scheme (EBSS) carryover requires a special type of estimate for the final year due to the interactive nature of incentive payments with the previous allowance:
>
> > a. Would it be functionally correct for the EBSS calculation to use the existing methodology for final year estimation (i.e. final year expenditure estimate = final year allowance - base year underspend) whilst the forecast uses a different method?
> >
> > b. Are there any perverse or unintended consequences in adopting this approach?

Forecast accuracy

3 As I understand it, the alternative opex forecasting methodology that TransGrid is considering differs from the AER's methodology principally by avoiding the use of an estimated final year opex figure. Rather, the potential alternative methodology takes the TNSP's actual base year opex (adjusted for efficiencies if necessary) and escalates it by the (new) rate of change (RoC) determined at the same regulatory reset. This effectively means that the original RoC is retired and replaced one year (or two years, if the base year is the ante-penultimate year of the regulatory control period (RCP)) earlier than under the AER's methodology for the purposes of setting the opex forecast for the next RCP.

4 The 'accuracy' of an opex forecast can be understood in two ways:

- ***Ex post:*** Accuracy can refer to how close a forecast is to the actual outcome – in the present case, to outturn opex.
- ***Ex ante:*** Accuracy can refer to the extent to which a forecast incorporates all available relevant information at the time it is made.

5 In my view, the only meaningful way in which to interpret accuracy in the regulatory forecasting context is the *ex ante* approach.

6 Comparing the AER's opex forecasting methodology and the alternative being considered by TransGrid, the key differences appear to be that the AER's methodology:

- Uses less recent RoC estimates to escalate opex between the base year and the final year of the RCP prior to the RCP to which the forecast applies and
- Requires information about the step change components of final year forecast opex to ensure step change differences are properly treated.

7 Assuming differences between consecutive RCPs' RoCs are symmetrically distributed, imposing this risk on the TNSP does not seem to provide any benefit to customers and would seem only to raise TNSPs' efficient cost of financing. In my view, the AER's current methodology is likely to be less accurate and more prone to error, than the alternative, for no economic efficiency or other benefit.

Interaction with the Efficiency-Benefit Sharing Scheme

8 The EBSS Guideline notes that:

> The EBSS is intrinsically linked to the forecasting approach for opex.

9 The EBSS requires that at the time of a regulatory reset, the TNSP's incremental efficiency gains or losses in each year of the current RCP need to be calculated.

10 The question I have been asked to examine is whether it would be 'functionally correct' to use the alternative methodology raised by TransGrid for forecasting opex in the following RCP while continuing to use the existing methodology for final year estimation (i.e. final year expenditure estimate = final year allowance - base year underspend) for the EBSS calculation. I interpret 'functionally correct' to mean suitable or appropriate in light of the national electricity objective.

11 Under the alternative opex forecasting methodology, if the EBSS were to continue to use the existing methodology for final year actual opex estimation, any difference between RoC_n and RoC_{n+1} would be treated as a temporary gain or loss. Assuming the base year used to forecast the next RCP's opex is the penultimate year of the current RCP, this means that any RoC difference affects the TNSP as if it were a one-off efficiency gain or loss. Assuming the adoption of the ante-penultimate year as the base year, any RoC difference affects the TNSP as if it faced one single-year efficiency gain or loss and one two-year gain or loss. This means that the impact of the changes in RoCs is relatively limited.

12 Therefore, I consider that it would be appropriate to use the alternative opex forecasting methodology alongside the existing EBSS formula. Based on my analysis, this combination does not appear to give rise to any perverse incentives on TNSPs to either defer potential savings or to bring forward expenditures. It also appears to reduce the exposure of the TNSP to changes in RoCs that are out

of its control. This should help reduce TNSPs' exposure to risks that they are not well-placed to manage and hence help minimise their efficient cost of financing. This should, in turn, promote the national electricity objective.

1 Introduction

13 I, Rajat Sood, am an employee of Frontier Economics. I have been asked by TransGrid for advice on the appropriate method for determining the prescribed operating expenditure (opex) forecast starting point. My curriculum vitae is provided as an appendix to this report.

14 In particular, I have been asked for my view of the following:

> 1) Whether the way the Australian Energy Regulator's (AER's) Expenditure Forecast Assessment Guideline for Electricity Transmission (November 2013) (Forecast Guideline) uses base year underspend subtracted from the final year allowance as a forecast starting point is less accurate than potential alternatives, given that it relies partially on an old set of forecasts for the growth parameters (i.e. the old decision's allowance) when newer ones are available.
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> 2) Whether a reasonable and more accurate alternative would be to use revealed base-year expenditure as the starting point of the forecast, and escalate this in accordance with the most recent available forecast of cost escalators (e.g. price, output growth, productivity, step changes) for each year within the forecast period (i.e. 2017/18 to 2022/23 assuming a 2016/17 revealed cost year).
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> 3) Recognising that the estimation methodology for the Efficiency-Benefit Sharing Scheme (EBSS) carryover requires a special type of estimate for the final year due to the interactive nature of incentive payments with the previous allowance:
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> > a. Would it be functionally correct for the EBSS calculation to use the existing methodology for final year estimation (i.e. final year expenditure estimate = final year allowance - base year underspend) whilst the forecast uses a different method?
> >
> > b. Are there any perverse or unintended consequences in adopting this approach?

15 As a factual matter, I understand that TransGrid's final year allowance for its current regulatory control period (RCP) falls in real terms. This is because of a combination of opex-capex trade-off step changes that were not expected to apply in the final year, and a modest decrease in forecast line length in the AER's last decision.

16 I have read, understood and complied with the Federal Court of Australia Practice Note entitled, "Expert Evidence Practice Note", which commenced on 25 October 2016. The opinions I have expressed in this report are based wholly or substantially on my specialised knowledge.

17 This report responds to these questions and is structured as follows:

- Section 2 addresses questions 1 and 2.
- Section 3 addresses question 3(a) and (b).
- Appendix A reproduces the terms of reference provided to me by TransGrid.
- Appendix B provides several worked examples.

- Appendix C provides my curriculum vitae.

2 Forecast accuracy

18 The first two questions raised by TransGrid are as follows:

1) Whether the way the AER's Forecast Guideline uses base year underspend subtracted from the final year allowance as a forecast starting point is less accurate than potential alternatives, given that it relies partially on an old set of forecasts for the growth parameters (i.e. the old decision's allowance) when newer ones are available.

2) Whether a reasonable and more accurate alternative would be to use revealed base-year expenditure as the starting point of the forecast, and escalate this in accordance with the most recent available forecast of cost escalators (e.g. price, output growth, productivity, step changes) for each year within the forecast period (i.e. 2017/18 to 2022/23 assuming a 2016/17 revealed cost year).

19 These questions effectively require a comparison to be made between the AER's opex forecasting methodology (based on its Forecast Guideline) and the potential alternative methodology that TransGrid has raised. Accordingly, it is appropriate to address both questions jointly in the one section.

2.1 Background – regulatory provisions

20 This sub-section sets out my understanding of the relevant legislative and regulatory provisions relating to the forecasting of opex.

21 Section 7A of the National Electricity Law (NEL) sets out the revenue and pricing principles applicable to the economic regulation of transmission network service providers (TNSPs) in the NEM. Under 7A(2), TNSPs need to have a reasonable opportunity to recover at least their efficient costs in providing direct control services and meeting regulatory obligations.

22 Section 7 of the NEL sets out the national electricity objective. Section 16 in Part 3 of the NEL obliges the AER to perform its regulatory functions in a manner that is likely to promote the national electricity objective.

23 Under clause 6A.6.6 of the National Electricity Rules (NER), TNSPs are required to forecast opex for a RCP sufficient to meet a range of opex objectives. In determining whether to accept a TNSP's forecast opex, the AER needs to assess whether the TNSP's forecast reasonably reflects the opex criteria. The opex criteria, in turn, refer to the efficient costs of achieving the opex objectives and the costs that a prudent operator would require to achieve those objectives.

24 In making these assessments, the AER must have regard to, *inter alia*:

- The actual and expected opex of the TNSP during any preceding RCP and
- Whether the opex forecast is consistent with any applicable EBSS.

25 In addition to its Forecast Guideline, the AER has published an explanatory statement that provides more detail on its rationale for various elements of the Forecast Guideline (Explanatory Statement).[1]

2.1.1 AER's opex forecasting methodology

26 Under the AER's Forecast Guideline, forecast opex under the base-step-trend approach is as set out in Figure 1.

Figure 1: AER Base-Step-Trend Opex forecasting approach

$$Opex_t = \prod_{i=1}^{t}(1 + rate\ of\ change_i) \times \left(A_f^* - efficiency\ adjustment\right) \pm step\ changes_t$$

where:

- $rate\ of\ change_i$ is the annual percentage rate of change in year i
- A_f^* is the estimated actual opex in the final year of the preceding regulatory control period
- $efficiency\ adjustment$ is the difference between efficient opex and deemed final year opex
- $step\ changes_t$ is the determined step change in year t.

Source: Forecast Guideline, p.22.

27 Figure 1 shows that the AER will assess forecast opex for year **i** in RCP_t by taking:

- Estimated actual opex in the final year of RCP_{t-1} ($\mathbf{A}^*_f$)
- Making efficiency adjustments where estimated final year opex does not reasonably reflect the opex criteria in the NER
- Escalating (adjusted, if necessary) estimated final year opex by a rate of change (RoC) reflecting:
  - expected output growth
  - real input price growth and
  - productivity growth

  from the final year of RCP_{t-1} to the year of the forecast in RCP_t
- Adding or subtracting amounts for step changes.

28 The Forecast Guideline does not directly explain why the AER's approach to assessing forecast opex draws on an *estimate* of actual opex in the final year rather

[1] AER, *Explanatory Statement, Expenditure Forecast Assessment Guideline*, November 2013.

than the *known* actual opex in the base year. However, the Forecast Guideline does say that:[2]

> The EBSS requires an estimate of actual opex for the final year, which we do not typically know at the time of the final determination.

29 To ensure that the operation of the EBSS effects consistent efficiency incentives and the desired sharing ratio, final year opex is estimated as shown in Figure 2 below.

Figure 2: AER's approach to the estimation of final year actual opex

$$A_f^* = F_f - (F_b - A_b) + non\text{-}recurrent\ efficiency\ gain_b$$

where:

- A_f^* is the best estimate of actual opex for the final year of the preceding regulatory control period
- F_f is the determined opex allowance for the final year of the preceding regulatory control period
- F_b is the determined opex allowance for the base year
- A_b is the amount of actual opex in the base year
- $non\text{-}recurrent\ efficiency\ gain_b$ is the non-recurrent efficiency gain in the base year.

Source: Forecast Guideline, p.23.

30 Figure 2 shows that the AER will apply an estimate for final year opex ($\mathbf{A^*_f}$) by:

- Taking the opex allowance for the final year ($\mathbf{F_f}$)
- Subtracting the difference between the base year opex allowance ($\mathbf{F_b}$) and base year actual opex ($\mathbf{A_b}$) and
- Adding back any non-recurrent efficiency gains reflected in base year actual opex.[3]

31 But while an estimate of final year opex is required for the purposes of the EBSS – and recognising that this estimate will be corrected for in the following period – it is not clear why the same estimate must also be utilised as the starting point for assessing forecast opex for period n. This is particularly the case given that opex forecast on this basis *will not be adjusted* when actual final year opex becomes known (and will invariably be different to what was originally anticipated).

