The Brattle Group

Framework for assessing capex and opex forecasts as part of a "building blocks" approach to revenue/price determinations

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1. SUMMARY AND CONCLUSIONS

1.1 INTRODUCTION AND APPROACH

1. The Australian Energy Regulator (AER) recently proposed a change to the National Electricity Rules (the Rules) that address capital expenditure (capex) and operating expenditure (opex) allowances, and how forecasts submitted by a network business are to be examined by the AER in making an electricity distribution or transmission determination. In connection with this rule change request, the Australian Energy Market Commission (AEMC) asked us to review regulatory practice addressing this topic in a range of regulatory jurisdictions, and to make comparisons with the practice of the AER. The objectives of our study are to describe the relevant rules and practices in each jurisdiction, to determine on the basis of this experience across jurisdictions whether the policy intent behind Chapter 6A of the Rules remains consistent with good practice, and to recommend possible improvements.

2. The AEMC asked us to review the regulatory schemes in Great Britain, New Zealand, New South Wales and Western Australia, and also to recommend two relevant jurisdictions in North America (we reviewed Ontario and Rhode Island).

3. The AEMC's policy intent in relation to the assessment of capex/opex forecasts was set out in its draft and final determinations on Chapter 6A of the Rules (which deals with transmission). We have reviewed these documents, as well as commentary from the AER[1] and the AEMC[2] in connection with the AER's current rule change proposal on capex/opex allowances. We also reviewed the Ministerial Council on Energy determinations on Chapter 6 of the Rules (which deals with distribution).

4. The AER has suggested that the current Rules tend to result in an upwards bias to the network service provider's (NSP's) forecasts, and that the current Rules limit the AER's ability to reject biased forecasts. In particular, the AER has expressed a view that its

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1 *Economic regulation of transmission and distribution network service providers – AER's proposed changes to the National Electricity Rules*, AER (September 2011); *Response to AEMC consultation paper - Economic Regulation of Network Service Providers*, AER (December 2011); and *Submission – AEMC Directions Paper – Economic regulation of Network Service Providers*, AER (April 2012).

2 *Directions Paper National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012 National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, AEMC (March 2012).

discretion[3] is limited by the requirements that its decision be "based on the NSP's proposal" and "adjusted only to the extent necessary".

1.2 THE AEMC'S "POLICY INTENT"

5. The question of regulatory discretion, and the need to balance the interests of customers and the NSPs, was considered by the AEMC in determining Chapter 6A of the Rules.

6. It is not clear to us what the AEMC's policy intent was in relation to whether the AER's decision should be "based on the proposal" or "adjusted only to the extent necessary", because this was not explicitly discussed in the AEMC's determination. While this language appears more prominently in Chapter 6 of the Rules than in Chapter 6A, we note that the AER has explained that the two chapters effectively constrain it in the same way.[4]

7. In our view, the current debate suggests that there is ambiguity over whether Chapter 6 of the Rules imposes more restrictions on the exercise of the AER's discretion than does Chapter 6A, and over whether the AEMC's Chapter 6A policy intent was for the AER's decision to be "based on the proposal" or "adjusted only to the extent necessary". It is also not clear to us whether the differences in drafting between Chapters 6 and 6A reflect differences in the nature of the transmission and distribution sectors.

8. We discuss below whether these restrictions appear to operate in the other jurisdictions we have examined, and whether they are likely to be helpful guides to the exercise of regulatory discretion.

9. In our view, the AEMC's policy intent was to limit, to some extent, the AER's discretion. The AEMC explained that "the exercise of [the AER's] judgement is constrained and guided… …the AER is not at large in being able to reject the TNSPs forecast and replace it with its own".[5] The AER must accept a forecast "if it is satisfied that the amount 'reasonably reflects' efficient and prudent costs" and reject it otherwise.[6]

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3 In the policy debate the terms "regulatory discretion" and "regulatory judgment" are used. In this report we use the terms interchangeably.

4 See AER's December 2011 submission.

5 See *National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18*, AEMC (November 2006), p. 53.

6 *Ibid.*, p. 52.

However, the AEMC also intended that the AER's ability to reject a forecast that does not reasonably reflect efficient and prudent costs should encourage the TNSP not to submit exaggerated forecasts: "…reduce the incentive for TNSPs to submit forecasts which represent ambit claims… …run the risk of being rejected and replaced by the AER".[7] The AEMC said that it was not possible to identify a "best estimate" figure for capex/opex forecasts, but it also rejected the concept of defining a reasonable range in which estimates would be acceptable if that would lead to upwards bias.[8]

1.3 FEATURES OF THE JURISDICTIONS WE REVIEWED

10. In the table overleaf, we have summarized some of the relevant features of the approach to assessing capex/opex forecasts in the jurisdictions we reviewed.

7 *Ibid.*, p. 53.

8 *Ibid.*, p. 52.

Table 1: Characteristics of the approach to assessing capex/opex forecasts in various jurisdictions

Jurisdiction	Australia (AER)	New Zealand	NSW (IPART)	WA (ERA)	Ontario (OEB)	Rhode Island (RIPUC)	Great Britain (Ofgem)
Prescription in the legal framework for determining capex/opex allowances?	Yes: National Electricity Rules address assessment of capex/opex allowances at some length	Little: Input Methodologies address various elements of the determination process, but little detail on capex/opex allowances	Some: National Electricity Code addressed capex/opex forecasts (no guidance for water sector)	Some: the Electricity Access Code contains some provisions addressing capex/opex forecasts	None	None	None
Analytical tools used by the regulator	Various tools have been used, including top-down and bottom-up approaches, statistical models, expert engineering judgement, planning process review	Various tools have been used. Provision for use of external productivity estimates to set growth rate of "default" prices without reference to capex/opex allowances	Various tools have been used, similar to AER	Various tools have been used, similar to AER	Various tools, including productivity estimates to set prices for part of the control period without an explicit capex/opex allowance	Various tools can be used	Various tools have been used, similar to AER. Ofgem has also developed incentives for accurate forecasts (the "menu" approach)
Ownership of electricity transmission and distribution networks	Both investor-owned and Government-owned	Transmission network is government owned; distribution utilities are investor-owned (or are exempt from price regulation)	Government-owned	Government-owned	Almost all Government-owned	Investor owned (plus small municipally-owned utilities)	Investor owned
Approximate timing (between NSP proposal and regulator decision)	11 months	8 months	14 months (electricity) 9 months (water)	9 months	8 months	11 months	24 months (a new "fast tracking" process may result in some decisions in about 6 months for qualifying proposals)
Cost of capital separate?	No (but appeals process has been separate)	Yes	No	No	Yes	No	No (appeal is of whole decision including cost of capital)

1.4 OBSERVATIONS AND RECOMMENDATIONS

11. In this section of the report we highlight particular features of the approach taken in the different jurisdictions that are relevant to the issues the AEMC asked us to address. We also offer some recommendations where features of other jurisdictions might be useful additions to the approach taken in the National Electricity Market (NEM).

12. **Degree of prescription:** some jurisdictions have very little prescription or explicit guidelines as to how the regulator is to exercise discretion in relation to capex/opex allowances (Great Britain, New Zealand, IPART). Other jurisdictions have quite extensive rules guiding how the regulator is to review forecasts (AER, ERA). For the AER, there is significant detail in the Rules about all aspects of the determination process, whereas in New Zealand there is more detail about the cost of capital process than there is about how capex/opex allowances are to be determined. In Great Britain there is almost no prescription or guidance about any aspect of the determination process, although the regulator typically describes its proposed policy approach before and during the determination process.

13. **Approach taken by the regulator**: although in some jurisdictions nothing is said about the process that the regulator should use, and in other jurisdictions quite a lot is written down, the approach taken by each regulator (including the AER) is very similar. Universal elements are:

- use of technical engineering consultants;
- comparison of forecasts to out-turn costs in prior period, as well as to forecasts and adopted allowances in prior period;
- combination of top-down and bottom-up analyses;
- a variety of analytical tools developed by the regulator to address particular issues of importance arising in each determination.

14. **The company's proposal is the starting point**: it seems to be inevitable that the regulator will take the company's proposal as a starting point, whether or not this is explicitly required by the relevant rules. We note that in some jurisdictions, including the NEM, the NSP formally makes a "proposal" for its revenue requirement and prices in the upcoming control period. In other jurisdictions (for example, Great Britain), the NSP provides cost forecasts to the regulator but does not formally request a revenue requirement. It is not clear that this represents a difference of substance, for example in the weight to be given to the NSP's forecasts. Given that the NSP's role and expertise is in

managing its own systems, it seems proper that the NSP application should be the starting point (this is also consistent with procedural fairness). The only case we reviewed in which the regulator does not start from a NSP proposal is the "default price path" approach in New Zealand, which is intended to be a "light-touch" approach. There is no "application", and the NSP has the option of requesting a "customized" approach—in which case the NSP application would then be the starting point. We would not expect an approach that substantially ignored the NSP's proposal, in favour of an "external" benchmark, to be successful. However, we also think that the regulator should be able to make "top-down" adjustments to the NSP's proposal where this is justified.

15. **Whether to "reject" or "adjust" the NSP's proposal**: we have seen that, in some jurisdictions (AER, ERA, NZ), the rules require the regulator to test whether the NSP's forecast is acceptable, where "acceptable" is in relation to criteria such as "reasonableness", and only to adjust the forecast if it is unacceptable. In other jurisdictions (Great Britain), the regulator's goal is simply to set a forecast. Sometimes these are described as different approaches: with the former approach the regulator can only adjust the threshold if it can be shown that the forecast is unacceptable, whereas with the latter approach no test needs to be satisfied before the regulator is able to adjust the forecast. The former has been characterized in terms of a "range of reasonableness", with the regulator only able to adjust if the NSP's forecast is outside this range, while the latter approach allows the regulator to adjust the NSP's forecast if the regulator can identify a "better" one. We suspect that this is a false distinction, or at least an unhelpful way of characterizing what regulators do in practice. We have not seen other regulators present their decision-making in terms of a two-step process. In our view, regulators should (and do) weigh all of the relevant evidence. If the NSP forecast is not well-supported by the evidence, the regulator will place less weight on the NSP's forecast and more weight on other information available to it from the regulator's own analysis and the advice of technical consultants.

16. **The importance of good information**: the regulator's ability to conduct a critical and effective review of NSP forecasts depends on the availability of good quality information about historically-incurred costs, as well as forecast future costs and the business cases that underlie the forecasts. In this context, "good quality" may encompass: recent years' time series of sufficient length; sufficient detail (costs allocated to a number of individual projects or programs); consistent definitions over time; accurate, audited data. In many jurisdictions (GB, New Zealand, Ontario, AER), the regulator collects historical

data through a process which is separate from the price reset process (typically, the NSP is obliged to file "regulatory accounts" annually, though the level of detail varies across the jurisdictions we have reviewed). The design of the regulatory accounts often evolves over time, and benefits from a collaborative approach between the regulator and the industry. It may be necessary for the detailed design of regulatory accounts to be kept under review and to evolve over time, but there is likely to be merit in standardizing the type and format of information collected from different companies (to facilitate comparisons, and to make the regulator's analysis more efficient). For example, Ofgem has spent a great deal of time in developing a format for data tables to be submitted by companies, and has then worked closely with companies to ensure that the data they provide is fit for purpose and consistent. Obtaining consistency, particularly across companies, appears to be difficult in practice, and is still an on-going process for Ofgem. Ofgem's experience is also that data on the quality and condition of assets is needed, in addition to accounting data.

17. **Regulators use a variety of analytical tools**: each regulator seems to develop its own analytical tools in response to particular issues that arise in the context of specific access arrangement or price/revenue determinations. If asset replacement expenditure is a significant issue, the regulator may develop tools aimed at assessing whether the NSP's replacement program is reasonable. In a different reset, it may be that unit cost inflation is a key issue, and tools will then be developed to address that. None of the jurisdictions we reviewed prescribed the use of particular tools (or proscribed others). Regulators should be (and typically are) free to develop analytical tools to address the problems they perceive to be significant, without constraint in rules. We are not aware of any examples where the use of statistical or other analytical tools is an effective *substitute* for regulatory judgement. We are aware of instances where regulators have relied on extending historical cost trends without considering explicit cost forecasts, but we are not aware of any examples of a regulator successfully setting prices over extended periods in this way. The approach in Ontario and Rhode Island is a hybrid, with explicit cost forecasts only for the first year or two of a new control period, and a trend-based increase thereafter. However, in both jurisdictions changes have been implemented or are under consideration to introduce a greater forecasting element, particularly for capex.