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2 Forecast Guideline, p.22.

3 Estimated non-recurrent efficiency gains made in the base year are also removed from the calculation of efficiency carryover benefits under the EBSS – see section 3.

32 One potential explanation is provided in the EBSS Guideline,[4] which states that estimated final year opex:[5]

> ...should be consistent with the estimate made when forecasting opex for the following period.

33 In the AER's Final decision on TransGrid's 2015-18 determination, the AER noted that:[6]

> Under the EBSS, service providers receive a financial reward for reducing their costs in the regulatory control period and a financial penalty for increasing their costs. The benefits of a reduction in opex flow through to consumers as long as base year opex is no higher than the opex incurred in that year. Similarly, the costs of an increase in opex flow through to consumers if base year opex is no lower than the opex incurred in that year. *If the starting point is not consistent with the EBSS, service providers could be excessively rewarded for efficiency gains or excessively penalised for efficiency losses in the prior regulatory control period.* [Emphasis added]

34 The question of whether the use of a particular opex forecast starting point is needed for the EBSS to function appropriately is taken up in section 3 below.

35 Nevertheless, on the issue of accuracy, it is far from obvious that the AER's opex forecasting methodology is optimal.

2.1.2 TransGrid's potential alternative opex forecasting methodology

36 As I understand it, the alternative opex forecasting methodology that TransGrid is considering differs from the AER's methodology principally by avoiding the use of an estimated final year opex figure. Rather, the alternative methodology takes the TNSP's actual base year opex (adjusted for efficiencies if necessary) and escalates it by the (new) RoC determined at the same regulatory reset. This effectively means that the original RoC is retired and replaced with an updated RoC one year (or two years, if the base year is the ante-penultimate year of the RCP) earlier than under the AER's methodology for the purposes of setting the opex forecast for the next RCP.

37 Consider the following example – assume:

- Prior to the start of the first RCP (RCP_1):

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4 AER, *Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, November 2013 (EBSS Guideline).

5 EBSS Guideline, p.6.

6 AER, *Final Decision, TransGrid transmission determination 2015-16 to 2017-18, Attachment 7 – Operating expenditure*, April 2015, p.7-15.

  - The (assumed constant) RoC used to forecast opex in RCP_1 is 2% per annum (RoC_1)
  - Forecast opex for the fourth year of RCP_1 (year 4) – being the selected base year for setting the RCP_2 opex allowance – is $100
  - For simplicity, actual opex in the fourth year of RCP_1 is also $100.
- The revised (constant) rate of change to set opex for RCP_2 (RoC_2) – determined in year 4 of RCP_1 – is 1% per annum.

38 In this example, forecast opex in RCP_2 is higher under the AER's methodology than under the alternative raised by TransGrid (see Table 1). The opposite may well occur.

39 I note that any difference in opex forecasts between the AER methodology and the alternative methodology that accrues may well be a ***permanent difference*** – in that, if differences between RoCs in consecutive RCPs are symmetrically distributed, there is no reason to expect that the gap between the forecasts will narrow in the future. If differences in RoCs are not symmetrically distributed – for example, if they are serially correlated – then the AER methodology will lead to forecasts that increasingly diverge from the alternative methodology over time.

Table 1: Comparison of AER and Alternative opex forecasting methodologies

Opex	RCP1		RCP2				
	4	5	1	2	3	4	5
RCP 1 Forecast	100	102					
Actual	100						
Rate of change RCP1: 2% RCP2: 1%							
AER		102	103.02	104.05	105.09	106.14	107.20
Alternative		-	102.01	103.03	104.06	105.10	106.15
Difference		**n/a**	**1.01**	**2.02**	**3.03**	**4.04**	**5.05**

2.1.3 Treatment of TransGrid's adjustments

40 Regarding the adjustments that have been made to TransGrid's final year allowance that will lead it to fall in real terms, the Forecast Guideline indicates that the AER will allow incremental changes above or below base year opex to account

for step changes – being changes in uncontrollable costs and efficient capex/opex trade-offs.[7] The Explanatory Statement notes that the AER will adjust base year opex "to account for changes in circumstances that will drive changes in opex in the forecast regulatory control period" including step changes, being efficient costs not reflected in base year opex.[8]

41 I would not expect the AER's practice to change if the opex forecasting methodology were changed to reflect the alternative raised by TransGrid. Both the AER's methodology and alternative methodology would likely account for TransGrid's adjustments similarly. I expect that under both methodologies, forecast opex for the subsequent RCP would be adjusted by adding or subtracting amounts to reflect the extent to which base year opex reflected *different* (or net as opposed to gross) step changes to those expected to apply in the following RCP.

2.2 Framework – what is forecast accuracy?

42 The 'accuracy' of an opex forecast can be understood in two ways:

- ***Ex post:*** Accuracy can refer to how close a forecast is to the actual outcome – in the present case, to outturn opex.
- ***Ex ante:*** Accuracy can refer to the extent to which a forecast incorporates all available relevant information at the time it is made.

43 I note the questions asked by TransGrid appear to refer to the second meaning. In my view, the only meaningful way in which to interpret accuracy in the regulatory forecasting context is the *ex ante* approach. The *ex post* accuracy or inaccuracy of a forecast will be influenced by variables that were unknown – or unknowable – at the time the forecast was made. As a result, it is difficult to make any robust inferences about the quality of a forecasting methodology from *ex post* accuracy unless – at a minimum – a particular methodology consistently yields more accurate predictions across a large number of RCPs.

44 Therefore, I interpret questions about the accuracy of alternative opex forecasting methodologies as involving an *ex ante* question:

> Within the context of the base-step-trend approach to forecasting opex, does the forecast incorporate, and appropriately utilise, all relevant information about a TNSP's future efficient costs?

7 Forecast Guideline, p.24; Explanatory Statement, p.62.

8 Explanatory Statement, p.11.

45 This is similar to how financial economists assess asset market efficiency – whether prevailing market prices reflect all available information about the value of asset.[9]

46 The question is thus which opex forecasting methodology –the AER's or the alternative raised by TransGrid – utilises a fuller or better information set, assuming both methodologies are to be applied at the same time and within the same base-step-trend framework. This can be examined by comparing the information set utilised by each methodology.

2.3 Respective information sets and usage

47 There is a broad degree of similarity regarding the information sets utilised by the AER's current forecasting methodology and the alternative raised by TransGrid. However, there are some important differences.

2.3.1 Rates of change

48 Both methodologies commence with an examination of a TNSP's actual opex in the base year used for a regulatory reset. This actual opex is also examined by the AER to determine whether it is reasonably efficient.

49 Under the AER's methodology, actual opex is compared to the forecast opex for the base year, which was determined at the previous regulatory reset. This comparison is used to derive a value for estimated final year opex by subtracting any base year underspend from (or adding any base year overspend to) forecast opex for the final year of the relevant RCP (RCP_t). Any base year inefficiency identified by the AER is then subtracted from estimated final year opex. This means that the AER methodology implicitly utilises the rate of change for RCP_t (RoC_t) to escalate base year opex to the final year. RoC_t is determined at the previous regulatory reset, typically five years earlier. The AER then uses RoC_{t+1} to escalate opex from the final year of RCP_t across RCP_{t+1}.

50 In the present case, the AER would be using a RoC set in 2014-15 to escalate actual opex in 2016-17 to 2017-18. It would then use a RoC set in 2017-18 to escalate estimated 2017-18 opex to the years 2018-19, 2019-20, 2020-21, 2021-22 and 2022-23.

51 Under the alternative methodology, the key difference is that actual opex in the base year is – subject to any downward adjustment for inefficiency – immediately escalated by the new rate of change determined in the base year (ie RoC_{t+1}) for the remainder of RCP_t and across RCP_{t+1}. This approach avoids reliance on RoC_t

[9] For example, see: http://review.chicagobooth.edu/magazine/winter-2013/eugene-fama-efficient-markets-and-the-nobel-prize

beyond the base year of RCP_t, given that that is when the new RoC (RoC_{t+1}) becomes available.

52 In the present case, this would mean using a RoC set in 2017-18 to escalate actual opex in 2016-17 to the years 2018-19, 2019-20, 2020-21, 2021-22 and 2022-23.

53 It is clear that the alternative opex forecasting methodology raised by TransGrid utilises more recent estimates of the appropriate RoC than the AER's approach. In my view, this implies that other things being equal, the alternative approach should be preferred on accuracy grounds. As noted above, any difference in opex forecasts that accrue may well be permanent and may cause forecasts using the AER's methodology to increasingly diverge from the more accurate alternative methodology over time.

2.3.2 Need for final year step change components

54 Another difference between the methodologies is that the AER methodology relies on forecast opex for the base year and final year of a RCP to derive estimated final year opex. Both of these values are set at the previous regulatory reset. Conversely, the alternative methodology does not require either of these values because it applies the new RoC directly to actual (efficient) base year opex.

55 In principle, assuming identical RoCs across RCPs, the AER's use of base year and final year opex forecasts should not affect the accuracy of the opex forecast for the following RCP. However, the use of these forecasts does complicate the process of dealing with step changes.

56 This is because the AER's methodology (as set out in Figure 1 above) assumes that the only difference between actual opex in the base year and in the final year is due to escalation of forecast opex in the base year to the final year by the original RoC (RoC_t). If there is a difference in step change values between base year opex and final year opex, the formulas in Figure 1 and Figure 2 do not explicitly describe how this would be taken into account.

57 What the AER would need to do in practice would be to identify the relevant step change components in each of the:

- Forecast opex in the base year
- Forecast opex in the final year
- Efficient opex in the subsequent RCP

58 Having derived these values, the AER would then be able to ensure that net step change differences between the opex forecasts for the base year, the final year and each of the years in the following RCP were properly accounted for and not omitted or double-counted.

59 Conversely, the alternative methodology avoids the need to take account of the step change component of forecast opex in the final year. This reduces the

complexity of ensuring step change differences are properly reflected in opex forecasts and should ensure that the forecasts are less prone to errors.

2.4 Implications for risk allocation / management

60 Comparing the AER's opex forecasting methodology and the alternative being considered by TransGrid, the key differences appear to be that the AER's methodology:

- Uses less recent RoC estimates to escalate opex between the base year and the final year of the RCP prior to the RCP to which the forecast applies and
- Requires information about the step change components of final year forecast opex to ensure step change differences are property treated.

61 Regarding the RoC estimates, under the AER's methodology, the TNSP bears the risk of managing the *permanent impact* of one (or potentially two or more) year's (years') differences between the RoC_t and RoC_{t+1} escalation factors. Remembering that RoC_{t+1} is more up-to-date, it is likely to better reflect changes in a TNSP's efficient opex between the base year and final year of a RCP than the RoC_t used in the AER's methodology.

62 Assuming differences between consecutive RCPs' RoCs are symmetrically distributed, imposing this risk on the TNSP does not seem to provide any benefit to customers and would seem only to raise TNSPs' efficient cost of financing.

63 Regarding the required information about final year step change components, this appears to insert a needless step into the forecasting process that will make it more prone to error. Both TNSPs and customers will share the risks that final year step change amounts are calculated incorrectly, omitted or double-counted.

2.5 Findings / Conclusions

64 In my view, the alternative opex forecasting methodology raised by TransGrid is more accurate than the AER's current methodology, from the only perspective that makes sense – an *ex ante* assessment.

65 The AER's current methodology is likely to be less accurate and more prone to error, for no economic efficiency or other benefit.

3 Interaction with the EBSS

66 The third question raised by TransGrid is as follows:

> 3) Recognising that the estimation methodology for the Efficiency-Benefit Sharing Scheme (EBSS) carryover requires a special type of estimate for the final year due to the interactive nature of incentive payments with the previous allowance:
>
> a. Would it be functionally correct for the EBSS calculation to use the existing methodology for final year estimation (i.e. final year expenditure estimate = final year allowance - base year underspend) whilst the forecast uses a different method?
>
> b. Are there any perverse or unintended consequences in adopting this approach?

67 This section responds to this question.

3.1 Background – regulatory provisions

68 Section 7A(3) of the NEL requires that a TNSP should be provided with effective incentives to promote economic efficiency with respect to, *inter alia*, the efficient provision of network services.

69 Clause 6A.6.5 of the NER obliges the AER to develop an efficiency-benefit sharing scheme that provides for a fair sharing of efficiency gains and losses derived from opex being less or more than forecast opex, respectively. A key requirement of the scheme is that it provides TNSPs with a *continuous* incentive to reduce opex.

70 The EBSS Guideline sets out how the AER intends to provide TNSPs with appropriate incentives to reduce opex.[10]

3.2 Interaction of opex forecast with the EBSS

71 The EBSS Guideline notes that:[11]

> The EBSS is intrinsically linked to the forecasting approach for opex.

72 The EBSS Guideline explains the operation of the scheme as follows:[12]

> - The regulatory regime provides for ex ante opex forecasts. The NSP keeps the benefit (or incurs the cost) of delivering actual opex lower (higher) than forecast opex in each year of a regulatory control period.

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10 AER, *Efficiency Benefit Sharing Scheme for Electricity Network Service Providers*, November 2013.

11 EBSS Guideline, p.4.

12 EBSS Guideline, p.5.

- The EBSS carries forward a NSP's incremental efficiency gains for the length of the carryover period. This carryover period length will typically be five years for a five year regulatory control period.
- The carryover amounts accrued in year i of period n + 1 will be the summation of the incremental efficiency gains in period n that are carried forward into year i.
- We add the carryover amounts as an additional 'building block' when setting the NSP's regulated revenue for the period n + 1.
- The actual opex incurred in the base year is used as the starting point for forecasting opex for period n + 1.
- Under this approach, the benefits of any increase or decrease in opex is shared approximately 30:70 between NSPs and consumers.

73 The EBSS requires that at the time of a regulatory reset, the TNSP's incremental efficiency gains or losses in each year of the current RCP need to be calculated.

74 The incremental efficiency gain in the second year through to the penultimate year of a RCP (RCP_n) is calculated as set out Figure 3, where:

- $\mathbf{I_{i,n}}$ refers to the incremental efficiency gain in year **i**, where i is any year in RCP_n except the first or the final year
- $\mathbf{F_{i,n}}$ refers to forecast opex in year i
- $\mathbf{A_{i,n}}$ refers to actual opex in year i
- $\mathbf{F_{i\text{-}1,n}}$ refers to forecast opex in year i-1 (ie the year prior to i)
- $\mathbf{A_{i,n}}$ refers to actual opex in year i-1.

Figure 3: Incremental efficiency gains in the second to penultimate years of a RCP

$$I_{i,n} = \left(F_{i,n} - A_{i,n}\right) - \left(F_{i-1,n} - A_{i-1,n}\right)$$

Source: EBSS Guideline, p.6.

75 Calculating the incremental efficiency gain in the final year of a RCP is more complicated because, as noted in section 2.1.1, actual final year opex is not known at the time of the regulatory reset. Therefore, the AER utilises an estimate of final year opex. See Figure 5 below, where:

- $\mathbf{I_{f,n}}$ refers to the incremental efficiency gain in the final year of RCP_n
- $\mathbf{F_{f,n}}$ refers to forecast opex in the final year of RCP_n
- $\mathbf{A^{*}_{f,n}}$ refers to estimated actual opex in the final year of RCP_n
- $\mathbf{F_{f\text{-}1,n}}$ refers to forecast opex in the penultimate year of RCP_n
- $\mathbf{A_{f\text{-}1,n}}$ refers to actual opex in the penultimate year of RCP_n.

Figure 4: Incremental efficiency gains in the final year of a RCP

$$I_{f,n} = (F_{f,n} - A^*_{f,n}) - (F_{f-1,n} - A_{f-1,n})$$

Source: EBSS Guideline, p.7.

76 The final year opex estimate is derived as set out in Figure 5, where:

- **$A^*_{f,n}$** refers to estimated final year opex in RCP_n
- **$F_{f,n}$** refers to the final year opex allowance in RCP_n
- **$F_{b,n}$** refers to the base year opex allowance in RCP_n
- **$A_{b,n}$** refers to base year actual opex in RCP_n.

Figure 5: AER's approach to the estimation of final year actual opex

$$A^*_{f,n} = F_{f,n} - (F_{b,n} - A_{b,n}) + \textit{non-recurrent efficiency gain}_{b,n}$$

Source: EBSS Guideline, p.7.

77 I note that this formula is effectively identical to the formula on page 23 of the Forecast Guideline, reproduced in Figure 2 above.

78 Calculating the incremental efficiency gain in the first year of a RCP is in a way less complicated than for the final year, because by the time of a regulatory reset, actual opex for the final year of the previous RCP (RCP_{n-1}) is known – see Figure 6.

Figure 6: Incremental efficiency gains in the first year of a RCP

$$I_{1,n} = (F_{1,n} - A_{1,n}) - [(F_{f,n-1} - A_{f,n-1}) - (F_{b,n-1} - A_{b,n-1})] - \textit{non-recurrent efficiency gain}_{b,n-1}$$

Where:

$I_{i,n}$ is the incremental efficiency gain in year i of period n

$F_{1,n}$ is forecast opex (subject to adjustments) in year 1 of period n

$A_{1,n}$ is actual opex (subject to adjustments) in year 1 of period n

$F_{f,n-1}$ is forecast opex (subject to adjustments) in the final year of period $n-1$

$A_{f,n-1}$ is actual opex (subject to adjustments) in the final year of period $n-1$

$F_{b,n-1}$ is forecast opex (subject to adjustments) in the base year of period $n-1$

$A_{b,n-1}$ is actual opex (subject to adjustments) in the base year of period $n-1$

$\textit{non-recurrent efficiency gain}_{b,n-1}$ is the adjustment made to base year opex used to forecast opex for period n to account for opex associated with one-off factors

Source: EBSS Guideline, p.6.

Interaction with the EBSS

79 The AER will make a number of adjustments to forecast or actual opex when calculating carryover amounts. In particular, the AER will exclude categories of opex not forecast using a single year revealed cost approach for RCP_{n+1} where doing so better achieves the requirements of the NER.[13]

3.3 Use of different opex methodologies

80 The question I have been asked to examine is whether it would be 'functionally correct' to use the alternative methodology raised by TransGrid for forecasting opex in the following RCP while continuing to use the existing methodology for final year estimation (i.e. final year expenditure estimate = final year allowance - base year underspend) for the EBSS calculation. I interpret 'functionally correct' to mean suitable or appropriate in light of the national electricity objective.

81 Based on my analysis, I consider it would be appropriate to:

- Continue to use the existing opex forecasts for RCP_n (based on the older RoC (RoC_n)) for the purposes of the EBSS,
- While using the alternative methodology for forecasting opex for RCP_{n+1} (using the new RoC (RoC_{n+1})).

82 As noted in section 2.4, the current AER opex forecasting methodology treats any value attributable to the use of RoC_n instead of the more recent RoC_{n+1} to escalate opex between the base year and the final year of RCP_n as a permanent gain or loss to the TNSP (and by extension, the opposite to the TNSPs customers). When combined with the existing EBSS, this means that the TNSP bears approximately 30%[14] of this value, but has no means of managing this risk.

83 If a TNSP makes a permanent final year opex saving or overrun that precisely offsets the impact of the RoC difference, the impact of the RoC difference cancels out. That is, the TNSP faces the same sharing ratio as it normally would on permanent opex savings or overruns.

84 Under the alternative opex forecasting methodology, if the EBSS were to continue to use the existing methodology for final year actual opex estimation, any difference between RoC_n and RoC_{n+1} would be treated as a temporary gain or loss. Assuming the base year used to forecast the next RCP's opex is the penultimate year of the current RCP, this means that any RoC difference affects the TNSP as if it were a one-off efficiency gain or loss. Assuming the adoption of the ante-penultimate year as the base year, any RoC difference affects the TNSP as if it faced one single-year efficiency gain or loss and one two-year gain or loss. This means that the impact of the changes in RoCs is relatively limited.

---

13 EBSS Guideline, p.7.

14 Assuming a 6% real discount rate and 5 year RCP.

85 I am also confident that the use of the alternative opex forecasting methodology alongside the existing EBSS formula would not, by comparison to the use of the AER's existing methodology (the 'Base case'), create perverse incentives for TNSPs to engage in inefficient behaviours, such as:

- Unnecessarily increasing opex in the base year ('Boost base year opex') or
- Unnecessarily bringing-forward opex from the year following the base year into the base year ('Bring-forward opex').

86 Appendix B provides worked examples showing how the financial penalty to TNSPs from engaging in either of these behaviours is the same, regardless of whether the methodology used to forecast opex for the next RCP is the:

- AER's existing methodology (see Figure 7, Figure 10 and Figure 13)
- Alternative methodology with a penultimate year base year (see Figure 8, Figure 11 and Figure 14) or
- Alternative methodology with an ante-penultimate base year (see Figure 9, Figure 12 and Figure 15).

87 Therefore, I consider that it would be appropriate to use the alternative opex forecasting methodology alongside the existing EBSS formula. Based on my analysis, this combination does not appear to give rise to any perverse incentives on TNSPs to either defer potential savings or to avoid making savings where they are available. It also appears to reduce the exposure of the TNSP to changes in RoCs that are out of its control. This should help reduce TNSPs' exposure to risks that they are not well-placed to manage and hence help minimise their efficient cost of financing. This should, in turn, promote the national electricity objective.

88 Appendix B below provides a series of worked examples, which all assume that RoC_n is nil and RoC_{n+1} is \$10 per year. The examples also assume no non-recurrent savings in the base year or step changes.

3.4 Findings / Conclusions

89 In my view, it would be appropriate to continue applying the EBSS by using the existing methodology for final year estimation of actual opex alongside the use of the alternative methodology for forecasting opex for the next RCP. This combination would expose the TNSP to approximately 30% of the one-off gain or loss arising from differences between RoC_n and RoC_{n+1}.

Appendix A – Terms of reference

TransGrid

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Rajat Sood
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Dear Rajat

Re: Terms of Reference for Operating Expenditure Forecast Starting Point

Background

TransGrid must submit an operating expenditure forecast as part of its revenue proposal to the AER. The forecast must be compliant with the National Electricity Law (NEL), which includes the National Electricity Objectives (NEO). The forecast must also comply with the National Electricity Rules (the Rules). These obligations include that TransGrid must forecast the operating expenditure it expects to incur in order to meet the operating expenditure objectives for the relevant regulatory control period. These are as follows:

> Meet or manage expected demand for prescribed transmission services in the period;
> Comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services;
> To the extent there is no applicable regulatory obligation or requirement in relation to:
> The quality, reliability or security of supply of prescribed transmission services; or
> The reliability or security of the transmission system through the supply of prescribed transmission services;

To the relevant extent:

> Maintain the quality, reliability and security of supply of prescribed transmission services; and
> Maintain the reliability and security of the transmission system through the supply of prescribed transmission services; and
> Maintain the safety of the transmission system through the supply of prescribed transmission services.