18. **The NSP's processes for developing forecasts are also important**: regulators and their technical advisors typically (AER, NZ, Ofgem, ERA) try to review the *processes* the NSP used to develop its forecasts, as well as the forecasts themselves. If companies can

demonstrate that good practice was followed, the regulator may not need to put as much effort into reviewing the forecasts themselves. In that situation, it may be appropriate for the regulator to put relatively more weight on the forecasts that the NSP has produced when weighing this and other evidence in reaching a judgement on what costs to allow.

19. **Menu approach**: Ofgem has developed an incentive arrangement which is designed to reduce the possibility of bias in the forecasts submitted by the NSPs. This is not so much a tool for analysing NSP forecasts as an add-on to the standard building-blocks approach (somewhat like an efficiency carry-over scheme) which works by providing an incentive to the NSPs to provide accurate forecasts. We note that this approach seems to be beneficial, but that it does not remove the need to analyse the NSP forecasts. Furthermore, we understand that the current Rules do not allow for the development of such a scheme in the NEM.

20. **Use of "output measures"**: in part, it is difficult to forecast efficient capex/opex amounts because required spending may be influenced by uncertain external factors. For example, an NSP's ability to go ahead with a planned reinforcement project may depend on obtaining relevant planning permits, the timing of which can be very uncertain. In most of the jurisdictions we examined, the regulator is able to make part of the capex/opex forecasts "contingent" on external events in some way, or to update allowances during the control period, at least for transmission investment. Ofgem has used explicit output measures to drive allowed revenues for some time: for example, DNSPs have had an allowance for the cost of connecting generators that automatically increases with the volume of generation connected. Ofgem is increasingly using output measures to provide direct financial incentives to the NSPs in other areas, for example in relation to environmental impacts (e.g., losses) and customer satisfaction.

21. **Treatment of transmission and distribution**: *a priori*, we would expect that the rules for assessing forecasts from transmission and distribution businesses should be the same. In practice, it may be that different techniques will be used—for example, because transmission forecasts are more easily characterized as a small number of large "projects", whereas distribution forecasts look more like a set of "programs". As discussed above, there is frequently (NZ, Ofgem, ERA, AER) a mechanism for updating authorized transmission investment programs during a control period, for example because the need for upgrades may be contingent on uncertain new demand, or because upgrades may be held up by planning issues. It is appropriate for the differences between transmission and

distribution activities to be reflected in the Rules. It is not clear to us that all of the differences between Chapters 6 and 6A at present reflect fundamental differences between distribution and transmission.

22. **Assessment of the building blocks individually or in aggregate**: in some jurisdictions (Great Britain), more emphasis is put on whether the total revenue requirement is reasonable than on getting each building block just right. In Great Britain, for example, the NSPs cannot appeal the regulator's cost of capital decision without also opening the other building-blocks to re-hearing. In other jurisdictions each building block seems to be determined more or less in isolation. For example, in the NEM and in New Zealand, there are detailed rules for each of the building blocks, and the regulator's decision on each of the building blocks appears somewhat separate and distinct (for example, a separate process sets the cost of capital in New Zealand, and in the NEM the elements of the AER's determination can be individually appealed). An approach which allows for settlements and negotiation (between the NSP and a formal "customer representative") is really focussed only on the total revenue requirement, in which case less attention is likely to be paid (explicitly) to the capex/opex forecasts in isolation.

23. **Interaction between the NSP and the regulator**: during the review process, there is "working-level" interaction between the NSP, the regulator, and the regulator's technical consultants. This interaction is focussed on obtaining missing information, and involves mainly the NSP's operations staff and the staff of the regulator. Separately, there is a formal process whereby the regulator will publish a draft decision and the NSP will publish a response. Typically, where the regulator relies on technical advice from consultants, the NSP will review a draft of the consultants' report to give the NSP an opportunity to correct factual errors. These interactions seem to follow very similar processes in all the jurisdictions we examined. In some jurisdictions there is an additional "senior-level" interaction between the regulator and the NSP—for example, the NSP's senior director responsible for regulation, or even the CEO, might meet with members of the regulatory board that will ultimately be taking decisions on the determination. In other jurisdictions, no such contact takes place while a price review is taking place. We are not sure whether it is necessary for senior-level contact to take place during a review, but, if it does, there should be a formal process associated with the interaction. While the degree of interaction between the NSP and the regulator varies across the jurisdictions we have examined, we have not seen the process characterized as "negotiation" between the NSP and the

regulator. The only examples of formal negotiation are in those jurisdictions where there is a formal “settlement” process, involving the NSP and customer representatives as well as the regulator.

24. **Timescales for the review**: we observe a range of timescales for decision-making in the different jurisdictions. For example, in New Zealand the timetable for a distribution determination is 150 working days between proposal and decision (approximately 8 months). This is shorter than the AER’s process which takes about 11 months (although we note that the AER’s process includes elements of cost of capital determination, whereas the Commerce Commission’s does not). Ofgem’s process is considerably longer, taking about 24 months between business plan submissions and final decisions. We also note that Ofgem’s process envisages that there will be no new data submitted in the last 9 months of the process. Ofgem is in the process of implementing a “fast-track” process for NSPs with business plans that meet certain criteria. The fast-track process might take only six months or so. Some regulators (AER, New Zealand) have to make a decision within statutory timescales, others (Ofgem) do not.

25. **Consumer representation**: most regulators have an implicit or explicit “customer interest” function. In North America it is more common for an organisation separate from the decision-making part of the regulator to act as a “consumer representative”. In some jurisdictions (for example, Rhode Island) the task of the regulatory commission can be represented as examining the competing proposals of the NSP and the consumer representative, and weighing the evidence presented by the two sides. In this case, the regulator itself may undertake limited additional analysis (rather relying on the analysis performed by the NSP and the consumer representative). In North American jurisdictions it is common for regulators to be able to approve a “settlement” between the NSP and an official customer representative, as an alternative to making an explicit determination.

26. **Ownership structures**: we note that in some of the jurisdictions we reviewed most or all of the NSPs are investor-owned (Great Britain, New Zealand),[9] whereas in others there is significant government ownership (ERA, NSW, AER, Ontario). A diversity of ownership structures may introduce additional complications (for example, we have seen examples of NSPs operating under a government-imposed budget constraint, in addition to the revenue

[9] In New Zealand the TNSP is State-owned, and there are some customer-owned DNSPs (which are not subject to price-quality regulation).

cap imposed by the regulator). Outside Australia, the jurisdictions we reviewed where assessing cost forecasts is a central part of the determination process have only investor-owned utilities.

27. **Regulatory frameworks evolve over time**: we suspect that some aspects of the regulatory frameworks we have reviewed are a function of circumstances unique to that jurisdiction, and/or the history of the sector in that location. For example, while Ofgem has been determining revenues for the NSPs for 25 years, New Zealand has a much shorter history of NSPs operating under explicit revenue caps. Some of the difference we observe in rules and practices may well be due to the influence of history and other unique circumstances.

1.5 Conclusions About the AEMC's Policy Intent and Best Practice

28. In the discussion above we have made some recommendations about best practice on the basis of our review. For example, assessing cost forecasts requires detailed information, prepared on a consistent basis across firms and over time, on historically-incurred costs as well as the forecasts. Best practice would therefore include the AER collecting data on an annual basis, and improving the scope and design of the data collection exercise over time.

29. In the context of the AER's rule change proposal, the debate about how the AER should assess NSP capex/opex forecasts is partly about regulatory discretion more broadly, and the degree to which that discretion should be guided by the Rules. Regulatory discretion may be required in determining other of the building blocks that go to make up the overall revenue determination. For example, there are explicit rules about how the AER is to calculate the return on capital, whereas Ofgem's decision on the return is guided only by general principles.[10] The general question of whether the exercise of regulatory discretion should be guided by written rules is outside the scope of our study. However, in relation to discretion in assessing capex/opex forecasts, we have considered two subsidiary questions in reviewing rules and practice in other jurisdictions:

- Are the approaches of different regulators guided by explicit "rules"?
- Do rules constrain the *type* of analysis that regulators use?

[10] In practice, Ofgem's cost of capital decisions are likely to follow methods used in prior decisions, but there are no explicit rules guiding Ofgem's choice of methodology, and in practice the method has evolved over time.

30. The answer to the first question is that some regulators are guided by explicit rules: in addition to the AER, the ERA, IPART[11] and the NZ Commerce Commission must follow explicit rules when taking decisions about capex/opex forecasts (albeit that the level of detail is different). However, other regulators are not: there are no explicit rules of this kind for Ofgem's assessment of capex/opex forecasts. Despite this difference, we do not observe the existence of explicit rules constraining the *types of analysis* that may be undertaken in assessing NSP cost forecasts.

31. From our review of recent determinations in each jurisdiction, our assessment is that each regulator tends to develop analytical tools that are helpful in the context of specific issues that arise in each determination. The overall approach taken by each regulator seems very similar: technical consultants are hired to review the NSP forecasts (and the NSP *processes* used to derive the forecasts); benchmarking or other comparisons across firms are employed; and the regulator reviews actual costs in the current period, and trends over time. This is not to say that each regulator uses the same precise methods, but rather that each one develops tools useful to the circumstances of a particular determination, and tends to develop new tools or improve the old ones over time. We do not observe that regulators operating under explicit rules do less analysis or are unable to use certain tools (for example, benchmarking) that are used elsewhere.

32. One exception is that Ofgem has developed and implemented an approach aimed at reducing the degree of potential bias in the NSP forecasts through offering an explicit reward for accurate forecasts (the "information quality incentive" or "menu" approach). This is not really an analytical tool, it is an additional incentive mechanism added to the usual building-blocks approach. Adopting this approach does not lessen the importance of Ofgem being able to analyse NSP forecasts.

33. In our view, even if explicit rules do not constrain the *type* of analysis undertaken, they may well influence the *weight* put on the results of different analyses. In particular, rules may influence the weight that the regulator puts on its own analysis (e.g., benchmarking) relative to the weight put on the NSP's evidence. To the extent that less weight is put on the regulator's analysis, implicitly more weight is put on the NSP's own forecast. We have not found any evidence that different regulators systematically put more or less weight on the NSP forecast, relative to their own analysis. However, this is not

[11] At least, IPART's electricity NSP revenue determinations, under the National Electricity Code.

surprising because regulators are not explicit about weights in a way that facilitates comparison across jurisdictions (or even between different determinations in the same jurisdiction). While regulators typically give reasoning when they provide an allowance that is different from the NSPs forecast, the reasoning necessarily depends heavily on the facts at issue, which are different in each determination. In our view, the only way in which the question of weights, and the degree of upwards bias, could be elucidated is through a detailed review of a specific decision, such as might take place in the context of an appeal.

34. One specific point raised by the AER is that requirements to set allowances "based on the proposal" and "adjusted only to the extent necessary", act as a constraint. This point was not discussed in the AEMC's Chapter 6A determination, so it is unclear what AEMC's policy intent was in this regard.[12] There is also ambiguity over whether Chapter 6 of the Rules imposes more restrictions on the exercise of the AER's discretion than does Chapter 6A.

35. We would make two points about this aspect of the appropriate policy approach. First, in reviewing other jurisdictions we have noted some difference of approach to capex/opex allowances as between transmission and distribution, relating to fundamental differences between the two networks.[13] However, it is not clear to us that all of the differences between Chapters 6 and 6A reflect any underlying fundamental differences between transmission and distribution. Removing unnecessary differences might be beneficial.

36. The second point we would make on this issue is that we are not clear how such restrictions would constrain the AER if they do indeed operate in practice constrain. We think that, in practice, any regulator will always take the NSP's proposal as a starting-point for its analysis, and we are thus unsure what possible outcomes could be ruled out by these restrictions.

37. It is possible that the policy intent was to rule out an entirely "external" approach to forecasting costs, such as relying exclusively on an industry productivity trend. We are sceptical as to whether such an approach is ever likely to be appropriate (for energy

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[12] This language appears in Chapter 6, which was written after Chapter 6A.

[13] For example, transmission capex is likely to include a small number of large projects, the timing of which may be uncertain and driven by external events. Thus regulators have often developed a way of updating allowances during the control period accordingly.

networks at least) in any case.[14] In contrast, a proper use of benchmarking analysis—in which the regulator considers both "external" evidence and the NSP's own cost forecast—should not be ruled out.

38. We also think that any regulator will always seek to explain its decision with reference to the differences between the NSP's proposal and the regulator's decision. However, it may be that neither "adjusted only to the extent necessary" nor "based on the NSP proposal" are helpful guides to the exercise of the regulator's judgement, in particular, if this were interpreted to rule out "top-down" adjustments. We do not believe that it would be beneficial for the regulator's discretion to be constrained in that way. It may be that clarification of the policy intent in this regard would be beneficial.