TransGrid's operating expenditure forecast must also:

> Comply with the requirements of any relevant regulatory information instrument.
> Only be for prescribed transmission services in accordance with the principals and policies set out in TransGrid's cost allocation methodology.
> Include the total of the forecast operating expenditure for the relevant regulatory control period
> Include the forecast operating expenditure for each regulatory year of the relevant control period

For the purpose of meeting these obligations, TransGrid would like to align its prescribed operating expenditure forecast as much as possible with the Australian Energy Regulator's (AER) Expenditure Forecast Assessment Guideline for Electricity Transmission (November 2013) – referred to as the guideline. However, there is an aspect of the forecasting methodology set out in the guideline that TransGrid would like to investigate the accuracy of. This concerns the estimation method for the final year operating expenditure, set out on page 23 of the guideline.

NSW Electricity Networks Operations Pty Ltd, ACN 609 169 959, as trustee for NSW Electricity Operations Trust

www.transgrid.com.au

Terms of Reference

TransGrid would like to know Frontier Economics' view of the following:

> Whether the way the guideline uses base year underspend subtracted from final year allowance as a forecast starting point is less accurate than potential alternatives, given that it relies partially on an old set of forecasts for the growth parameters (i.e. the old decision's allowance) when newer ones are available.

> Whether a reasonable and more accurate alternative would be to use revealed base-year expenditure as the starting point of the forecast, and escalate this in accordance with the most recent available forecast of cost escalators (e.g. price, output growth, productivity, step changes) for each year within the forecast period (i.e. 2017/18 to 2022/23 assuming a 2016/17 revealed cost year).

> Recognising that the estimation methodology for the EBSS carryover requires a special type of estimate for the final year due to the interactive nature of incentive payments with the previous allowance:

- Would it be functionally correct for the EBSS calculation to use the existing methodology for final year estimation (i.e. final year expenditure estimate = final year allowance - base year underspend) whilst the forecast uses a different method?
- Are there any perverse or unintended consequences in adopting this approach?

Yours faithfully

Shane Tennett
Regulatory Opex Manager

Appendix B – Worked examples (assuming RoC1=0, RoC2=10 and 6% discount rate)

Figure 7: Base case: AER existing opex forecasting methodology and existing EBSS

		RCP	1					2					3					NPV for TNSP
		Yr	1	2	3	4	5	1	2	3	4	5	1	2	3	4	5	
AER	Forecast		100	100	100	100	100	110	120	130	140	150	170	180	190	200	210	
	Actual		100	100	100	100	110	120	130	140	150	160	170	180	190	200	210	
	Saving		0	0	0	0	-10	-10	-10	-10	-10	-10	0	0	0	0	0	
	Incr sav		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	EBSS																	
	Carryover	1		0	0	0	0	0	0	0	0	0	0	0	0	0	0	
		2			0	0	0	0	0	0	0	0	0	0	0	0	0	
		3				0	0	0	0	0	0	0	0	0	0	0	0	
		4					0	0	0	0	0	0	0	0	0	0	0	
		5						0	0	0	0	0	0	0	0	0	0	
		Sum	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	Total allowance		100	100	100	100	100	110	120	130	140	150	170	180	190	200	210	
	Actual		100	100	100	100	110	120	130	140	150	160	170	180	190	200	210	
	Gain/Loss		**0**	**0**	**0**	**0**	**-10**	**-10**	**-10**	**-10**	**-10**	**-10**	**0**	**0**	**0**	**0**	**0**	
	Benefit to TNSP		0	0	0	0	-10	-10	-10	-10	-10	-10	0	0	0	0	0	-49.173
	Disc		1.191	1.1236	1.06	1	0.9434	0.89	0.8396	0.7921	0.7473	0.705	0.6651	0.6274	0.5919	0.5584	0.5268	

Source: Frontier Economics

Using the AER's existing opex forecasting methodology and the existing efficiency benefit sharing scheme (EBSS), this example shows the financial impact on a TNSP of an increase in the opex rate of change (RoC). The original RoC (determined prior to the first regulatory control period (RCP1)) is assumed to be zero – that is, real opex is assumed to remain flat. The updated RoC (determined in year 4 of RCP1) is assumed to be $10 per annum.

Under these conditions, the TNSP faces a net present value (NPV) loss of $49.17 discounted to year 4 of RCP1 (this being the time when the decision to use the original RoC is made).

Figure 8: Base case: Alternative opex forecasting methodology with penultimate year base year and existing EBSS

		RCP	1					2					3					NPV for TNSP
		Yr	1	2	3	4	5	1	2	3	4	5	1	2	3	4	5	
Alternative	Forecast		100	100	100	100	100	120	130	140	150	160	170	180	190	200	210	
Base Year = Penultimate year [4th year]	Actual		100	100	100	100	110	120	130	140	150	160	170	180	190	200	210	
	Saving		0	0	0	0	-10	0	0	0	0	0	0	0	0	0	0	
	Incr sav		0	0	0	0	0	10	0	0	0	0	0	0	0	0	0	
	EBSS																	
	Carryover	1		0	0	0	0	0	10	10	10	10	10	0	0	0	0	
		2			0	0	0	0	0	0	0	0	0	0	0	0	0	
		3				0	0	0	0	0	0	0	0	0	0	0	0	
		4					0	0	0	0	0	0	0	0	0	0	0	
		5						0	0	0	0	0	0	0	0	0	0	
		Sum	0	0	0	0	0	0	0	0	0	0	10	0	0	0	0	
	Total allowance		100	100	100	100	100	120	130	140	150	160	180	180	190	200	210	
	Actual		100	100	100	100	110	120	130	140	150	160	170	180	190	200	210	
	Gain/Loss		**0**	**0**	**0**	**0**	**-10**	**0**	**0**	**0**	**0**	**0**	**10**	**0**	**0**	**0**	**0**	
	Benefit to TNSP		0	0	0	0	-10	0	0	0	0	0	10	0	0	0	0	-2.783
	Disc		1.191	1.1236	1.06	1	0.9434	0.89	0.8396	0.7921	0.7473	0.705	0.6651	0.6274	0.5919	0.5584	0.5268	

Source: Frontier Economics

Using the alternative opex forecasting methodology (with a penultimate base year) and the existing EBSS, this example shows the financial impact on a TNSP of an increase in the opex RoC. The original RoC is assumed to be zero, whereas the updated RoC is assumed to be $10 per annum.

Under these conditions, the TNSP faces a NPV loss of $2.78 discounted to year 4 of RCP1. In my view, it is appropriate that this loss is smaller than the loss the TNSP faces under the AER's existing opex forecasting methodology (see Figure 7) because the increase in the RoC is out of the TNSP's control.

Appendix B – Worked examples (assuming RoC1=0, RoC2=10 and 6% discount rate)

Figure 9: Base case: Alternative opex forecasting methodology with ante-penultimate year base year and existing EBSS

			RCP	1					2					3					NPV for TNSP
			Yr	1	2	3	4	5	1	2	3	4	5	1	2	3	4	5	
Alternative	Forecast			100	100	100	100	100	130	140	150	160	170	180	190	200	210	220	
Base Year = Ante-penultimate year [3rd year]	Actual			100	100	100	110	120	130	140	150	160	170	180	190	200	210	220	
	Saving			0	0	0	-10	-20	0	0	0	0	0	0	0	0	0	0	
	Incr sav			0	0	0	-10	10	20	0	0	0	0	0	0	0	0	0	
	EBSS																		
	Carryover	1			0	0	0	0	0	20	20	20	20	20	0	0	0	0	
		2				0	0	0	0	0	0	0	0	0	0	0	0	0	
		3					0	0	0	0	0	0	0	0	0	0	0	0	
		4						-10	-10	-10	-10	-10	0	0	0	0	0	0	
		5							10	10	10	10	10	0	0	0	0	0	
		Sum		0	0	0	0	0	0	0	0	0	10	20	0	0	0	0	
	Total allowance			100	100	100	100	100	130	140	150	160	180	200	190	200	210	220	
	Actual			100	100	100	110	120	130	140	150	160	170	180	190	200	210	220	
	Gain/Loss			**0**	**0**	**0**	**-10**	**-20**	**0**	**0**	**0**	**0**	**10**	**20**	**0**	**0**	**0**	**0**	
	Benefit to TNSP			0	0	0	-10	-20	0	0	0	0	10	20	0	0	0	0	-8.035072501
	Disc			1.1236	1.06	1	0.9434	0.89	0.8396	0.7921	0.7473	0.705	0.6651	0.6274	0.5919	0.5584	0.5268	0.497	

Source: Frontier Economics

Using the alternative opex forecasting methodology (with an ante-penultimate base year) and the existing EBSS, this example shows the financial impact on a TNSP of an increase in the opex RoC. The original RoC is assumed to be zero, whereas the updated RoC is assumed to be $10 per annum.

Under these conditions, the TNSP faces a NPV loss of $8.04 discounted to year 4 of RCP1. In my view, it is appropriate that this loss is smaller than the loss the TNSP faces under the AER's existing opex forecasting methodology (see Figure 7) because the increase in the RoC is out of the TNSP's control.

Appendix B – Worked examples (assuming RoC1=0, RoC2=10 and 6% discount rate)

Figure 10: Boost base year opex: AER existing opex forecasting methodology and existing EBSS

			1					2					3					NPV for TNSP	Change from BC
		RCP	1					2					3						
		Yr	1	2	3	4	5	1	2	3	4	5	1	2	3	4	5		
AER	Forecast		100	100	100	100	100	120	130	140	150	160	170	180	190	200	210		
	Actual		100	100	100	110	110	120	130	140	150	160	170	180	190	200	210		
	Saving		0	0	0	-10	-10	0	0	0	0	0	0	0	0	0	0		
	Incr sav		0	0	0	-10	0	0	0	0	0	0	0	0	0	0	0		
	EBSS																		
	Carryover	1		0	0	0	0	0	0	0	0	0	0	0	0	0	0		
		2			0	0	0	0	0	0	0	0	0	0	0	0	0		
		3				0	0	0	0	0	0	0	0	0	0	0	0		
		4					-10	-10	-10	-10	-10	0	0	0	0	0	0		
		5						0	0	0	0	0	0	0	0	0	0		
		Sum	0	0	0	0	0	-10	-10	-10	-10	0	0	0	0	0	0		
	Total allowance		100	100	100	100	100	110	120	130	140	160	170	180	190	200	210		
	Actual		100	100	100	110	110	120	130	140	150	160	170	180	190	200	210		
	Gain/Loss		**0**	**0**	**0**	**-10**	**-10**	**-10**	**-10**	**-10**	**-10**	**0**	**0**	**0**	**0**	**0**	**0**		
	Benefit to TNSP		0	0	0	-10	-10	-10	-10	-10	-10	0	0	0	0	0	0	-52.124	-2.950
	Disc		1.191	1.1236	1.06	1	0.9434	0.89	0.8396	0.7921	0.7473	0.705	0.6651	0.6274	0.5919	0.5584	0.5268		

Source: Frontier Economics

Using the AER's existing opex forecasting methodology and the existing EBSS, this example shows the financial impact on a TNSP of boosting its opex in the base year used to forecast opex for the second RCP (RCP2), while experiencing an increase in its opex RoC from $0 to $10 per annum.

Under these conditions, the TNSP faces a NPV loss of $52.12 discounted to year 4 of RCP1. This is $2.95 greater than under the base case described in Figure 7 (where there is no boost to base year opex). The present example shows that the TNSP incurs a NPV penalty of approximately 30% ($2.95 out of an overall NPV loss of $10) from artificially boosting its base year opex.

Appendix B – Worked examples (assuming RoC1=0, RoC2=10 and 6% discount rate)

Figure 11: Boost base year opex: Alternative opex forecasting methodology with penultimate year base year and existing EBSS

		RCP	1					2					3					NPV for TNSP	Change from BC
		Yr	1	2	3	4	5	1	2	3	4	5	1	2	3	4	5		
Alternative	Forecast		100	100	100	100	100	130	140	150	160	170	170	180	190	200	210		
Base Year = Penultimate year [4th year]	Actual		100	100	100	110	110	120	130	140	150	160	170	180	190	200	210		
	Saving		0	0	0	-10	-10	10	10	10	10	10	0	0	0	0	0		
	Incr sav		0	0	0	-10	0	10	0	0	0	0	0	0	0	0	0		
	EBSS																		
	Carryover	1		0	0	0	0	0	10	10	10	10	10	0	0	0	0		
		2			0	0	0	0	0	0	0	0	0	0	0	0	0		
		3				0	0	0	0	0	0	0	0	0	0	0	0		
		4					-10	-10	-10	-10	-10	0	0	0	0	0	0		
		5						0	0	0	0	0	0	0	0	0	0		
		Sum	0	0	0	0	0	-10	-10	-10	-10	0	10	0	0	0	0		
	Total allowance		100	100	100	100	100	120	130	140	150	170	180	180	190	200	210		
	Actual		100	100	100	110	110	120	130	140	150	160	170	180	190	200	210		
	Gain/Loss		**0**	**0**	**0**	**-10**	**-10**	**0**	**0**	**0**	**0**	**10**	**10**	**0**	**0**	**0**	**0**		
	Benefit to TNSP		0	0	0	-10	-10	0	0	0	0	10	10	0	0	0	0	-5.734	-2.950
	Disc		1.191	1.1236	1.06	1	0.9434	0.89	0.8396	0.7921	0.7473	0.705	0.6651	0.6274	0.5919	0.5584	0.5268		

Source: Frontier Economics

Using the alternative opex forecasting methodology (with a penultimate base year) and the existing EBSS, this example shows the financial impact on a TNSP of boosting its opex in the base year used to forecast opex for RCP2, while experiencing an increase in its opex RoC from $0 to $10 per annum.

Under these conditions, the TNSP faces a NPV loss of $5.73 discounted to year 4 of RCP1. This is $2.95 greater than under the base case described in Figure 8 (where there is no boost to base year opex). The present example shows that the TNSP incurs a NPV penalty of approximately 30% from artificially boosting its base year opex, just as it does under the AER's existing opex forecasting methodology. This means that the use of the alternative opex forecasting methodology together with the existing EBSS does not create perverse incentives to boost base year opex.

Appendix B – Worked examples (assuming RoC1=0, RoC2=10 and 6% discount rate)

Figure 12: Boost base year opex: Alternative opex forecasting methodology with ante-penultimate year base year and existing EBSS

		RCP	1					2					3					NPV for TNSP	Change from BC
		Yr	1	2	3	4	5	1	2	3	4	5	1	2	3	4	5		
Alternative	Forecast		100	100	100	100	100	140	150	160	170	180	180	190	200	210	220		
Base Year = Ante-penultimate year [3rd year]	Actual		100	100	110	110	120	130	140	150	160	170	180	190	200	210	220		
	Saving		0	0	-10	-10	-20	10	10	10	10	10	0	0	0	0	0		
	Incr sav		0	0	-10	0	0	20	0	0	0	0	0	0	0	0	0		
	EBSS																		
	Carryover	1		0	0	0	0	0	20	20	20	20	20	0	0	0	0		
		2			0	0	0	0	0	0	0	0	0	0	0	0	0		
		3				-10	-10	-10	-10	-10	0	0	0	0	0	0	0		
		4					0	0	0	0	0	0	0	0	0	0	0		
		5						0	0	0	0	0	0	0	0	0	0		
		Sum	0	0	0	0	0	-10	-10	-10	0	0	20	0	0	0	0		
	Total allowance		100	100	100	100	100	130	140	150	170	180	200	190	200	210	220		
	Actual		100	100	110	110	120	130	140	150	160	170	180	190	200	210	220		
	Gain/Loss		**0**	**0**	**-10**	**-10**	**-20**	**0**	**0**	**0**	**10**	**10**	**20**	**0**	**0**	**0**	**0**		
	Benefit to TNSP		0	0	-10	-10	-20	0	0	0	10	10	20	0	0	0	0	-10.985	-2.950
	Disc		1.1236	1.06	1	0.9434	0.89	0.8396	0.7921	0.7473	0.705	0.6651	0.6274	0.5919	0.5584	0.5268	0.497		

Source: Frontier Economics

Using the alternative opex forecasting methodology (with an ante-penultimate base year) and the existing EBSS, this example shows the financial impact on a TNSP of boosting its opex in the base year used to forecast opex for RCP2, while experiencing an increase in its opex RoC from $0 to $10 per annum.

Under these conditions, the TNSP faces a NPV loss of $10.99 discounted to year 4 of RCP1. This is $2.95 greater than under the base case described in Figure 9 (where there is no boost to base year opex). The present example shows that the TNSP incurs a NPV penalty of approximately 30% from artificially boosting its base year opex, just as it does under the AER's existing opex forecasting methodology. This means that the use of the alternative opex forecasting methodology together with the existing EBSS does not create perverse incentives to boost base year opex.

Appendix B – Worked examples (assuming RoC1=0, RoC2=10 and 6% discount rate)

Figure 13: Bring-forward opex: AER existing opex forecasting methodology and existing EBSS

																		NPV for TNSP	Change from BC
		RCP	1					2					3						
		Yr	1	2	3	4	5	1	2	3	4	5	1	2	3	4	5		
AER	Forecast		100	100	100	100	100	120	130	140	150	160	170	180	190	200	210		
	Actual		100	100	100	110	100	120	130	140	150	160	170	180	190	200	210		
	Saving		0	0	0	-10	0	0	0	0	0	0	0	0	0	0	0		
	Incr sav		0	0	0	-10	0	-10	0	0	0	0	0	0	0	0	0		
	EBSS																		
	Carryover	1		0	0	0	0	0	-10	-10	-10	-10	-10	0	0	0	0		
		2			0	0	0	0	0	0	0	0	0	0	0	0	0		
		3				0	0	0	0	0	0	0	0	0	0	0	0		
		4					-10	-10	-10	-10	-10	0	0	0	0	0	0		
		5						0	0	0	0	0	0	0	0	0	0		
		Sum	0	0	0	0	0	-10	-10	-10	-10	0	-10	0	0	0	0		
	Total allowance		100	100	100	100	100	110	120	130	140	160	160	180	190	200	210		
	Actual		100	100	100	110	100	120	130	140	150	160	170	180	190	200	210		
	Gain/Loss		**0**	**0**	**0**	**-10**	**0**	**-10**	**-10**	**-10**	**-10**	**0**	**-10**	**0**	**0**	**0**	**0**		
	Benefit to TNSP		0	0	0	-10	0	-10	-10	-10	-10	0	-10	0	0	0	0	-49.340	-0.167
	Disc		1.191	1.1236	1.06	1	0.9434	0.89	0.8396	0.7921	0.7473	0.705	0.6651	0.6274	0.5919	0.5584	0.5268		

Source: Frontier Economics

Using the AER's existing opex forecasting methodology and the existing EBSS, this example shows the financial impact on a TNSP of bringing-forward opex from the year following the base year into the base year used to forecast opex for RCP2, while experiencing an increase in its opex RoC from $0 to $10 per annum.

Under these conditions, the TNSP faces a NPV loss of $49.34 discounted to year 4 of RCP1. This is $0.17 greater than under the base case described in Figure 7 (where there is no bringing-forward of opex). The present example shows that the TNSP incurs a NPV penalty of approximately 30% from artificially boosting its base year opex ($0.17 out of an overall NPV loss of $0.57).

Appendix B – Worked examples (assuming RoC1=0, RoC2=10 and 6% discount rate)

Figure 14: Bring-forward opex: Alternative opex forecasting methodology with penultimate year base year and existing EBSS

		RCP	1					2					3					NPV for TNSP	Change from BC
		Yr	1	2	3	4	5	1	2	3	4	5	1	2	3	4	5		
Alternative	Forecast		100	100	100	100	100	130	140	150	160	170	170	180	190	200	210		
Base Year = Penultimate year [4th year]	Actual		100	100	100	110	100	120	130	140	150	160	170	180	190	200	210		
	Saving		0	0	0	-10	0	10	10	10	10	10	0	0	0	0	0		
	Incr sav		0	0	0	-10	0	0	0	0	0	0	0	0	0	0	0		
	EBSS																		
	Carryover	1		0	0	0	0	0	0	0	0	0	0	0	0	0	0		
		2			0	0	0	0	0	0	0	0	0	0	0	0	0		
		3				0	0	0	0	0	0	0	0	0	0	0	0		
		4					-10	-10	-10	-10	-10	0	0	0	0	0	0		
		5						0	0	0	0	0	0	0	0	0	0		
		Sum	0	0	0	0	0	-10	-10	-10	-10	0	0	0	0	0	0		
	Total allowance		100	100	100	100	100	120	130	140	150	170	170	180	190	200	210		
	Actual		100	100	100	110	100	120	130	140	150	160	170	180	190	200	210		
	Gain/Loss		**0**	**0**	**0**	**-10**	**0**	**0**	**0**	**0**	**0**	**10**	**0**	**0**	**0**	**0**	**0**		
	Benefit to TNSP		0	0	0	-10	0	0	0	0	0	10	0	0	0	0	0	-2.950	-0.167
	Disc		1.191	1.1236	1.06	1	0.9434	0.89	0.8396	0.7921	0.7473	0.705	0.6651	0.6274	0.5919	0.5584	0.5268		

Source: Frontier Economics

Using the alternative opex forecasting methodology (with a penultimate base year) and the existing EBSS, this example shows the financial impact on a TNSP of bringing-forward opex from the year following the base year into the base year used to forecast opex for RCP2, while experiencing an increase in its opex RoC from $0 to $10 per annum.

Under these conditions, the TNSP faces a NPV loss of $2.95 discounted to year 4 of RCP1. This is $0.17 greater than under the base case described in Figure 8 (where there is no bringing-forward of opex). The present example shows that the TNSP incurs a NPV penalty of approximately 30% from artificially boosting its base year opex. This means that the use of the alternative opex forecasting methodology together with the existing EBSS does not create perverse incentives to bring-forward opex into the base year.