39. The regulator's ability to reject unsupported forecasts gives the NSP an incentive to make forecasts that are well-supported. With a comprehensive set of historical data, and access to the full range of analytical tools, the regulator is able to identify and reject unsupported claims with more confidence. Over time, as the regulator improves data collection efforts and develops new analytical tools, the "bar is raised" in terms of what the NSP can be expected to do to support its forecasts.

1.6 RECOMMENDATIONS FOR IMPROVING THE NEM FRAMEWORK

40. Based on our review of how regulators in different jurisdictions assess NSP capex/opex forecasts, we have identified some ways in which the current NEM framework might be improved.

41. **A similar approach for distribution and transmission**: the policy intent (and presumably, therefore, the Rules) applying to transmission and distribution should reflect underlying differences between the sectors, but otherwise the approach to assessing capex/opex forecasts should be consistent. The only difference we observe in how transmission and distribution are treated in other jurisdictions is that a "contingent projects"-type process is more commonly used for transmission than distribution. Our recommendation is that the process for assessing capex/opex allowances should otherwise be the same. The drafting of Chapters 6 and 6A is currently different, but it is not clear

[14] We note that the New Zealand framework sets "default" price paths without reference to an "application" as such, since there is no application in the default mechanism. However, the NSPs have the option of making an application for a "customized" price path.

whether the differences reflect a different policy intent. We have not identified any reason to take a different policy approach in the two sectors.

42. **The policy intent is in some respects unclear**: the AEMC's policy intent stated that it was not correct to characterise acceptable forecasts as being somewhere in a reasonable range, yet at the same time the AEMC rejected a "best estimate" approach. The AEMC also stated that the AER's ability to reject the NSP proposal should provide a disincentive for ambit claims. These statements seem to be somewhat inconsistent, and probably have not resulted in a clear expression of the underlying policy intent. This lack of clarity is reflected in the debate over whether the Chapter 6 requirements (that allowances be based on the NSP proposal and be adjusted only to the extent necessary) introduce upwards bias. We recommend that the policy intent for both transmission and distribution should be clarified so that it is clear that the AER should consider all relevant evidence as to the reasonableness of the NSP capex/opex forecasts.

43. **Guidance to the AER should reflect principles, not specific tools or kinds of analysis**: we note that in some jurisdictions (Great Britain, New Zealand) there is little or no guidance beyond short statements of principle (similar to what is found in the NEL). We also observe that regulators in different jurisdictions, including the AER, use a range of analytical tools in assessing NSP forecasts. We have not seen any regulators successfully making use of statistical tools, models, or other analytical methods as a substitute for exercising appropriate judgement as to the reasonableness of cost forecasts. Therefore we do not recommend that there should be guidance to the AER as to the types of analysis that should be employed. For example, it might be appropriate to require the AER to take into account the NSP forecast, but to consider in addition other evidence presented by stakeholders or generated by the AER's own analysis. We do not recommend an approach that would allow the AER to "reject" the NSP's forecast before determining a substitute allowance that is based purely on an "external" benchmark but does not in any way take account of the NSP forecast. We have not seen regulators elsewhere successfully applying an approach that takes no account of an NSP forecast.

44. **The AER needs good data**: regulators in other jurisdictions have put considerable effort into improving the data they collect from NSPs and use in various kinds of analyses relevant to assessing the NSP cost forecasts. In particular, good practice involves annual data collection outside the determination process, and regular interaction with the NSPs to keep the scope of the data collection under review. Data may be required on aspects of

network performance, and asset condition, in addition to costs (historical and forecast). We note that Ofgem has continually adjusted its data collection process over many years as it has sought to improve the usefulness of the data. We also note that, in New Zealand, NSPs will be required to obtain independent third-party review of the reasonableness of their forecasts (and forecasting methodologies) prior to submitting their proposals.

45. **There are some "tools" which may improve how capex/opex allowances are used in the determination process**: separate from how the regulator analyses the NSP forecast, there are tools which can improve how the forecast is used in the building-blocks determination. One such tool is the use of "output measures", such as MW drivers associated with load growth or new generator connections. If output measures can be identified that drive costs, it may be possible to link the capex/opex allowance to the output measure, thereby reducing uncertainty and exposure to forecasting inaccuracy. If this can be done effectively, it may indirectly facilitate assessment of the NSP forecast by reducing some of the associated uncertainty. A second such tool is the use of a "menu" approach to determining capex/opex allowances (as used by Ofgem). This does not avoid the task of assessing NSP forecasts, but the approach is designed to provide the NSP with a direct financial incentive to provide a reasonable forecast. We recommend that, over time, the framework in the NEM should evolve to allow the use of such tools—we note that implementation of these tools is a significant undertaking that would require substantial resources from the regulator and the NSPs, and that careful analysis is likely to be needed to avoid unintended consequences.

2. INTRODUCTION AND APPROACH

2.1 CONTEXT

46. The "building blocks" approach to setting the revenue requirement for energy network businesses is used in many jurisdictions around the world. Under this approach, a forecast of future capital expenditure (capex) and operating costs (opex) is one of the inputs for calculating the total revenue requirement over the upcoming control period.[15] This study is about how an appropriate allowance for future capex/opex is determined by the regulator.

47. The Australian Energy Regulator (AER) has proposed a change to the part of the National Electricity Rules (the Rules) that addresses how the AER should determine capex/opex allowances.[16] The Rules set out the circumstances in which the AER must accept a network service provider's (NSP's) forecast, and how the AER is to determine the allowances if the NSP's forecast cannot be accepted.

48. The AER's proposed rule change refers to restrictions on the AER's ability to reject NSPs' capex/opex forecasts and the requirement that the regulator must accept a forecast if it reasonably reflects certain criteria listed in the Rules. The AER considers that the current Rules invite upwardly biased forecasts and limit its ability to interrogate and amend forecasts provided by NSPs. The AER also considers that it has less discretion than regulators in other jurisdictions. In consequence, the AER is proposing to change the Rules to remove some of the perceived constraints on its approach.

49. The Australian Energy Market Commission (AEMC) has expressed an initial view that its policy intent, when it designed Chapter 6A of the Rules, remains appropriate. AEMC has asked us to examine regulatory practice in assessing capex/opex forecasts in a range of jurisdictions, and to make comparisons with the practice of the AER. The objectives of our study are to describe rules and practices in each jurisdiction, identify what may be good practice, and determine whether the policy intent behind Chapter 6A of the Rules remains consistent with good practice.

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15 In this report, unless otherwise noted, we discuss the general approach taken by each regulator without, for example, distinguishing between price caps and revenue caps.

16 The AER's rule change proposal, as well as the AEMC's initial views, are described in the AEMC's directions paper (see chapter 3 of *Directions Paper National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012 National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, AEMC (March 2012)).

50. In this report we do not comment on how well the current Rules capture the AEMC's policy intent or on how the current Rules may have constrained the AER's practice, since that is ultimately a legal question. We have examined Chapters 6 and 6A of the Rules in order to relate the current debate and the AER's rule change proposal to the policy intent behind the current Rules. We have compared the AEMC's policy intent, and the AER's practice, with rules, policy and practice elsewhere, in order to determine whether the AEMC's policy intent remains consistent with good practice.

51. The AEMC asked us to review the regulatory schemes in Great Britain, New Zealand, New South Wales and Western Australia, and also to recommend two relevant jurisdictions in North America (we reviewed Ontario and Rhode Island).

52. We note that, while the "building blocks" approach is adopted by regulators in many jurisdictions, it is not commonly used in North America. North American regulatory practice, with some exceptions, is to set prices on the basis of historically-incurred costs (after testing for prudence). We have examined two jurisdictions which are exceptions and in which an element of forecasting is used to set prices.

53. The AEMC's policy intent in relation to the assessment of capex/opex forecasts was set out in its draft and final decisions on Chapter 6A of the Rules (which deals with transmission).

54. We note that the AEMC is considering other rule change requests alongside the one relating to capex/opex allowances, including one relating to how actual capex from the prior regulatory period is rolled in to the opening asset base at the start of the new period. Under the current Rules there is no prudence review—all capex spend is rolled into the opening asset base. The AER has expressed concern that the current approach has poor incentive properties which could be resulting in inefficient outcomes. The work on capex incentives is separate from (and outside the scope of) this study. However, in our view, the exercise of regulatory discretion in connection with setting capex allowances is qualitatively different from exercising discretion in respect of whether past capex should be rolled in to the asset base. The latter discretion can have a direct influence on investment incentives, and the "under-investment problem".[17] Nevertheless, in this report we have

[17] *Preliminary views for the AEMC*, paper by George Yarrow, available on the AEMC's website at http://www.aemc.gov.au/Media/docs/Professor-George-Yarrow-c4794217-ac6d-4927-a9fb-1a55d09b38cd-0.PDF

noted whether regulators are required to assess prudence of past capital expenditure, because it appears that, in practice, this task is frequently carried out in parallel with reviewing capex *forecasts*, for example through the use of technical consultants, and perhaps because both tasks require the same data and expertise.

2.2 THE AEMC'S "POLICY INTENT" BEHIND CHAPTER 6A OF THE RULES

55. Chapter 6A of the Rules deals with electricity transmission and how the AER is to make determinations for transmission NSPs. The AEMC wrote this part of the Rules, and set out its policy intent behind Chapter 6A in its draft and final determinations.[18] Two specific issues which were discussed in the AEMC's determination are worth highlighting: the extent of the AER's discretion in setting allowances (relative to the TNSP's forecast), and the degree of precision that may be expected in determining a forecast of efficient costs. The AEMC discussed these issues in its March 2012 *Directions* paper, referring back to the Chapter 6A Rule Determination.[19]

> *The Chapter 6A rule determination contains useful explanatory material in respect of the decision-making requirement. The AEMC stated that it intended that the AER would not be "at large" in being able to reject a TNSP's forecast and replace it with its own, and that the AER must have regard to the information in the NSP's regulatory proposal. This is an important point of policy made clear by the AEMC; the NSP's regulatory proposal is the AER's starting point and represents the most significant evidentiary consideration for the AER. The constraint on the AER's power of substitution is that the substitute meet the test of efficiency, prudency, and a realistic expectation of cost inputs. At the time of making Chapter 6A, the AEMC did not think that expenditure forecasts could be specified with precision; meaning that there is no best or correct figure. At the same time though, the AEMC did not intend that the NER contemplate a range of permissible outcomes such that there could be a bias towards a higher amount. The AEMC specifically avoided referring to a reasonable estimate, or imposing a legal burden of proof.* [omitted footnotes cite the 2006 Determination]

56. While the AEMC intended to constrain the AER's ability to replace a TNSP's forecast with its own, the AEMC did not intend to limit the kinds of analysis that the AER would be able to bring to bear on the TNSP's forecast: "The AEMC considered that the

18 *Draft National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006*, AEMC (July 2006) and *National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18*, AEMC (November 2006).

19 AEMC *Directions Paper*, March 2, 2012, p. 16.

AER would use a range of techniques and inputs to test the forecasts of costs provided by NSPs".[20]

57. We note that the current debate—over the degree of regulatory discretion, and the risk of upwardly-biased forecasts—is thus not new. Similar issues were raised in the 2006 Determination.

58. The AER has said that its proposed rule change:[21]

- *amends the decision making test to require that the AER must determine the forecast of expenditure that the AER considers a prudent and efficient NSP would require to provide a safe and reliable electricity service*
- *removes the restrictions that limit the AER's ability to determine an impartial forecast*
- *enhances the mechanisms available to manage uncertainty in the determination of forecasts.*

59. The AEMC's Directions paper explains that the rule change would require the AER:

> *to determine the total of capex or opex which would represent the efficient capex or opex required by a prudent NSP to achieve the capex or opex objectives (which themselves would remain unchanged).* [f/n omitted] *Thus, there would no longer be a reference to the NSP's regulatory proposal in the capex and opex criteria, and the AER's decision would no longer be required to approve or reject this.*[22]

60. This suggestion seems to reflect the debate in 2006 over whether a "best estimate" test should be preferred to a "reasonable estimate",[23] in connection with the need for the regulator to exercise judgement in determining capex/opex allowances. The AEMC determination discusses the need for the regulator to balance the interests of NSPs and customers in exercising this judgement, and for the Rules to provide guidance as to the exercise of that judgement. The AEMC concluded, in part:[24]

> *The Commission believes that the subject of the regulation – the forecast capital expenditure and operating expenditure for substantial, highly complex and technical infrastructure for a five-year period is not a matter that is amenable to the level of precision and confidence that would enable one to sensibly say there is one correct or "best" figure. It considers that Rules that*

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20 *Id*.