Appendix B – Worked examples (assuming RoC1=0, RoC2=10 and 6% discount rate)

Figure 15: Bring-forward opex: Alternative opex forecasting methodology with ante-penultimate year base year and existing EBSS

		RCP	1					2					3					NPV for TNSP	Change from BC
		Yr	1	2	3	4	5	1	2	3	4	5	1	2	3	4	5		
Alternative	Forecast		100	100	100	100	100	140	150	160	170	180	180	190	200	210	220		
Base Year = Ante-penultimate year [3rd year]	Actual		100	100	110	100	120	130	140	150	160	170	180	190	200	210	220		
	Saving		0	0	-10	0	-20	10	10	10	10	10	0	0	0	0	0		
	Incr sav		0	0	-10	10	-10	20	0	0	0	0	0	0	0	0	0		
	EBSS																		
	Carryover	1		0	0	0	0	0	20	20	20	20	20	0	0	0	0		
		2			0	0	0	0	0	0	0	0	0	0	0	0	0		
		3				-10	-10	-10	-10	-10	0	0	0	0	0	0	0		
		4					10	10	10	10	10	0	0	0	0	0	0		
		5						-10	-10	-10	-10	-10	0	0	0	0	0		
		Sum	0	0	0	0	0	-10	-10	-10	0	-10	20	0	0	0	0		
	Total allowance		100	100	100	100	100	130	140	150	170	170	200	190	200	210	220		
	Actual		100	100	110	100	120	130	140	150	160	170	180	190	200	210	220		
	Gain/Loss		**0**	**0**	**-10**	**0**	**-20**	**0**	**0**	**0**	**10**	**0**	**20**	**0**	**0**	**0**	**0**		
	Benefit to TNSP		0	0	-10	0	-20	0	0	0	10	0	20	0	0	0	0	-8.202	-0.167
	Disc		1.1236	1.06	1	0.9434	0.89	0.8396	0.7921	0.7473	0.705	0.6651	0.6274	0.5919	0.5584	0.5268	0.497		

Source: Frontier Economics

Using the alternative opex forecasting methodology (with an ante-penultimate base year) and the existing EBSS, this example shows the financial impact on a TNSP of bringing-forward opex from the year following the base year into the base year used to forecast opex for RCP2, while experiencing an increase in its opex RoC from $0 to $10 per annum.

Under these conditions, the TNSP faces a NPV loss of $8.20 discounted to year 4 of RCP1. This is $0.17 greater than under the base case described in Figure 9 (where there is no bringing-forward of opex). The present example shows that the TNSP incurs a NPV penalty of approximately 30% from artificially boosting its base year opex. This means that the use of the alternative opex forecasting methodology together with the existing EBSS does not create perverse incentives to bring-forward opex into the base year.

Appendix B – Worked examples (assuming RoC1=0, RoC2=10 and 6% discount rate)

Appendix C – CV for Rajat Sood

NAME:	RAJAT SOOD
Profession:	Economist

Rajat is a founding member of Frontier Economics and is a qualified solicitor, as well as a trained economist. Rajat has a broad range of experience in advising state and national governments, regulatory bodies and businesses on issues arising in access regulation, market design, cost-benefit analysis and competition evaluation, especially in relation to the energy sector. In recent years, Rajat has been a key advisor to institutions such as the Australian Energy Market Commission (AEMC), the Australian Energy Regulator (AER), the New Zealand Electricity Commission, the New Zealand Commerce Commission and the Singapore Energy Market Authority.

Prior to working as an economist, Rajat was a solicitor at the law firm Freehill Hollingdale & Page in Melbourne where he worked on commercial and trade practices issues in a range of areas, including being part of the team advising the Commonwealth Government on the sale of the first tranche of Telstra shares.

Clients benefit from Rajat's advice, through his:

- Clear framework for applying economics to real-world problems
- Deep understanding of utility economics and regulation
- Detailed knowledge of the National Electricity Market and overseas electricity markets
- Strong ability to communicate difficult concepts clearly and precisely.

KEY EXPERIENCE

Energy network regulation

Electricity network regulation

- ***Ergon Energy network pricing:*** Rajat has been advising Ergon Energy on network pricing issues for three years. He initially advised Ergon on the development of appropriate network pricing principles and the transition of its existing tariffs to a new structure that is more consistent with those principles. His role subsequently included the preparation of a Tariff Implementation Report for Ergon and assistance in drafting Ergon's Tariff Structure Statement (TSS), which Ergon is required to submit to the AER under the Rules. He is currently assisting Ergon respond to stakeholder comments on its TSS and is helping design a new cost allocation methodology (2013- ongoing).

- ***Prudent discount:*** Rajat advised AEMO on its review of an application from a transmission customer for a prudent discount on the customer's transmission charges (2015-16).
- ***Value of embedded generation:*** Rajat was part of the Frontier Economics team engaged by the Energy Networks Association (ENA) to undertake a detailed qualitative and quantitative analysis of the value of embedded generation in response to a proposed amendment to the National Electricity Rules (NER). The proposed amendment was to include a requirement for network businesses to offer a network credit to eligible Embedded Generation (EG) for electricity exported to the network. The analysis and report demonstrated that the interaction of any generally available network credit with the existing regulatory, policy and market settings could lead to unintended consequences, including incentivising inefficient investment in, and use of, EG in locations, quantities or technologies where it may create net costs to networks and potentially lead to higher electricity prices for consumers. The report was submitted to the AEMC (2015).
- ***Singapore Power connection charge:*** Rajat advised Singapore Power (SP) and a Singaporean generator on the appropriate charge payable by SP to the generator in return for the generator agreeing to allow SP to install a transformer at the generator's switchyard. Our advice drew from Nash bargaining theory to devise a charge that shared the benefits of the transformer between the generator and SP's customers. The Singapore Energy Market Authority was consulted throughout the analysis and approved our recommended connection charge (2015).
- ***TransGrid long-term lease:*** Rajat was part of the Frontier team advising one of the consortia bidding for New South Wales electricity transmission business, TransGrid. Rajat's role included explaining the operation and application of the AER's expenditure incentive schemes to TransGrid. These schemes are the:
  - Efficiency-Benefit Sharing Scheme (EBSS) for operating expenditure and
  - Capital Expenditure Sharing Scheme (CESS) for capital expenditure (2015).
- ***Transpower IRIS:*** Rajat prepared a report for Transpower New Zealand examining the implications of the Commerce Commission's intended changes to Transpower's Incremental Rolling Incentive Scheme (IRIS). The Commission was planning to implement a 'symmetric' IRIS, which would penalise aggregate over-spending by Transpower during a regulatory period at the same rate as it would reward aggregate under-spending. While this would be appropriate under a conventional 'base year' approach to forecasting

operating expenditure, our report noted that in light of the Commission's 'bottom-up' approach to forecasting Transpower's allowed operating expenditure, application of a symmetric IRIS could lead to perverse incentives for Transpower to engage in inefficient behaviour. Our report suggested that Transpower's current IRIS mechanism (or no IRIS mechanism at all) would be preferable to the Commission's proposed IRIS under these circumstances (2015).

- ***Major Operating Projects:*** Rajat advised TransGrid on the appropriate regulatory treatment of TransGrid Major Operating Projects (MOPs). In particular, he prepared a report discussing whether the AER had correctly applied to TransGrid the framework he developed when advising the AER on a different business's regulatory proposal (2014-15).
- ***Replacement project evaluation template:*** Rajat advised electricity distributor, Jemena, on the appropriate methodology to undertake a cost-benefit analysis of its replacement network projects. This included overseeing the development of a sophisticated spreadsheet template to enable Jemena to conduct a cost-benefit analysis of alternative network replacement projects. The template allows users to test and compare the potential public benefits from different network and non-network options. The template builds on the framework adopted by the AER in its Regulatory Investment Test for Distribution and is designed to assist the business justify its proposed replacement capital expenditure to the regulator (2014).
- ***Network planning arrangements in Western Australia:*** Rajat led the drafting of a report for the Public Utilities Office (PUO) of Western Australia to inform the state government's Electricity Market Review. The report assessed the benefits and costs of existing transmission planning and connection arrangements in Western Australia and commented on the appropriateness of changes to these arrangements. The report also discussed the implications of alternative transmission planning and connection arrangements for the operation of the Western Australian wholesale electricity market. The report was used by the PUO to prepare a detailed set of reforms and implementation arrangements, which were provided to the Minister for Energy (2015).
- ***Metering competition:*** Rajat advised the AEMC on the implications of opening up of metering activities to competition for the competitiveness of retail electricity supply and the supply of energy services. As part of this work, Rajat presented to the AEMC Commissioners and spoke at an AEMC Public Forum (2014).
- ***Transpower WACC:*** Rajat was part of the Frontier team supporting Transpower through a review by the Commerce Commission on the approach to estimating the cost of capital. This included preparing a number of reports

setting out the conceptual, empirical and regulatory evidence for choosing a WACC value above the midpoint of the estimated WACC range (2014).

- ***Meralco Performance-Based Regulation:*** Rajat was part of the Frontier team that provided advice to Meralco, the largest electricity distribution network in the Philippines, on aspects of the review of the operation of performance-based regulation (PBR) being conduction by the Electricity Regulatory Commission of the Philippines. Our advice covered the successes of the existing PBR regime, reasonable expectations for the forthcoming period, and the advantages and disadvantages of changes to various parameters used to set prices (such as asset valuation and depreciation methodology) (2014).
- ***New Zealand Default Price-Quality Path distribution reset:*** Rajat was part of the Frontier team advising the Electricity Networks Association of New Zealand on:
  - the formulation and testing of econometric models that identify and quantify the drivers of network capital and operating expenditure for the Electricity Distribution Businesses" (EDBs') default price-quality path (DPP) resets; and
  - potential approaches for making use of EDBs' Asset Management Plan forecasts in their DPP resets. This included the scope for adopting innovative 'menu regulation' in New Zealand (2013-2014).
- ***SP AusNet controllable opex:*** Rajat advised the AER on the appropriateness of the application of a single base year approach to forecasting SP AusNet's total controllable operating expenditure, including SP AusNet's 'asset works' opex (2013-2014).
- ***AEMO VCR Issues Paper:*** Rajat helped prepare an issues paper on the Value of Customer Reliability (VCR) for AEMO. The issues paper highlighted the key roles and potential applications of a VCR in the Australian National Electricity Market and discussed the strengths and weaknesses of the various methodologies that had been used for estimating VCR in Australia and internationally (2013)
- ***Jemena distribution pricing Rule change:*** Rajat prepared a report for Jemena Electricity Networks discussing the pros and cons of alternative means of recovering distribution network businesses' sunk costs not recovered through charges reflecting long run marginal cost. His report compared and contrasted Ramsey pricing and postage stamp pricing as well as equity-based pricing approaches (2013).
- ***AER Expenditure Incentives Guidelines:*** Rajat advised the AER on the development of network expenditure incentive guidelines as part of the AER's 'Better Regulation' work program (2013).