21 *Economic regulation of transmission and distribution network service providers: AER's proposed changes to the National Electricity Rules*, AER (September 2011), p. 19.

22 AEMC's directions paper, p. 17.

23 See AEMC's November 2006 Determination, section 4.1.

24 *Ibid.*, p. 52.

> *could be interpreted in that way are likely to result in a heightened risk of regulatory error. Equally the Commission does not intend that the Rules contemplate such a range of permissible outcomes that there is a risk of inherent bias toward higher amounts.*

61. We also note that part of the AER's current concern is that, in cases where it is obliged to reject an NSP's forecast, the AER has a limited ability to move away from that (unreasonable) forecast. In respect of distribution NSPs, the AER has an additional concern which comes, in part, from the fact that Chapter 6 of the Rules[25] is different from Chapter 6A. The AER says:[26]

> *Under clause 6.12.3(f), 'if the AER refuses to approve* [the DNSP's capex/opex forecast]*, the substitute amount or value on which the distribution determination is based must be: determined on the basis of the current regulatory proposal; and amended from that basis only to the extent necessary to enable it to be approved in accordance with the Rules.'*

62. The explicit requirement to amend the NSP's forecast "only to the extent necessary" is in Chapter 6 but not in Chapter 6A of the Rules. This idea was not discussed in the AEMC's determination of Chapter 6A of the Rules, and so may not be compatible with the AEMC's Chapter 6 policy intent.

63. Chapter 6A of the Rules requires that, if the AER does not accept the TNSP's forecast, it is to determine "an estimate of the total of the Transmission Network Service Provider's required operating expenditure for the regulatory control period that the AER is satisfied reasonably reflects the operating expenditure criteria, taking into account the operating expenditure factors".[27] However, Chapter 6A does contain a requirement similar to Chapter 6 (that the AER should only adjust the TNSP's proposal as far as is necessary)—but the requirement applies to the other building blocks, with the exception of the capex/opex forecasts. Section 6A.13.2 states:

> *If the AER's final decision is to refuse to approve* [the TNSP's proposed maximum revenue]*, the AER must include in its final decision a substitute amount or value which, except* [in relation to the capex/opex forecasts]*, is:*
>
> *a) determined on the basis of the current Revenue Proposal; and*

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25 Chapter 6 of the Rules was not written by the AEMC, so the policy intent behind Chapter 6 may be different from that behind Chapter 6A.

26 *Response to AEMC consultation paper Economic Regulation of Network Service Providers*, AER (December 2011), p. 10.

27 6A.14.1(2)(ii).

b) *amended from that basis only to the extent necessary to enable it to be approved in accordance with the Rules.*

64. So far as we are aware, the requirements of section 6A.13.2 were not discussed in the AEMC's draft or final determinations.

65. A final complication is that, while Chapter 6 has the "based on the proposal" and "only to the extent necessary" requirements and Chapter 6A does not, the AER considers that it operates under effectively the same requirements for transmission as distribution. The AER states: "the substitute amount determined by the AER in the draft decision will be the forecast proposed by the network business adjusted for any specific forecast costs identified that require amendment before they could be approved in the final decision. Accordingly, when issuing a draft [transmission] decision, the Chapter 6A provisions have the same practical effect as the Chapter 6 provisions that require that the AER's response be based on the regulatory proposal".[28] The AER goes on to say (about transmission determinations):

> *As a result of this continued focus on the revenue proposal and to ensure procedural fairness to the stakeholders, the AER experience is that the process of determining a substitute in the final decision does not allow it to completely set aside the revised proposal in determining a substitute. This has been a claim made by some stakeholders. Rather, the AER has found that the intended two stage process, where the AER first determines that it is not satisfied and then determines a substitute, becomes conflated to a one stage process. In this practically conflated process, the reasons and justifications for finding that the AER is not satisfied that a proposal reasonably reflects required expenditure also becomes the justification for the substitute figure. Accordingly, again the substitute figure becomes the forecast proposed by the business minus any specific issues that have been identified by the AER in its analysis of the revenue proposal.*[29]

66. The AER believes that, despite the differences between Chapters 6 and 6A highlighted above, the two parts of the Rules have the same effect, because:

- both chapters require the AER to take account of the "expenditure factors", one of which is "the information included in or accompanying the Revenue Proposal" (we discuss the expenditure factors in more detail below),[30]
- the AER is required to give reasons for its decisions, including "the values adopted by the AER for each of the input variables in any calculations including:

[28] AER's response to the AEMC consultation, AER (December 2011), p. 8.

[29] AER's response to the AEMC consultation, AER (December 2011), p. 9.

[30] See section 3.

- whether those values have been taken or derived from the network business' proposal, and
- if not the rationale for the adoption of those values"[31]

- for draft transmission determinations, "if the AER refuses to approve [the proposed revenue], the AER's draft decision must include details of the changes required or matters to be addressed before the AER will approve [the proposed revenue]".[32]

67. We conclude that the AEMC's policy intent in relation to capex/opex allowances for TNSPs was that a "reasonable estimate", rather than a "best estimate" test, should be used.

68. It is not clear to us what the AEMC's policy intent was in relation to whether the AER's decision should be "based on the proposal" or "adjusted only to the extent necessary", because this was not discussed in the AEMC's determination.

69. In its determination, the AEMC said:

> *The decision-making process set out in the Revenue Rule will also reduce the incentive for TNSPs to submit forecasts which represent ambit claims. Such exaggerated forecasts would be likely to fail to satisfy the decision criteria to be applied by the AER and therefore to run the risk of being rejected and replaced by the AER with a less favourable forecast…*
>
> *…Under the Revenue Rule, the AER is required to exercise judgement in deciding whether it is satisfied that the forecasts reflect the specified criteria, having regard to the specified factors. However, the exercise of that judgement is constrained and guided by the need to be satisfied as to the efficiency and prudency of the forecast and that cost forecasts reflect realistic expectations. In exercising its judgement the AER must also have regard to the information provided in the TNSPs proposal and the other evidentiary considerations specified in the Rule. That is, the AER is not at large in being able to reject the TNSPs forecast and replace it with its own. It must also provide reasons in terms of the decision criteria and the factors for both a rejection of the forecasts and their replacement with forecasts that it considers do meet the requirements of the Rule.*[33]

70. The policy intent behind Chapter 6 of the Rules is discussed in explanatory material published by the Standing Committee of Officials of the Ministerial Council on Energy (SCO) in April 2007.[34] We have reviewed these documents, but have not found any explanation of a different policy intent that is linked to the differences between Chapters 6

31 Section 6A.14.2(2).

32 Section 6A.12.1(c).

33 AEMC determination, p. 53.

and 6A discussed above.[35] However, we do note two relevant comments from stakeholders in the consultation process. In response to a retailer comment that the "propose–respond" model would lead to higher costs, the SCO responded: "SCO intends the AER to have sufficient discretion to reject inflated capital and operating expenditure proposals through the operation of these rules and having regard to the capex and opex principles proposed for these provisions. Should the Rules be interpreted in a way that results in a systemic upward bias in returns, this matter is best dealt with through the rule change process".[36] A network requested that there should be explicit weights on the criteria to be used for assessing the capex/opex forecasts. The SCO responded: "Not Accepted. The clause provides sufficient guidance. Placing weightings on the opex or capex criteria would limit flexibility in considering the unique circumstances of the distribution business during a regulatory determination process".[37]

71. We conclude that there is ambiguity over whether Chapter 6 of the Rules imposes more restrictions on the exercise of the AER's discretion than does Chapter 6A, and over whether the AEMC's policy intent was for AER's decision to be "based on the proposal" or "adjusted only to the extent necessary". Nevertheless, we are also unsure as to how these two restrictions would, in practice, constrain the AER. We think that, in practice, any regulator will always take the NSP's proposal as a starting-point for its analysis—if the alternative implies that the regulator might look only at "external" benchmarks.[38] We are not aware of any examples of a regulator being able to rely solely on external benchmarks or statistical analyses without also taking into consideration the NSP's cost forecast.

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34 *Changes to the National Electricity Rules to establish a national regulatory framework for the economic regulation of electricity distribution, Explanatory Material*, MCE (April 2007) and *SCO response to stakeholder comments on the Exposure Draft of the National Electricity Rules for distribution revenue and pricing* (section 6).

35 The SCO did say "The Exposure Draft takes into account differences in the nature of transmission and distribution networks, based on analysis of these differences undertaken during the development of the draft Rules." (Explanatory material, p. 5).

36 Table of Stakeholder Comments, p. 25.

37 *Id.*, p. 27.

38 We note that the New Zealand framework sets "default" price paths without reference to an "application" as such, since there is no application in the default mechanism. However, the NSPs have the option of making an application for a "customized" price path.

72. We also think that any regulator will always seek to explain its decision with reference to the differences between the NSP's proposal and the regulator's decision. However, it may be that "adjusted only to the extent necessary" is not a helpful guide, in particular, if it were interpreted to rule out "top-down" adjustments. We do not believe that it would be beneficial for the regulator's discretion to be constrained in that way.

73. We have reflected further on these questions in reviewing the rules and practices applied in the jurisdictions we reviewed for this study.

2.3 OUR APPROACH

74. The AEMC asked as to review arrangements in Great Britain, New Zealand, New South Wales and Western Australia, and also to recommend two relevant jurisdictions in North America (we have reviewed Ontario and Rhode Island). The Australian jurisdictions are relevant because experience in these jurisdictions influenced the development of the NER. The approach in New Zealand is interesting because it has recently been reviewed, with the current approach being based, in part, on the NER model. In Great Britain, Ofgem has several decades' experience of assessing NSP cost forecasts, and has recently adapted its approach following a detailed review.

75. The North American approach to setting access prices, in general, takes a different approach. In most jurisdictions, North American regulators set prices based on actually-incurred historical costs. Forecasts of future costs either play no role, or only a limited role in setting prices.[39] However, some jurisdictions have experimented with more forward-looking approaches that involve elements of cost forecasting. We reviewed the approach taken in Rhode Island and in Ontario as illustrative of how North American regulators assess forecast costs.

76. For each jurisdiction, we have described how the regulator has in practice approached the task of reviewing capex/opex forecasts put forward by the firms it regulates. We have done this by looking at recent decisions in each jurisdiction. We have also described the extent to which practice in each jurisdiction is determined by rules that the regulator is required to follow, or policy guidelines that it has determined. Finally, in those jurisdictions

[39] In general, prices ("rates") are set on the basis of historic costs. In most jurisdictions rates are only reviewed on the request of the utility or a customer group. When costs are rising over time, rate cases become more frequent. Sometimes regulators may "pre-approve" rate increases to address expected future cost increases, but the usual approach is for the change in rates to recover *actual* cost increases rather than a forecast (through the use of a "unders/overs" mechanism).

where the framework is currently changing, we have reviewed proposals for change to look for material that could be relevant for our study.

77. In the chapters which follow, we describe the framework and approach taken by the regulator in each jurisdiction, based on our document review. We were also able to speak directly with staff at each of the regulators to check our understanding of various points, and to seek clarification. We are grateful to the regulatory staff who generously made time available to speak to us. We would also like to emphasise that any opinions expressed in this report are those of the authors alone. Any errors of fact are ours.

3. AUSTRALIA (AUSTRALIAN ENERGY REGULATOR)

3.1 INTRODUCTION

78. The AER is responsible for determining prices for access to distribution and transmission networks in the National Electricity Market (NEM). It does so by applying the National Electricity Rules (the Rules).

79. For this study we have reviewed how the AER assessed capex/opex forecasts in its regulatory determinations[40] for electricity distribution and transmission networks. We met with the AER to discuss the approach taken in recent determinations.[41]

3.2 OVERARCHING REGULATORY FRAMEWORK

80. The AER's approach to regulating the prices charged by electricity distribution and transmission companies is governed by the NEL and the NER. The national electricity objective is:[42]

> *…to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to - price, quality, safety, reliability and security of supply of electricity; and the reliability, safety and security of the national electricity system.*

81. The NEL also sets out "revenue and pricing principles",[43] which include:

> *A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in– providing direct control network services; and complying with a regulatory obligation or requirement or making a regulatory payment.*

82. In addition, the AER's process for determining revenue/prices must follow the prescriptions and guidelines set out in the Rules. The Rules address in some detail how the AER is to set capex/opex allowances, as we discuss below.

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40 By "determination" we mean the decisions AER takes under Chapters 6 and 6A of the Rules.

41 We are grateful to the AER staff for meeting with us and describing the approach taken in recent determinations. We used the meeting to clarify our understanding of how the AER assesses capex/opex forecasts, but any views expressed in this report, and any errors of fact, are those of the authors alone.