- ***AER cost of capital:*** Rajat helped advise the AER on the nature and extent of risks to which Australian energy networks are exposed. This work fed into the AER's work on defining the "benchmark efficient entity", an important part of its regulatory framework and element of its 2013 Rate of Return Guidelines as part of the AER's 'Better Regulation' work program (2013).
- ***AER RIT-D:*** Rajat advised the AER on the development of the Regulatory Investment Test for Distribution (RIT-D) and the RIT-D Application Guidelines. The RIT-D is an economic cost-benefit test for assessing distribution network augmentations, which requires augmentation options to be compared against DG and demand-side response options (2013).
- ***New Zealand Transmission Pricing Methodology:*** Rajat prepared a report for Mighty River Power reviewing the New Zealand Electricity Authority's proposed Transmission Pricing Methodology. The Authority proposed introducing two new transmission charges – a 'beneficiaries-pay charge' and a 'residual charge' (2012-13).
- ***Power of Choice Review:*** Rajat provided advice to the AEMC in relation to a number of matters including:
  - barriers to more cost-reflective retail pricing in the NEM as a means of encouraging more demand-side response from end-use customers. His role included presenting Frontier's findings to the AEMC's Third Stakeholder Reference Group Meeting in May 2012
  - amending the distribution pricing principles in the National Electricity Rules to provide better guidance for businesses to develop efficient and flexible tariff structures that support demand-side participation (2012).
- ***Smart meter rollout:*** Rajat advised the Victorian Department of Treasury and Finance on the regulatory consequences of halting, suspending or modifying the rollout of smart meters in Victoria. His advice covered issues such as the potential avenues for changing the rollout, cost recovery implications, timing implications and the need to maintain good regulatory practice (2012).
- ***Connection Initiatives project:*** Rajat assisted AEMO on the development of policies for (i) the management of multiple connection applications and (ii) cost-sharing arrangements at terminal station hubs. His advice helped the AEMO to develop connection arrangements that promote economic efficiency, especially in an environment of increasing connection applications, particularly from wind farms. In doing so, he helped AEMO to meet its statutory objectives (2011).
- ***Basslink conversion:*** Rajat was part of the Frontier team investigating the benefits and costs of converting the Basslink market network service into a prescribed service, on behalf of Hydro Tasmania. This work included calculating the market benefits of Basslink and determining the potential value

of the regulated asset base that would apply to Basslink should it be converted. Rajat also advised Hydro Tasmania on the potential Rule changes that may be required to preserve the System Protection Scheme, which helps to maintain the non-firm transfer capacity of Basslink (2011).

- ***United Energy Distribution operating expenditure:*** As part of the Victorian electricity distribution determination process, the AER examined United Energy Distribution's (UED's) operating expenditure forecasts. UED was implementing a new business model in which it outsourced fewer services and undertook more activities in-house in order to improve the quality and flexibility of its service performance. Frontier was asked to advise Johnson Winter & Slattery about the meaning and interpretation of clause 6.5.6(c) of the National Electricity Rules in relation to how it applied to UED's proposed operational expenditures under its new business model. The AER quoted approvingly from Frontier's report in its Final Determination (2010).
- ***Transmission Frameworks Review:*** Rajat provided preliminary advice to the Northern Generators in relation to formulating their submission to the AEMC's Transmission Frameworks Review Issues Paper (2010).
- ***AER RIT-T drafting:*** Rajat advised the AER on the appropriate drafting of the proposed Regulatory Investment Test for Transmission (RIT-T), which replaced the Regulatory Test, and the accompanying RIT-T Application Guidelines (2009 – 2010).
- ***Climate Change impacts on transmission:*** Rajat assisted a group of NEM participants on the appropriate response to the AEMC's recommended changes to transmission pricing and congestion management in light of climate change policies (2009 – 2010).
- ***NERGs advice:*** Rajat advised the AER on the economic efficiency and regulatory implications of the AEMC's proposed options for a new regulatory regime for dealing with new generator-serving transmission network extensions (NERGs) (2009).
- ***Victorian AMI audit:*** Rajat advised the Victorian Auditor-General's Office (VAGO) on VAGO's performance audit of the Victorian Government's decision to mandatorily roll-out smart meters across Victoria from 2009. Frontier's analysis fed into VAGO's report, which was tabled in the Victorian parliament in November 2009 (2009).
- ***NZ Transmission pricing:*** Rajat prepared a report for the New Zealand Electricity Commission (now the Electricity Authority) on the economics of transmission pricing, international experience and potential 'high-level' options for consideration as part of the Commission's Transmission Pricing Review. Our report is available on the Electricity Authority website (2009).

- ***Prescribed and negotiated transmission services:*** Rajat advised VENCorp on the interpretation and application of those aspects of the National Electricity Rules that deal with the delineation between regulated (or 'prescribed') and unregulated (or 'negotiated') transmission services (2009).
- ***Multi-sector utilities:*** Rajat was primary author of a report for the New Zealand Commerce Commission on international approaches to the regulation of multi-sector utilities (2008).
- ***Inter-regional transmission charging:*** Rajat drafted a report for the AEMC advising on the pros and cons of different approaches to inter-regional transmission charging in the NEM (2008).
- ***EnergyAustralia Rule Change:*** Rajat assisted the AEMC with the analysis of a proposed Rule change from EnergyAustralia concerning the appropriate regulatory treatment of EnergyAustralia's transmission assets. This included preparing a draft of the AEMC's Draft Decision and the Rule change itself (2008).
- ***Regulatory Test amalgamation:*** Rajat advised the AEMC on the merits of various options for amalgamating the "reliability" and "market benefit" criteria of the Regulatory Test, pursuant to a direction from the Ministerial Council on Energy (MCE). Also advised on aspects of the new "RIT-T" to replace the Regulatory Test (2007-08).
- ***Regulatory Test Guidelines***: On behalf of the AER, Rajat developed guidelines for the application of the Regulatory Test by network service providers, as required by a Rule change instituted by the AEMC. Also advised the AER on appropriate revisions to the Regulatory Test following the Rule change (2007).
- ***Real options:*** Frontier and SFG Consulting is advising the Victorian transmission planner, VENCorp, on how a real options analysis can be used to guide investment decisions in easements in advance of developing network augmentations (2007).
- ***Transmission pricing:*** Rajat advised the AEMC on its review of transmission pricing in the NEM. This included the preparation of a scoping paper for the review, Working Papers explaining various technical topics, an Issues Paper for stakeholder consultation and leading the development of the Commission's Rule Change Proposal, Draft Determination and Final Determination (2006).
- ***Revenue Rule Proposal:*** Rajat advised the AEMC on a range of matters relating to the AEMC's Rule Change proposal on the regulation of transmission revenues in the NEM. Specifically, this included advice on the appropriate treatment for network asset depreciation, large 'contingent projects' and transmission incentives (2005-06).

- ***ACCC metering:*** Analysis of the costs and benefits of maintaining a distributor monopoly over small customer electricity metering services for the ACCC (2004).
- ***NZ Grid Investment Test:*** Development of a draft "Grid Investment Test" (GIT) for the New Zealand Electricity Commission. The GIT is a cost-benefit test for transmission investment and will be applied to significant economic and reliability transmission investments by Transpower. Frontier made recommendations on the types of costs and benefits to be included in the GIT assessment, such as generation cost savings, reliability benefits and environmental benefits and taxes – available here (2004).
- ***NZ Transmission pricing methodology:*** Development of a transmission pricing methodology on behalf of the New Zealand Electricity Commission to apply to the recovery of existing and new investment costs by Transpower – available here. The Board of the Commission used Frontier's work as a basis for consultation with stakeholders on an appropriate pricing methodology (2004).
- ***Regulatory Test competition benefits:*** Theoretical and empirical report for the ACCC on amendments to the Regulatory Test for transmission augmentations to allow for the inclusion of competition benefits in the assessment of transmission investments. Frontier modelled competition benefits from an actual transmission investment in the National Electricity Market (NEM). Frontier's report is on the AER website here (2003).
- ***Transmission policy paper:*** On behalf of the NSW jurisdiction, drafted a policy discussion paper for the NEM Ministers' Forum on the role and governance of networks in the NEM examining the economic characteristics of networks and governance models for network service provider incentives (2002).
- ***SNI appeal:*** Key member of the NSW Minister for Energy's team on the South Australia- New South Wales Interconnector appeal, addressing issues such as:
  - the interpretation and application of the ACCC's Regulatory Test and
  - network governance and revenue regulation, including treatment of capital expenditures and asset optimisation (2001-02).

Gas network regulation

- ***Transmission depreciation methodology:*** Rajat advised the Australian Energy Regulator on the implications of APA GasNet's proposed approach to depreciation of their Victorian gas transmission assets as part of APA GasNet's 2013-17 access arrangement. In particular, Rajat advised the AER on whether APA GasNet's proposed approach was likely to lead to reference tariffs that would vary, over time, in a way that promotes efficient growth in the market for reference services. APA GasNet appealed the AER's decision and the Australian Competition Tribunal upheld the AER's decision (2012-13).

- ***Services contract buyout:*** Rajat advised the Australian Energy Regulator on the appropriate regulatory treatment of the costs incurred by APT Petroleum Pipelines Ltd in the buyout of a contract for services from Agility. Our advice was cited by the AER in its Final Decision (2012).
- ***Multinet forecasting efficient operating expenditure:*** Rajat helped prepare a report for Multinet Gas in Victoria challenging the AER's approach to forecasting the distributor's level of efficient operational expenditure in the 2013-17 arrangement period. Our report was submitted as part of the distributor's response to the AER's Draft Decision (2012).
- ***WA gas access arrangement revisions:*** Rajat provided economic advice to the Western Australian Economic Regulation Authority on revisions to the Access Arrangements of the Goldfields Gas Pipeline and the Mid-West and South-West Gas Distribution Systems (2009-2011).
- ***VENCorp real options application:*** With SFG Consulting, Rajat advised VENCorp on the application of a real options analysis framework to the acquisition of easements for potential future gas pipelines (2007-2009).

Wholesale electricity market design and reform implementation

- ***Market power mitigation mechanisms:*** Rajat is part of the Frontier Economics team currently advising the Singapore Energy Market Authority on its review of the vesting contract regime and alternative mechanisms for managing market power in the Singapore wholesale electricity market (2015-ongoing).
- ***Participant fees:*** Rajat prepared a report for Queensland generator, CS Energy, in response to AEMO's proposed approach to (i) allocating AEMO's operating budget between participant classes and (ii) setting its fee structure. Our report applied the principles in the National Electricity Rules to develop a more robust and economically efficient cost allocation and fee structure. Our report was attached to CS Energy's submission to AEMO's consultation process (2016).
- ***Response to rebidding Rule change:*** Rajat prepared a report for CS Energy, responding to the AEMC's second draft Rule determination on the rebidding Rule change. Our report critiqued the AEMC's analysis, including its estimates of 'economic harm' from 'deliberate late rebidding' by generators. Our report also highlighted a range of flaws with the AEMC's proposed Rule change. The report was submitted by CS Energy to the AEMC as part of the consultation process on the second draft Rule determination (2015).