42 National Electricity Law, § 7.

43 National Electricity Law, § 7A.

3.3 THE PRICE DETERMINATION PROCESS

Form and Timing

83. AER uses a "building blocks" approach to determining the required revenue in the up-coming period. All of the building blocks, including the cost of capital, are considered together within the same process (although elements of the cost of capital may have been determined in a separate, generic "WACC review").[44] A single determination process will typically include all of the DNSPs (or TNSPs) in a particular State. Timing for distribution and transmission, and the different States, is typically somewhat staggered.

84. NSPs are required to submit a proposal 13 months before the end of the current control period.[45] The AER is required to assess completeness of the proposal and compliance with the guidelines "as soon as practicable".[46] A non-compliant proposal must be resubmitted within one month.[47] The AER may publish an "issues paper", and must publish a draft determination. The draft determination must be published as soon as practicable, but no later than seven months before the end of the current control period.[48]

85. We note that the AER has six months to issue a draft determination, or five months if the NSP's proposal was inadequate.

86. The NSP may submit a revised proposal within 30 business days of the draft determination, but any revisions are limited "the substance of any changes required by, or to address matters raised in, the draft decision".[49] In addition, once the AER has published its draft determination, it is required to invite stakeholders to a "pre-determination conference". Stakeholders, including the NSPs, may make written submissions on the AER's draft determination within 45 business days of the stakeholder conference.

87. The AER has to publish its final determination not later than two months before the start of the next control period.[50] Thus the AER has a further three and a half months from

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44 For example, for the recent Powerlink determination, the values of beta, gamma, gearing and market risk premium (MRP) came from the AER's 2009 review of WACC parameters, as required under § 6A.6.2(h) of the Rules.

45 Section 6A.10.1(a).

46 Section 6A.11.1(a).

47 Section 6A.11.2(a).

48 Section 6A.12.2(a).

49 Section 6A.12.3(b).

50 Section 6A.13.3.

receiving the revised proposal (but less than three and a half months from receiving written submissions on its draft decision, which can include written submissions from the NSP).

88. In the recent Powerlink determination, for example, the proposal was submitted in May 2011, a draft decision was published in November 2011, a revised proposal was submitted in January 2012, and the final determination was published in April 2012.

Use of Consultants

89. AER typically engages technical consultants to review the NSP's capex/opex forecasts.[51] In addition, the AER may commission advice on specific topics: for example, for the Victorian DNSP review, the AER commissioned forecasts of wage rate increases.[52]

Interaction with Stakeholders During the Review Process

90. The AER has a formal process of consultation with stakeholders. In addition to the draft determination, stakeholders are typically able to comment on the AER's "framework and approach", published before the NSPs submit their proposals, as well as on the NSPs' proposals and revised proposals. In addition, the AER holds public forums to present its draft determinations.

91. There is considerable interaction between the AER, its technical advisers, and the NSPs during the determination process. This involves both formal written data requests (the RIN process, described below) and meetings.

92. In addition, there are meetings between the AER and the NSPs at senior level, typically at the time that proposals are made, and shortly after the AER's draft determination. The NSP has the opportunity to present its proposal to the AER Board.

Prudence

93. The prudence of past capex is not at issue for the purposes of calculating the opening asset base, because the Rules require that all actually-incurred capex be rolled in. Nevertheless, the AER does examine the "efficiency" of historical capex,[53] presumably to

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51 See, for example, *Powerlink Revenue Determination, Technical Review: Forecast Capital Expenditure and Service Targets*, AER (September 2011);

52 *Forecast growth in labour costs: update of March 2010 report*, Access Economics (September 2010).

53 See, for example, chapter 2 of *Report – Capital Expenditure Victorian Electricity Distribution Revenue Review Revised Proposals*, Nuttall Consulting (October 2010).

inform its judgement as to the likely efficiency of forecast capex (as it is in any case required to do under the Rules).[54]

3.4 THE SERVICE PROVIDER'S APPLICATION

94. The NSP's proposal includes forecasts of capex and opex. It also submits its views on the other building blocks of the overall revenue requirement, and it provides information on actually-incurred historical costs.

95. For TNSPs there is an additional "contingent project" mechanism. The TNSP's revenue application may contain a list of contingent projects and associated "triggers" (for example, connecting a new large load). If accepted by the AER in its determination, and if the defined "trigger" event occurs during the control period, the TNSP will submit an updated capex/opex forecast for the project. The AER will then review the updated costs (and the rules for this review are the same as the rules for assessing the overall capex/opex forecasts).

96. The Rules require the AER to set out "submission guidelines" for what information TNSPs have to provide as part of a revenue proposal. The AER's guidelines (published in September 2007) consist of a narrative document and a spreadsheet template for collecting cost (historical and forecast), and a second template for collecting data required for other elements of the determination (e.g., reliability).

97. The guidelines require that forecasts are broken down into major category or programs for opex, and category, asset class and project for capex.[55]

98. The Rules require the AER to assess whether the TNSP's proposal complies with the guidelines. If it does not, the TNSP is required to correct and resubmit it.

99. The TNSPs are also required to provide information to the AER, on an annual basis, which can be used to determine compliance with the current determination, as well "as an input regarding the financial, economic and operational performance of the provider, to inform the AER's decision-making for the making of revenue determinations or other

54 Actual expenditure during the current period is one of the capex/opex "factors".

55 See the templates at http://www.aer.gov.au/content/index.phtml/itemId/715258

regulatory controls to apply in future regulatory control periods".[56] The AER has also issued guidelines, under the Rules, relating to the content of the annual information return.

100. We note that there appear to be no requirements for DNSPs to provide information to the AER in a "template" format on an annual basis. The AER consulted on an annual reporting guideline in 2008,[57] but has not implemented the proposal. AER issues a "Regulatory Information Notice" (RIN) as part of each DNSP determination process, but there is no generic version as there is for transmission.

3.5 RULES FOR HOW THE REGULATOR'S ANALYSIS IS TO BE CONDUCTED

101. In section 2 of our report we discussed in some detail the Rules relevant to the AER's assessment of NSP capex/opex forecasts. While determining the capex/opex allowances requires the AER to exercise judgement, the Rules guide this discretion. The Rules set out "objectives", "criteria" and "factors". The allowances are required to achieve the "objectives", and the AER must use the "criteria" to assess whether they do. The AER has to have regard to the "factors" in deciding whether the allowances achieve the objectives. In the following paragraphs we describe the requirements for DNSP opex, but the requirements for capex and for transmission capex/opex are essentially the same.

102. Section 6.5.6(a) of the NER provides that a DNSP's opex forecast must achieve the opex objectives:

a) meet or manage the expected demand;
b) comply with all applicable regulatory obligations or requirements;
c) maintain the quality, reliability and security of supply;
d) maintain the reliability, safety and security of the distribution system.

103. Section 6.5.6(c) sets out the "opex criteria":

> *the AER must accept the* [DNSP's] *forecast of required operating expenditure… …if the AER is satisfied that the total of the forecast operating expenditure for the regulatory control period reasonably reflects* [the following opex criteria]*:*
>
> a. *the efficient costs of achieving the operating expenditure objectives; and*

56 Section 6A.17.1(d)(3).

57 *Issues paper: Electricity distribution network service providers – Annual information reporting requirements*, AER (August 2008).

> b. *the costs that a prudent operator in the circumstances of the relevant Distribution Network Service Provider would require to achieve the operating expenditure objectives; and*
>
> c. *a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.*

104. The "opex factors", to which the AER must have regard, are set out in section 6.5.6(e):

> a) *the information included in or accompanying the building block proposal;*
>
> b) *submissions received in the course of consulting on the building block proposal;*
>
> c) *analysis undertaken by or for the AER and published before the distribution determination is made in its final form;*
>
> d) *benchmark operating expenditure that would be incurred by an efficient Distribution Network Service Provider over the regulatory control period;*
>
> e) *the actual and expected operating expenditure of the Distribution Network Service Provider during any preceding regulatory control periods;*
>
> f) *the relative prices of operating and capital inputs;*
>
> g) *the substitution possibilities between operating and capital expenditure;*
>
> h) *whether the total labour costs included in the capital and operating expenditure forecasts for the regulatory control period are consistent with the incentives provided by the applicable service target performance incentive scheme in respect of the regulatory control period.*

3.6 ANALYTICAL TOOLS USED BY THE REGULATOR

105. The AER commissions advice from technical consultants, and carries out its own analysis. AER has developed a range of different tools over time in response to the issues that have arisen in different determinations. For example, it has developed a "repex" (replacement capex) model,[58] which allows AER to test the relationship between a replacement capex program and the age profile of existing assets. Other tools are being developed.

106. AER and its consultants have employed various benchmarking metrics, although the high-level nature of these metrics, and the need to take into account the circumstances of individual businesses, means that the benchmarks are used as a guide to inform AER judgement, rather than anything more determinative.

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58 See, for example, *Victorian Draft Distribution Determination – Draft Decision*, AER (June 2010), p. 338.

107. For the TNSPs, AER and its consultants tend to examine forecast capex on a project-by-project basis. For the DNSPs a sampling approach tends to be used.

108. AER examines the reasonableness of the NSPs' planning processes, as well as the forecasts that are the outcomes of those processes. For example, in the Victorian distribution determination, the AER said: "Nuttall Consulting undertook a high level review of the Victorian DNSPs' planning processes and methodologies used to determine their forecasts. It also undertook a more detailed analysis of specific projects for each business. In undertaking these two review processes Nuttall Consulting has made recommendations on the reasonableness of the proposed reinforcement expenditure forecasts for each Victorian DNSP".[59]

109. The AER and its consultants have used a range of analytical tools to assess the reasonableness of NSP capex/opex forecasts. In the following paragraphs we give some examples of analysis the AER and its consultants undertook in the Powerlink determination.

110. In the Powerlink determination,[60] the AER adjusted the TNSP's capex proposal because:

- the AER did not accept the TNSP's demand forecast;
- the AER considered that certain proposed upgrades would not be required during the control period, so determined that they should be reclassified as contingent projects;
- the AER applied a top-down efficiency adjustment, because the Powerlink capex program did not include a formal performance improvement program, which other utilities had used to improve efficiency.

111. The largest adjustment resulted from the AER's rejection of the demand forecast. It did so because of concerns over the model that Powerlink had used, as well as over inputs to the model. The AER engaged technical consultants to develop an alternative demand forecast. Since, after running various sensitivity analyses, the consultant's model produced forecasts materially below the Powerlink forecast, the AER rejected the TNSP's forecast.

112. In addition to reviewing the demand forecast, the AER and its consultants also assessed the capex forecast using "a mix of top down and bottom up approaches".[61] The

59 *Id*., p. 316.

60 See *Powerlink Transmission Determination, Final Decision*, AER (April 2012).

61 *Id*., p. 106.

capex efficiency adjustment was based on a recommendation from the AER's consultants on the basis of their industry experience, as to the efficiency gains that might be expected from implementing a formal process to improve efficiency.[62]

113. On opex, the AER (and NSPs) typically take a base-step-trend approach, whereby the opex forecast is developed from a recent year for which actual costs are available. The first step is to consider whether costs in the base year are efficient. Then adjustments are made for any new costs, for example flowing from new regulatory obligations. Finally a trend is applied to take account of factors such as scale growth, inflationary pressures, and efficiency improvements.

114. For Powerlink, the AER determined that the base year opex was efficient, on the basis of benchmarking the costs against those of other TNSPs.[63] However, the AER rejected Powerlink's forecast increase in labour costs, and substituted an alternative wage inflation forecast. During the review process, new information (including a collective bargaining agreement agreed by Powerlink staff) became available which suggested that Powerlink's forecast was too high. The AER also disallowed certain network support costs because it considered that Powerlink had presented insufficient information to justify the need for these costs (against the relevant criteria).[64]

3.7 COMMENTARY ON THE APPROACH

115. The AER has had some difficulty with unit costs—it had been hoping that technical consultants would have been able to provide it with better information, but has generally found this difficult. The knowledge base amount technical consultants in the market appears to be insufficient. AER has also experienced difficulty in obtaining advice from independent technical consultants, due to potential advisors being conflicted as a result of current or recent work for the NSPs.

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62 "Based on its experience with past transmission reviews and assessments of network service provider costs in various *jurisdictions*, EMCa considers that an efficiency adjustment ought to be applied to Powerlink's proposed *capex*. EMCa recommended a one per cent reduction in forecast capex in the second year of the regulatory control period followed by a two per cent annual reduction thereafter." (*Powerlink Transmission Determination, Draft Decision*, AER (November 2011)).

63 *Powerlink Transmission Determination, Final Decision*, AER (April 2012)., p. 156.

64 *Id*., p. 171.

116. The AER expressed the view that making comparisons across businesses in different states has been hindered by data problems—data was not consistently collected/reported in the different state jurisdictions. However, this is improving over time.

117. The AER is aware of the "menu" approach that Ofgem has used to encourage NSPs to submit unbiased forecasts. However, such an approach would be inconsistent with the current rules.

118. From our review of AER decisions and discussion with AER staff, we note that AER has been active in developing various analytical tools to assist with the task of assessing the capex/opex forecasts put forward by the NSPs.

4. NEW ZEALAND (COMMERCE COMMISSION)

4.1 INTRODUCTION

119. The Commerce Commission is responsible for regulating electricity distribution and electricity transmission, as well as gas pipelines, airports, and other sectors. It is also the general competition authority.[65] In this section of our report we describe how the Commerce Commission regulates the electricity distribution companies, and the electricity transmission monopoly (Transpower). The nature of the industry in New Zealand, and its regulation, is unusual in several respects. First, there are a large number of distributors, many of them rather small. In total, there are 29 distributors (ranging in size from about 4,000 to 700,000 customers).[66] Second, around half of the distributors are "customer owned", and are exempt from price regulation. Third, the approach to regulation has changed significantly over time. Direct regulation of price was only introduced in 2001—before this, the focus was on requiring companies to produce information on their performance and costs.

120. Until the current regime was introduced in 2008, the industry was subject to a "thresholds" approach. Under the thresholds approach, the regulator set price/quality "thresholds" on the basis of historic cost information. The companies were not required to produce forecasts of opex or capex. Only if a company breached the threshold would an investigation of that company's costs have been triggered, potentially culminating in a more traditional revenue/price determination, based on cost forecasts. In the event, the Commerce Commission was never required to set prices in this way for electricity distributors under the prior regime. Transpower's prices under the prior regime were set pursuant to a settlement agreement between Transpower and the Commerce Commission.

121. Primary legislation to introduce the current arrangements was enacted in 2008.[67] The legislation requires that certain aspects of the regulatory framework have to be determined by the regulator and published as statements of approach, which, once determined, will have to be applied in future decisions to set prices. The statements of approach ("Input Methodologies", or "IMs") are in some respects equivalent to the Rules in the NEM. The

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65 See http://www.comcom.govt.nz/

66 Based on the *Information Disclosure Requirements Database*, published by the Commerce Commission.

67 Commerce Amendment Act 2008, which amended the Commerce Act 1986.

regulatory arrangements are currently incomplete because not all of the required IMs have yet been published, and some of those which have are currently subject to appeal.[68]

122. Transpower is subject to "individual price-quality path" regulation (IPP), under which it is required to produce capex/opex forecasts as inputs to a building-blocks type determination.[69] The IMs associated with the IPP have been published and only the cost of capital IM is being appealed.

123. For the electricity distributors, there is a twin-track approach. All non-exempt distributors are subject to "default price-quality path" regulation (DPP). Any distributor can apply for a "customized price-quality path" (CPP) treatment instead. A forecast of capex/opex is required as part of a CPP application. The purpose of the twin-track approach is "to provide a relatively low-cost way of setting price-quality paths for suppliers of regulated goods or services, while allowing the opportunity for individual regulated suppliers to have alternative price-quality paths that better meet their particular circumstances".[70] Thus the DPP approach is designed to be low-cost/light-touch. The full set of IMs for the DPP has not yet been published, so the details of how the DPP will be set are not clear. The legislation requires that the DPP should be of an RPI-X form, with the same X factor for all distributors, based on historic productivity growth.[71] Starting prices are to be set with reference to current and projected profitability of each distributor.[72]

124. The regulator has determined prices for Transpower. However, prices for electricity distributors have not yet been reset under the current framework.

4.2 OVERARCHING REGULATORY FRAMEWORK

125. The overall objective of the regulator is set out in the governing legislation:[73]

> *The purpose of this* [legislation] *is to promote the long-term benefit of consumers in markets* [where there is little or no competition and little or no likelihood of a substantial increase in competition] *by promoting outcomes*

68 As a result, some of the arrangements which we describe for CPPs applied to electricity distributors may change as a result of on-going appeals.

69 See *Individual Price Quality Path Transpower Reasons Paper* (December 2010).

70 Commerce Act 1986, § 53K.

71 Commerce Act 1986, § 53P(5),(6).

72 Commerce Act 1986, § 53P(3)b.

73 Commerce Act 1986, § 52A(1).

that are consistent with outcomes produced in competitive markets such that suppliers of regulated goods or services–

> a. *have incentives to innovate and to invest, including in replacement, upgraded, and new assets; and*
>
> b. *have incentives to improve efficiency and provide services at a quality that reflects consumer demands; and*
>
> c. *share with consumers the benefits of efficiency gains in the supply of the regulated goods or services, including through lower prices; and*
>
> d. *are limited in their ability to extract excessive profits.*

4.3 THE PRICE DETERMINATION PROCESS

126. Certain information is required as part of a CPP application, and the regulator can reject the application as incomplete if the information is not provided. In addition, the regulator has broad information-gathering powers to collect additional information.[74]

127. While the DPP reset will occur every five years, distributors are allowed to request the CPP alternative at any time (apart from in the last year of the DPP). Once an application for a CPP is received, the regulator has a limited period of time to determine the outcome: if the proposal is complete (i.e., contains all of the information specified in the IMs), the regulator has 150 working days to determine the outcome.[75] The only exception is that the regulator is not required to determine more than four CPP requests in a given year, and may defer consideration of some requests if more than four are received.

128. The cost of capital for the DPP is determined prior to the start of each DPP period. The cost of capital that would apply if an NSP requests a switch to the CPP approach will be determined annually (i.e., the regulator publishes the CPP cost of capital annually, and the most recent cost of capital decision will be used for any business that switches to the CPP in the subsequent 12 months).[76]

129. During the Transpower determination, there was frequent contact between the NSP, the technical consultants and the regulator. This encompassed both formal written "information requests" and more informal meetings to review the Transpower approach. In addition, there was some senior-level contact between the regulator and Transpower.

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[74] *Id.*, § 53ZD.

[75] Commerce Act 1986, § 53T.

4.4 THE SERVICE PROVIDER'S APPLICATION

130. The distribution businesses are required to consult with customers prior to making a CPP application. Distributors have broad discretion: the requirement is that customers have adequate notice, and that the distributor inform customers of the likely impact on its revenue and service quality if the CPP application were to be approved.[77] Consumers have a right to appeal the regulator's decisions on a CPP. "Customer-owned" distributors are exempt from price controls, presumably because customers can directly influence the prices paid (and quality received) through voting rights.

131. All distributors are required to produce "asset management plans", and distributors use the plans as a way of communicating with and eliciting feedback from customers, for example on whether quality performance is adequate.[78]

132. In addition to showing that the cost forecasts are justified, distributors will also be expected to show that they have the capacity to deliver the forecast expenditure.[79]

133. The distributors are required to report historical expenditures, and this information has to be audited. However, in relation to expenditure forecasts, distributors will also be obliged to "certify" and to "verify" that the forecasts are reasonable.[80] "Certify" means that directors of the distributor have to attest that the forecasts are based on reasonable assumptions. "Verify" means that the distributor will have to submit, as part of its CPP application, a report from an independent expert stating that the forecasts are reasonable:

> *An expert opinion is likely to be of most value where judgement is required as to the reasonableness of the assumptions or practice used in developing the information (e.g. the methods used to develop opex forecasts), or where it is necessary to draw conclusions from that information (e.g. its efficiency or prudency). Expert opinion would be of particular value in the assessment of information that is critical to the Commission's decision-making, including forecasts of opex, capex and demand. The Commission will, therefore, require suppliers to engage an independent verifier to provide an expert opinion on*

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76 Since the term of the CPP can be 3, 4 or 5 years, the regulator will publish a 3, 4 and 5 year cost of capital annually. Once a business has switched to a CPP, the cost of capital is not updated during the term of the control.

77 *EDB GPB Input Methodologies – Reasons Paper* (December 2010), ¶ 9.6.19.

78 See, for example, *Wellington Electricity 10 Year Asset Management Plan*, p. 76.

79 *Id.*, ¶ 9.5.12.

80 *Id.*, § 9.6.

certain components of its proposal, prior to submitting their proposal to the Commission.[81]

4.5 RULES FOR HOW THE REGULATOR'S ANALYSIS IS TO BE CONDUCTED

134. In broad terms, the *methodology* that the regulator will follow for CPP applications (and the IPP process for Transpower) is specified in advance as the IMs are determined. In principle, once the IMs are determined, the methods for determining the building blocks of the revenue requirement are set and will be common to all CPP applications. For the cost of capital, not only is the methodology determined in advance, but also the cost of capital itself is determined in a separate process from the CPP application.

135. For electricity distributors, the IM does not provide much prescription on how capex/opex forecasts are to be assessed as part of a CPP application. The criterion for the assessment, set out in the IM, is:

> *Whether proposed capex and opex reflects the efficient costs that a prudent regulated supplier would require to: meet or manage the expected demand for the relevant services, at appropriate service standards, during the forthcoming CPP regulatory period and over the longer term; and comply with applicable regulatory obligations associated with the services.*[82]

136. The regulator has said that a top-down approach will be applied:

> *It is therefore necessary for the Commission to obtain assurance that all proposed expenditure is appropriate. This does not mean that the Commission will undertake a detailed assessment of the supplier's entire expenditure programme. The Commission considers that its role in assessing CPP expenditure forecasts should be analogous to that of the supplier's Board, and a similar level of information is appropriate. The top-down approach allows the Commission to focus on gaining assurance that applicants are operating well-run, prudent businesses that deliver services efficiently.*[83]

137. Although a top-down approach has been specified, the regulator has also said that some project-level detail must be provided:

> *Although the Commission must be able to gain assurance on the entire expenditure programme, the concept of materiality is important to the information requirements to promote a cost-effective approach. The requirements place a greater emphasis, and require more detailed supporting*

81 *Id.*, ¶¶ 9.6.11-12.

82 *EDB GBP Input Methodologies – Reasons Paper* (December 2010), ¶ 9.4.1.d.

83 *Id.*, ¶ 9.5.11.

information, on material aspects of the proposal… …Detailed information must be provided if a project or programme is: one of the five largest opex projects or programmes by total expenditure; one of the five largest capex projects or programmes by total expenditure; or one of ten additional projects or programmes selected by the verifier [see below] *based on preset selection criteria that relate to the business-specific key drivers of the proposal.*[84]

4.6 ANALYTICAL TOOLS USED BY THE REGULATOR

138. The Commerce Commission has had limited experience of assessing capex/opex forecasts. It has not yet completed a DNSP determination.

139. The regulator has completed one determination for Transpower, the TNSP (although that determination was carried out before the relevant IM was finalised). In that case, the Commerce Commission used engineering consultants to assess Transpower's opex and capex forecasts.[85]

140. The consultants were asked to spend about 5 months reviewing the Transpower forecasts, historical data, and internal processes and capacity. The consultants described their role as follows:

> *Geoff Brown & Associate Ltd (GBA) has been engaged by the Commission to review the Expenditure Proposal and provide an objective and independent assessment of the reasonableness of the forecast opex and minor capex taking into account Transpower's operating conditions and the Commission's regulatory framework… … The review has primarily taken the form of a desk-top study of Transpower's Expenditure Proposal and its supporting documents. However the during the course of the review we had extensive discussions with Transpower's management and staff and this has provided an opportunity to better understand the environment in which Transpower operates and the challenges it faces. We also formally asked Transpower a large number of questions related to different aspects of its Expenditure Proposal and we have relied on the written responses to these questions in preparing this report.*[86]

141. The consultants reviewed Transpower's internal governance processes and its cost forecasting approach, and also conducted top-down modelling of opex and high-level benchmarking analysis. On capex, the consultants focused on relating the age and condition of the asset stock to the increase in forecast over historic capex. The main concern

[84] *Id.*, ¶¶ 9.5.14-15.

[85] See *Review of Transpower's Operating and Capital Expenditure for 2012-15*, Geoff Brown and Associates (June 2011).

[86] *Id.*, p. 5.

identified in the review was over the need to reduce the backlog of asset renewals, through a significant increase in capex, in order to obtain the forecast reduction in opex spend over historical levels.[87]

4.7 COMMENTARY ON THE APPROACH

142. We note that the current New Zealand framework is new, and in some respects yet to be finalised. The provisions for determining DNSP revenues have yet to be put into practice.