- ***Barriers to exit:*** Rajat contributed to a report for the AEMC on generator barriers to exit. The report discussed what factors could drive generators of different technologies to partly or fully exit the NEM (2015).
- ***Financial Market Resilience:*** Rajat prepared a report for the AEMC assessing potential options for preserving the financial resilience of the NEM in the event of a large retailer failure. His analysis included examining different scenarios of large retailer failure to project the implications for AEMO and distribution network credit support. He also put forward a new option of delayed settlement for addressing financial contagion risks. Frontier's report was used by the AEMC to assist in the preparation of its second interim draft report. Rajat provided further assistance to the AEMC with modelling and analysis feeding into its final report (2014-15).
- ***Optional Firm Access:*** Rajat was involved in preparing a series of reports for a group of NEM participants on the issues raised by the AEMC's Optional Firm Access (OFA) proposal, as described in the AEMC's First Interim report on OFA design and testing. Rajat's role focussed on examining the qualitative arguments in favour of OFA, in particular the robustness of the purported generation-transmission investment coordination benefits. Rajat also examined some of the access pricing results tabled in the First Interim Report (2014-15).
- ***Capacity mechanisms:*** Rajat prepared a report for the AEMC on the role of electricity market design in facilitating efficient generator entry and exit in the NEM and other electricity markets (2014).
- ***New Zealand single buyer model:*** Rajat drafted a report for Meridian Energy on the opposition Labour and Greens parties' proposal to abolish the New Zealand wholesale electricity market and replace it with a single buyer known as 'NZ Power' (2013).
- ***CarbonNet Project:*** Rajat advised the Victorian Department of Primary Industries on the implications of the proposed CarbonNet carbon capture & storage project on participant incentives and price outcomes for the Australian National Electricity Market (2012-13).
- ***Transmission Frameworks Review – Optional Firm Access:*** Rajat advised the National Generators' Forum on the economic impacts of the proposal for Optional Firm Access contained in the AEMC's Second Interim Report for its Transmission Frameworks Review. Rajat's response was attached to the NGF's submission and he subsequently met with the AEMC to explain the points highlighted in the report (2012).
- ***Transmission Framework Review options critique:*** Rajat prepared a paper that formed the basis of a submission from the National Generators' Group to the AEMC's First Interim Report for its Transmission Frameworks Review. Rajat's response highlighted the shortcomings of the AEMC's proposed five options for congestion management (2012).

- ***Tasmanian electricity reform:*** Rajat was part of the Frontier team advising the Tasmanian Electricity Supply Industry Expert Panel (the Panel) on its investigation into the current position and future development of Tasmania's electricity industry. There were two key aspects to Frontier's advice:
  - An assessment of the effectiveness of the wholesale electricity sector. Frontier examined historic outcomes in the wholesale sector, and undertook market modelling, to assess the extent of market power in the Tasmanian wholesale electricity sector. Frontier found that there was no evidence of sustained market power being exercised in the wholesale sector even though there is significant potential for sustained market power to be exercised.
  - Advice on structural, regulatory and governance options to reform Tasmania's electricity industry, and analysis of anticipated changes in the performance of the market. Among other things, Frontier found that disaggregating bidding control of generation assets in Tasmania would diminish the potential for sustained market power to be exercised

  Rajat’s role included assistance in drafting the Panel’s report to the Tasmanian Government (2011-12).
- ***Generator market power:*** Rajat drafted a report for the National Generators Group responding to questions and issues raised in the AEMC’s Consultation Paper on generator market power in the National Electricity Market (2011).
- ***Increasing the MPC and CPT:*** Rajat was the primary author of a report for the AEMC discussing the non-reliability implications of increasing the Market Price Cap and Cumulative Price Threshold in the NEM. This included the implications for generator investment, wholesale prices, financial contracting, incentives to exercise market power, demand-side response and prudential requirements – available here (2010).
- ***Victorian system force majeure dispute:*** Rajat advised TRUenergy on the economic interpretation of the system force majeure provisions in the Victorian Gas Market and System Operation Rules in relation to a dispute with VENCorp before the gas industry Dispute Resolution Panel. This advice included quantification of the impact of a gas interruption on the Victorian gas market. Rajat also acted as an expert witness for TRUenergy before the Panel. The Panel decided in favour of VENCorp. (2009)
- ***WA Wholesale Market Review:*** Rajat advised the Economic Regulation Authority on the preparation of their second and third reports to the Minister on the effectiveness of the Wholesale Electricity Market in Western Australia. (2008 – 2009).

- ***AEMC generator nodal pricing:*** Rajat drafted a paper reviewing the theory and practice of generator nodal pricing for the AEMC as part of the Congestion Management Review (2008).
- ***AEMC Congestion Management Review:*** Rajat was an advisor to the AEMC on approaches to congestion management in the NEM pursuant to a review reference from the MCE. Rajat's role included coordinating Frontier's market and risk modelling contributions to the CMR and assisting with the drafting of various AEMC publications. Rajat was involved in all stages and facets of the CMR, including:
  - Understanding the nature of the physical and financial trading risks created by congestion;
  - Describing existing arrangements in the NEM for managing the trading risks created by congestion;
  - Estimating and assessing the materiality of congestion in the NEM, including by undertaking relevant market modelling of the economic cost of congestion in dispatch;
  - Proposing and assessing options for improvements to the congestion management regime in light of the materiality of the problem; and
  - Assistance with drafting the AEMC's CMR publications (2006-08).
- ***Snowy region boundary change proposals:*** Rajat advised the AEMC on the three proposals put forward by participations for redrawing the Snowy regional boundaries in the NEM. Rajat coordinated Frontier's modelling for the assessment of all three proposals, drafted the AEMC's modelling appendix and provided drafting assistance for the AEMC's draft and final determinations (2007).
- ***Singapore EMA and EDB embedded generation:*** Prepared a report jointly for the Singapore Energy Market Authority (EMA) and the Economic Development Board (EDB) with the assistance of engineers SKM, assessing the efficiency of the existing regulatory arrangements for embedded generation in the Singapore National Electricity Market and recommending potential improvements (2005-06).
- ***Victorian coal royalty increase:*** Preparation of a paper for Loy Yang Marketing Management Company discussing the likely ability of Victorian brown coal generators to 'pass through' an increase in the coal royalty to customers via spot or wholesale prices (2005).
- ***Victorian energy cross-ownership laws:*** Developing a submission on the review of Victorian energy cross ownership laws for the Energy Users Association of Australia (2005).

- ***Reliability Panel guidelines for NEMMCO intervention:*** Drafted a report for the AEMC assessing and refining the Reliability Panel's proposed guidelines for NEMMCO's reserve contracting powers (2005).
- ***Remuneration for system restart services:*** Development of a submission for Macquarie Generation on the appropriate remuneration for system restart services in the NEM (2005).
- ***Singapore EMA embedded generation:*** Drafted a report for the Singapore EMA on the appropriate regulatory treatment of *existing* embedded generators in the Singapore National Electricity Market. The recommendations of the report were implemented by the EMA (2005).
- ***'Snowy' trial of CSP/CSC arrangements:*** Contributor to a submission from Macquarie Generation to the ACCC on the merits of introducing constraint support pricing (CSP) and constraint support contracts (CSC) arrangements within the Snowy region of the NEM (2004).
- ***NETA****:* Paper for the Japanese Central Research Institute of the Electric Power Industry (CRIEPI) describing the origin and workings of the England and Wales New Electricity Trading Arrangements. The paper also examined recent regulatory developments and price outcomes, as well as recent transactions in the UK power sector (2003).
- ***NSW MIG and MEU:*** Rajat was a key member of the Frontier team advising the New South Wales Market Implementation Group and Ministry of Energy and Utilities of a range of electricity market, regulation and governance issues (1999-2003).
- ***Market fees****:* Co-authored a report to the National Retailers Forum on the appropriate structure of market fees in the NEM (1998).
- ***Queensland electricity reform****:* Part of the team advising the Queensland Electricity Reform Unit in relation to issues arising in the Queensland Interim Market (1998).

Greenhouse policy analysis

- ***Generator Impacts of Climate Change Policies:*** Rajat was the primary author of a report for the AEMC assessing the impacts of the CPRS and the enhanced RET on generator bidding, contracting and investment decisions in the NEM for the AEMC (2008).
- ***Western Australian and Northern Territory impacts of climate change policies:*** Rajat drafted a report for the AEMC on the potential implications of the CPRS and RET for the Western Australian and Northern Territory energy markets (2008).

- ***ETS auction design:*** Rajat advised the National Generators Forum (NGF) on the Federal Government Green Paper's proposed CPRS auction design, with Frontier's report forming an attachment to the NGF's submission (2008).

Retail electricity market reform and implementation

- ***AEMC Review of NEM Financial Resilience:*** Rajat advised the AEMC on the assessment of potential options for limiting the risk of 'financial contagion' in the NEM as a result of the failure of a large electricity retailer. Rajat's analysis builds on and extends the AEMC's work in its First Interim Report for the Financial Resilience Review (2014).
- ***Distributor credit support:*** Rajat was part of the Frontier team that undertook, on behalf of AGL, Origin Energy and Energy Australia, a critical review of the current distribution network service provider (DNSP) credit support scheme operating in the NEM, and provided recommendations on possible improvements. Australia's National Electricity Rules make provision for electricity retailers to provide credit support to DNSPs to cover losses in the event that retailers default. In 2012 the credit support arrangements were revised in such a way that a greater burden fell on the largest retailers, who also tend to be the least risky businesses. Rajat examined the efficiency consequences of this change and proposed amendments to the scheme aimed at improving the efficiency outcomes of the arrangements (2013-14).
- ***ERAA costs of interval metering:*** Critical review of retailers' costs of accommodating interval meter roll out across Australian and international jurisdictions. This has included a wide-ranging literature review of interval meter analyses across NEM and international jurisdictions, as well as a critique of cost-benefit studies that have been undertaken to date (2006-07).
- ***Ofgem:*** Part of a team working for the England and Wales gas and electricity markets regulator examining certain developments in the retail electricity market (2003).
- ***Full retail competition in NSW:*** Key member of the team implementing FRC in electricity in New South Wales and undertaking a range of assignments, including:
  - Development of the small customer protection framework – including the original Marketing Code of Conduct and default customer connection contracts
  - Default rules for interaction between retailers and monopoly distribution network businesses
  - Default rules for metering

- Drafting submissions to the ACCC supporting a National Electricity Code derogation to allow customers to switch retailer without needing to install an interval meter
- Retailer of last resort provisions (2000-2003).

Competition analysis

- ***AGL proposed acquisition of Macquarie Generation:*** Rajat was part of the Frontier Economics team advising AGL's lawyers, Ashurst, on competition issues raised in the proposed acquisition of Macquarie Generation. AGL were successful in the Australian Competition Tribunal (2014).
- ***ACCC vertical integration:*** Rajat drafted a paper for the ACCC on the competition and efficiency implications of vertical mergers in electricity, with specific reference to the acquisition of TXU Australia (a retailer, distributor and generator in the NEM) by Singapore Power (the owners of Victoria's transmission network) (2004).

CAREER

1999 to present	Consultant, Frontier Economics
1998 to 1999	Consultant, London Economics
1997 to 1998	Articled clerk, then solicitor, Freehills, Hollingdale & Page

EDUCATION

1990 – 1995	LLB (honours), University of Melbourne
1990 – 1993	B.Com (first class honours), University of Melbourne

Rajat maintains an Australian legal practising certificate and is a Barrister and Solicitor of the Supreme Court of Victoria.

PUBLICATIONS

"Evolution of Australia's National Electricity Market", Chapter 19 in *Evolution of Global Electricity Markets, New paradigms, new challenges, new approaches*, Edited by Fereidoon P. Sioshansi (2013) Elsevior Inc., with Alan Moran

"Decentralized Generation in Australia's National Electricity Market? No Problem, Chapter 19 in *Distributed Generation and Its Implications for the Utility Industry*, Edited by Fereidoon P. Sioshansi (2014) Elsevior Inc., with Liam Blanckenberg.

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