143. The NSPs are required to obtain third-party verification that their capex/opex forecasts are reasonable. An independent technical consultant is required to review the forecasts, and the underlying methodologies and assumptions, and to state whether or not they are reasonable. This is an interesting approach which we have not seen used elsewhere, and which seems potentially beneficial.

144. The design of the framework is such that, during a CPP determination, the capex/opex forecasts will be the focus of the determination. The other building blocks will either have been determined already or will be determined by applying the decided methodology, with relatively little scope for the exercise of judgement. In particular, the WACC is determined separately from and outside the CPP process.

145. In some respects, the New Zealand framework is similar to the NEM framework (with the New Zealand IMs broadly equivalent to the Rules in the NEM). In relation to capex/opex forecasts, there is significantly less prescription in New Zealand, both relative to the Rules and relative to the IMs on other topics (e.g., the WACC).

146. The design of the New Zealand approach may partly be influenced by the need to regulate a relatively large number of rather small NSPs.

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87 See *Transpower minor capex and opex allowances, and quality standards for RCP1 – Final decisions*, Commerce Commission (August 2011).

5. NEW SOUTH WALES (IPART)

5.1 INTRODUCTION

147. IPART (the Independent Pricing and Regulatory Tribunal in New South Wales) is responsible for setting the maximum prices to be charged by certain monopolies, including water and transport. In the energy sector, IPART determines the maximum prices that can be charged for regulated services provided by energy retailers. However, electricity and transmission distribution networks in NSW are regulated by the AER under the NER. Prior to the current regulatory periods, these networks were also regulated by IPART.

148. IPART also has licensing responsibilities. It is responsible for monitoring and overseeing supplier performance and licence compliance, and recommending enforcement or corrective action to the NSW government.

149. For this study we have reviewed how IPART assesses capex/opex forecasts as part of determining maximum prices in the water sector, and we also reviewed the last round of electricity distribution network determinations. We focussed on the current review of Sydney Water, for which a draft determination was published in March 2012,[88] and the review of electricity distribution service providers for the 2004/5 to 2008/9 period.[89]

150. Sydney Water, as well as the electricity distribution networks in NSW, are owned by the NSW government.

5.2 OVERARCHING REGULATORY FRAMEWORK

Water

151. IPART's determination of maximum water prices is governed by the IPART Act.[90] Section 14A of the Act lists some factors that IPART *may* take into account, and section 15 lists factors which IPART *must* take into account. Neither list is exhaustive.

152. Under section 14A, IPART may consider:

a) the government agency's economic cost of production,

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88 *Prices for Sydney Water Corporation's water, sewerage, stormwater drainage and other services—Draft Report*, IPART (March 2012).

89 *NSW Electricity Distribution Pricing 2004/05 to 2008/09 Final Report*, IPART (June 2004).

90 *Independent Pricing and Regulatory Tribunal Act 1992*.

b) past, current or future expenditures in relation to the government monopoly service,

c) charges for other monopoly services provided by the government agency,

d) economic parameters, such as:

   1. discount rates, or
   2. movements in a general price index (such as the Consumer Price Index), whether past or forecast,

e) a rate of return on the assets of the government agency,

f) a valuation of the assets of the government agency,

g) the need to maintain ecologically sustainable development,

h) the need to promote competition in the supply of the service concerned, and

i) considerations of demand management (including levels of demand) and least cost planning.

153. Under section 15, IPART must "have regard to the following matters (in in addition to any other matters the Tribunal considers relevant):

a) the cost of providing the services concerned,

b) the protection of consumers from abuses of monopoly power in terms of prices, pricing policies and standard of services,

c) the appropriate rate of return on public sector assets, including appropriate payment of dividends to the Government for the benefit of the people of New South Wales,

d) the effect on general price inflation over the medium term,

e) the need for greater efficiency in the supply of services so as to reduce costs for the benefit of consumers and taxpayers,

f) the need to maintain ecologically sustainable development…

g) the impact on pricing policies of borrowing, capital and dividend requirements of the government agency concerned and, in particular, the impact of any need to renew or increase relevant assets,

h) the impact on pricing policies of any arrangements that the government agency concerned has entered into for the exercise of its functions by some other person or body,

i) the need to promote competition in the supply of the services concerned,

j) considerations of demand management (including levels of demand) and least cost planning,

k) the social impact of the determinations and recommendations,

l) standards of quality, reliability and safety of the services concerned (whether those standards are specified by legislation, agreement or otherwise)."

154. None of the IPART Act requirements bear directly on how IPART is to assess cost forecasts submitted by the water service provider.

Electricity

155. When IPART determined the maximum prices to be charged by the electricity distribution network operators, it did so under the National Electricity Code (the Code). The Code does not directly address how the regulator is to assess capex/opex forecasts, but does contain several provisions which guide the regulator's judgement (in the quoted parts of the code which follow, we highlight in bold sections which appear to us to be particularly relevant). Section 6.10.5d requires that:

> *In setting a separate regulatory cap to be applied to each Network Owner… …the Jurisdictional Regulator must take into account each Distribution Network Owner's revenue requirements during the regulatory control period, having regard for:*
>
> a. *the demand growth which the Distribution Network Owner is expected to service using any appropriate measure including but not limited to:*
>   1. *energy consumption…*
>   2. *demand…*
>   3. *numbers of Distribution Customers…*
>   4. *length of the distribution network;*
>
> b. *the service standards…*
>
> c. *price stability;*
>
> d. ***the Jurisdictional Regulator's reasonable judgment of the potential for efficiency gains to be realised by the Network Owner in expected operating, maintenance and capital costs****, taking into account the expected demand growth and service standards referred to in clauses 6.10.5(d)(1) and (2);*
>
> e. *the Distribution Network Owner's weighted average cost of capital …*
>
> …

156. In addition, section 6.10.2 of the Code describes the objectives of the regulatory regime:

> *The distribution service pricing regulatory regime to be administered under Part D of the Code must seek to achieve the following outcomes:*
>
> a) *an efficient and cost-effective regulatory environment;*
>
> b) *an incentive-based regulatory regime which:*
>
> 1. ***provides an equitable allocation between Distribution Network Users and Distribution Network Owners of efficiency gains reasonably expected by the Jurisdictional Regulators to be achievable by the Distribution Network Owners;***
> 2. *provides for, on a prospective basis, a sustainable commercial revenue stream which includes a fair and reasonable rate of return to Distribution*

Network Owners on efficient investment, given efficient operating and maintenance practices of the Distribution Network Owners;

...

c) prevention of monopoly rent extraction by Network Owners;

d) an environment which fosters an efficient level of investment within the distribution sector, and upstream and downstream of the distribution sector;

e) an environment which fosters efficient operating and maintenance practices within the distribution sector;

…

i. ***reasonable regulatory accountability through transparency and public disclosure of regulatory processes and the basis of regulatory decisions****;*

j. reasonable certainty and consistency over time of the outcomes of regulatory processes, recognising the adaptive capacities of Code Participants in the provision and use of distribution network assets;

k. ***reasonable and well defined regulatory discretion which permits an acceptable balancing of the interests of Distribution Network Owners, Distribution Network Users and the public interest****.*

157. Thus there are a number of Code provisions which relate to how IPART should review the service provider's cost forecasts, although none are prescriptive.

158. As we document below, IPART's approach to reviewing the service provider's cost forecasts in the two sectors was very similar.

5.3 THE PRICE DETERMINATION PROCESS

Form and Timing

159. IPART uses a "building blocks" approach to determining the required revenue in the up-coming period. All of the building blocks, including the cost of capital, are considered together within the same process.

160. There are no formal requirements as to timing of IPART's decision making processes. The Sydney Water draft determination was published in March 2012, and a final decision is expected in June 2012 (to set water prices for July 2012). IPART published an issues paper in June 2011, and the formal application from Sydney Water was received in September 2011. The process is thus 12 months overall, and nine months from the receipt of the application.

161. The electricity determination setting prices for July 2004 was published in June 2004, and the DNSP submissions were published in April 2003. The first IPART issues paper was

published in November 2002, and IPART also began requesting information from the DNSPs at that time.[91] Thus the electricity process took 19 months overall, and 14 months from the submission of formal applications by the DNSPs.

162. IPART's process begins with an "issues paper", to which the service provider's "application" is a response. In this way, IPART is able to signal the type of information that the service provider should submit.

Use of Consultants

163. IPART commissioned technical advice from engineering consultants on the proposed capex/opex allowances in both the Sydney Water[92] and electricity distribution[93] reviews. In both cases, the consultants were asked to review the prudence of past expenditure and the efficiency of the company's forecasts.

Interaction with Stakeholders During the Review Process

164. During the review process, IPART has formal consultation on an issues paper, and a draft decision, and the service providers and other stakeholders respond to these consultations.

165. IPART and its technical consultants correspond with the service providers in order to obtain additional information, and the technical consultants conduct interviews. IPART's preference is for as much of the interaction as possible to be on a written basis, because this aids transparency.

166. IPART holds regular meetings at senior level with service providers, including Sydney Water. However, these meetings do not take place during the determination process. Because it has other roles in addition to determining maximum prices (such as licensing), IPART collects information from water service providers on a regular basis. This information is helpful because it helps IPART understand the service provider's business, including drivers of cost, and it means that IPART has a good picture of historical spending.

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91 See timetable as set out in *Regulatory arrangements for the NSW Distribution Network Service Providers from 2004, Issues paper*, IPART (November 2002).

92 See *Final Report Detailed Review of Sydney Water Corporation's Operating and Capital Expenditure*, WS Atkins in association with Cardno (November 2011).

93 See *Review of Capital and Operating Expenditure of the NSW Electricity Distribution Network Service Providers – Final Report*, Meritec (September 2003).

Prudence

167. Both for water and electricity distribution service providers, IPART reviews the prudence of historical investment. There is no automatic roll-in of investment into the opening asset base for the new control period.

5.4 THE SERVICE PROVIDER'S APPLICATION

168. The service provider submits forecasts of capex and opex. It also submits its views on the other building blocks of the overall revenue requirement, and it provides information on actually-incurred historical costs.

169. There are no specific requirements on the precise form of Sydney Water's forecast. However, the forecast comes in response to an IPART issues paper.

170. The forecasts are broken down into major elements or programs for opex, and major projects for capex. As part of the opex forecast, Sydney Water identified "efficiency savings", which represent elements of opex that are forecast to decline over time relative to the current level. The capex forecast includes a discussion of the major drivers (growth in customer numbers).

5.5 RULES FOR HOW THE REGULATOR'S ANALYSIS IS TO BE CONDUCTED

171. Section 15 of the IPART Act gives no guidance to IPART on how the service provider's cost forecasts should be assessed.

172. In electricity there were no prescriptions in the National Electricity Code, but several provisions that seem to have been generally relevant to the assessment of the service providers' forecasts. IPART was required "to have regard for [its] reasonable judgment of the potential for efficiency gains to be realised by the Network Owner in expected operating, maintenance and capital costs".[94] In addition, an objective of the Code was that it "provides an equitable allocation between Distribution Network Users and Distribution Network Owners of efficiency gains reasonably expected by [IPART] to be achievable by the Distribution Network Owners".[95] Another objective was "reasonable and well defined

[94] Section 6.10.5d(4).

[95] Section 6.10.2b(1).

regulatory discretion which permits an acceptable balancing of the interests of Distribution Network Owners, Distribution Network Users and the public interest".[96]

5.6 ANALYTICAL TOOLS USED BY THE REGULATOR

173. IPART both commissions technical advice from engineering consultants and conducts its own analysis. There is no restriction on the type of analysis that can be undertaken. In practice, IPART and its consultants have used a range of tools, as described in the consultants' reports and IPART's decisions.

174. IPART examines historical expenditure relative to the authorized amounts in addition to capex/opex forecasts.

175. A sampling approach was used for Sydney Water's capex program. The consultants were asked to review 10% of projects costing more than $5m (for both the projects in the prior period and forecast projects).

176. IPART examines both the forecasts themselves and the service providers' planning processes that were used to produce the forecasts.

177. IPART's consultants undertook some benchmarking of Sydney Water relative to other water service providers. Inevitably, however, the final recommendations of the engineering consultants were based in part on professional judgement.[97]

178. When it had responsibility for regulating distribution network service providers, IPART undertook detailed statistical benchmarking analyses aimed at estimating the efficiency of the NSW service providers relative to other distributors in Australia and elsewhere.[98] Some of this analysis involved total factor productivity assessment, but not for the purpose of setting rates or an "X-factor". IPART undertook this research in the run up to the 1999 price determination, but it was not used in the 2004 determination.

5.7 COMMENTARY ON THE APPROACH

179. In determining the maximum prices for Sydney Water, IPART suggested that the interaction they have with the company by virtue of IPART's licensing function was

96 Section 6.10.2k.

97 For example: "On the basis of what we have seen, our view of prudent expenditure is a judgement which takes into account the decision making process and the impact of those decisions. We have assumed that 15% of expenditure above the 2008 Determination was not prudent." (WS Atkins report, p. 137).

98 See *Pricing for Electricity Networks and Retail Supply Volume 1*, IPART (June 1999).

particularly helpful. It meant that IPART already had access to detailed information about the company's operational and financial performance on an on-going basis.

180. IPART appears to maintain a constructive relationship with the entities it regulates, which facilitates information disclosure. It was also suggested to us that some incentives for information disclosure and efficiency derive from the risk that IPART may (and does) disallow expenditures when warranted.

181. There is an appeals process for IPART's decisions, but it has not been used to date, perhaps because the entities being regulated are state-owned enterprises.

6. WESTERN AUSTRALIA (ERA)

6.1 INTRODUCTION

182. The Energy Regulatory Authority (ERA) regulates the monopoly aspects of the gas, electricity, and rail industries in Western Australia (WA), and it licenses the suppliers of gas, electricity and water services.

183. The ERA regulates the business of electricity transmission and distribution ("network services") in WA under the terms of the *Electricity Network Access Code of 2004* (the Code). The overall objective of the Code is to promote "the economically efficient investment in, and operation and use of, networks and services of networks in Western Australia in order to promote competition in markets upstream and downstream of the networks".[99] ERA regulates the prices charged for gas transmission and distribution under the terms of the *National Gas Access (WA) Act 2009* (NGA) which implements the *National Gas Law* (NGL) in WA and gives effect to the *National Gas Rules* for gas access regulation in WA.

184. For this study, we have reviewed how the ERA assesses capex and opex forecasts in the electricity transmission and distribution business, and as an example of this process we focused on the most recent access arrangement review of Western Power as described in *Final Decision on Proposed Revisions of the Access Arrangement for the Southwest Interconnected Network,* submitted by Western Power, 4 December 2009.

6.2 OVERARCHING REGULATORY FRAMEWORK

185. The Code objective is set out in section 2.1:

> *2.1 The objective of this Code ("Code objective") is to promote the economically efficient:*
>
> *a. investment in; and*
>
> *b. operation of and use of,*
>
> *networks and services of networks in Western Australia in order to promote competition in markets upstream and downstream of the networks.*

[99] Electricity Networks Access Code of 2004, p.11.

186. There are some overall constraints placed on the ERA's assessment criteria for approving an access arrangement found in section 4 of the Code, and in particular section 4.28 (b):

> *to avoid doubt, if the Authority considers that the Code objective and the requirements set out in Chapter 5 (and Chapter 9, if applicable) are satisfied****, it must not refuse to approve the proposed access arrangement on the ground that another form of access arrangement might better or more effectively satisfy the Code objective and the requirements*** *set out in Chapter 5 (and Chapter 9, if applicable).*
>
> *{Note:* ***The effect of section 4.28 is to make the Authority's decision in relation to a proposed access arrangement a —pass or fail assessment. The intention is that, if a proposed access arrangement meets the Code objective and the requirements set out in Chapter 5 (and Chapter 9, if applicable), the Authority should not refuse to approve it simply because the Authority considers that some other form of access arrangement might be even better, or more effective, at meeting the Code objective and the requirements*** *set out in Chapter 5 (and Chapter 9, if applicable).}*

187. The specific requirements and objectives for a price control are set out in sections 6.1 to 6.5 of the Code:

> *6.1 Subject to section 6.3, an access arrangement may contain any form of price control provided it meets the objectives set out in section 6.4 and otherwise complies with this chapter 6.*
>
> *6.2 Without limiting the forms of price control that may be adopted, price control may set target revenue:*
>
> *a. by reference to the service provider's approved total costs; or*
>
> *b. by setting tariffs with reference to:*
>
> *1. tariffs in previous access arrangement periods; and*
>
> *2. changes to costs and productivity growth in the electricity industry;*
>
> *or*
>
> *c. using a combination of the methods described in sections 6.2(a) and 6.2(b).*
>
> *6.3 The first access arrangement must contain the form of price control described in section 6.2(a).*
>
> *6.4 The price control in an access arrangement must have the objectives of:*
>
> *a. giving the service provider an opportunity to earn revenue ("target revenue") for the access arrangement period from the provision of covered services as follows:*
>
> *1.* ***an amount that meets the forward-looking and efficient costs of providing covered services, including a return on investment commensurate with the commercial risks involved;***

plus:

2. *for access arrangements other than the first access arrangement, an amount in excess of the revenue referred to in section 6.4(a)(i), to the extent necessary to reward the service provider for efficiency gains and innovation beyond the efficiency and innovation benchmarks in a previous access arrangement;*

plus:

3. *an amount (if any) determined under section 6.6* [adjustments for unforeseen events]*;*

plus:

4. *an amount (if any) determined under section 6.9* [adjustments for technical rule changes]*;*

plus:

5. *an amount (if any) determined under an investment adjustment mechanism (see sections 6.13 to 6.18);*

plus:

6. *an amount (if any) determined under a service standards adjustment mechanism (see sections 6.29 to 6.32);*

plus –

7. *an amount (if any) determined under section 6.37A* [tariff equalisation contributions]*;*

and

b. *enabling a user to predict the likely annual changes in target revenue during the access arrangement period; and*

c. *avoiding price shocks (that is, sudden material tariff adjustments between succeeding years).*

6.5 The amount determined in seeking to achieve the objective specified in section 6.4(a)(i) is a target, not a ceiling or a floor.

6.3 THE PRICE DETERMINATION PROCESS

188. While the Code permits variation in the form of the price control that the ERA may employ, the practice of the ERA has been to permit network service providers to use the "building blocks" and RAB "roll-forward" approach similar to the one employed by the AER for the NEM for the purpose of establishing a revenue cap access arrangement.

189. The access arrangement control period is a minimum of three years (and up to five years in practice, primarily determined at the discretion of the service provider).

190. The Code contains criteria for the evaluation of non-capital costs (opex) and capital costs, in sections 6.40–6.42 and 6.49–6.55, respectively. The criteria for including non-

capital costs in the approved total costs for the network services provider are those "which would be incurred by a *service provider efficiently minimising costs*".[100] For capital costs, the Code permits a RAB (capital base) that is rolled forward from the valuation made at the beginning of the initial access arrangement, which can be based on Optimised Deprival Value (ODV) or Depreciated Optimised Replacement Cost (DORC) methods (or by Ministerial direction).[101] The roll-forward requires the ERA to evaluate the prudence of the investments made in the prior access arrangement period on an ex post basis.

191. The Code permits new facilities investment that is forecast to be required over the term of the access arrangement to be included in the capital base if it satisfies the "New Facilities Investment Test". The New Facilities Investment Test is satisfied under Section 6.52 of the Code if:

> a. *the* ***new facilities investment*** *does not exceed the amount that would be invested by a* ***service provider efficiently minimising costs****, having regard, without limitation, to:*
>
> > 1. *whether the* ***new facility*** *exhibits economies of scale or scope and the increments in which capacity can be added; and*
> >
> > 2. *whether the lowest sustainable cost of providing the covered services forecast to be sold over a reasonable period may require the installation of a* ***new facility*** *with capacity sufficient to meet the forecast sales;*
>
> *and*
>
> b. *one or more of the following conditions is satisfied:*
>
> > 1. *either:*
> >
> > > A. *the* ***anticipated incremental revenue*** *for the* ***new facility*** *is expected to at least recover the* ***new facilities investment****; or*
> > >
> > > B. *if a* ***modified test*** *has been approved under section 6.53 and the* ***new facilities investment*** *is below the* ***test application threshold****—the* ***modified test*** *is satisfied;*
> > >
> > > *or*
> > >
> > > C. *the* ***new facility*** *provides a* ***net benefit*** *in the* ***covered network*** *over a reasonable period of time that justifies the approval of higher* ***reference tariffs****;*
> >
> > *or*
> >
> > 2. *the* ***new facility*** *is necessary to maintain the safety or reliability of the* ***covered network*** *or its ability to provide contracted* ***covered services****.*

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[100] *Id*., § 6.40.

[101] Re-valuations of the capital base are also permitted at the start of subsequent access arrangements using ODV or DORC.

192. In addition to the application of the New Facilities Investment Test for the purpose of determining whether, at the outset of the access arrangement, a forecast of capex may be added to the capital base on a forward looking basis, there is a mechanism for the service provider to request approval of forecast capital investment costs (or opex) at any time during the access arrangement period. Once approved, the prudence of the investment cannot be reviewed (except for overspend amounts) at the end of the term of the access arrangement.

193. There is also an "investment adjustment mechanism" for truing up for investment driven by demand or safety considerations during the access arrangement period (both under- and over-spend is trued up).

Use of Consultants

194. The ERA makes regular use of technical engineering consultants for both the detailed evaluation of historical costs and forecasts, and for the evaluation of the "governance" process for project management and cost control by the service provider.

195. In the case of the Western Power access arrangement, the ERA engaged Wilson & Cook Co. to evaluate the detailed cost forecasts and historical capex/opex. In that evaluation the consultant noted that the objective of its evaluation was to:

- assess the efficiency of the network businesses' expenditure estimates and asset management policies in terms of their match with international practice,
- take into account a natural level of trade-off between capex and opex,
- be satisfied that the proposed expenditure, projects and programmes are consistent with maintaining, or where necessary varying, standards and service delivery capacity,
- form an overall strategic view of whether the businesses' proposed levels of expenditure are reasonable and efficient; that is, whether they represent efficient levels for the defined security of supply and service standards or,
- if required, be satisfied that they reflect a transitional path from the present level of expenditure to a more efficient level.

  "We thus took into account past levels of spending from the standpoint of whether it ought to influence future expenditure levels and other expert opinion on the projected expenditure or related matters that was made available to us".[102]

[102] Wilson Cook & Co., p. 7.

196. The consultant engaged to review the governance process of Western Power was Geoff Brown and Associates. The consultant described its role as:

> *undertaking a review of a cross-section of representative projects and programs to assess:*

- the *integration and consistency of procedures and policies across projects;*
- *the adequacy of internal control structures or specific internal controls, to ensure*
- *due regard for effectiveness and efficiency;*
- *the extent to which activities have been effective in achieving organizational objectives;*
- *whether projects take place on a timely basis, with minimum network disruption and at least cost;*
- *the effectiveness of internal audit processes;*
- *past and current practices relating to planning future work programs and strategies; and*
- *long term network development strategies.*

> *The primary purpose of the review was to assist the Authority understand the extent to which it can rely on Western Power's governance arrangements to determine whether Western Power's access arrangement forward work program and forecasts of capital and operating expenditure are prudent. While this objective as stated is focused on forecast expenditure, the assessment of the effectiveness of Western Power's governance arrangements has, of necessity, required a review of the governance and management of projects and programs1 undertaken during the current regulatory period from 1 July 2006 to 30 June 2009 (AA1).*[103]

197. The interaction between the ERA's technical consultants and the service provider's staff are considered to be satisfactory, and processes exist for the technical consultant to obtain the detailed information that it requires for its evaluation.

6.4 The Service Provider's Application

198. In WA the service provider initiates the access arrangement process with an application. In electricity the ERA's process for considering the application is the "propose/respond" model as laid out in section 4 of the Code. In response to the application, the ERA may either accept it unmodified, or propose an alternative draft revised access arrangement. The service provider responds to this proposed revision, and on

[103] Geoff Brown & Associates, *Review of Expenditure Governance; Western Power*, Economic Regulation Authority, 14 July 2009, p. 1.

the basis of the revised proposal the ERA either accepts it or it issues a final further-revised access arrangement which becomes the basis for the price control.

199. There is an appeals process for the final determination. In electricity the appeal is to the Electricity Review Board, and ultimately to the WA Supreme Court. In gas the appeal is to the Australian Competition Tribunal (ACT). No appeals have been made in respect of electricity determinations as yet. Appeals of ERA decisions in gas have been made to the ACT.

200. The Code sets out time constraints for the various elements of the review process, which total to approximately nine months from receipt of application to decision. There is provision for the extension of the time limitations for good cause that could result in an approximate doubling of the time for review if fully exercised.

6.5 Rules for How the Regulator's Analysis is to be Conducted

201. Other than the requirements for *ex ante* and *ex post* review of capex/opex history and forecasts, the Code is not prescriptive as to the methods that the ERA must use to make its evaluation.

202. No distinction is made between transmission and distribution for the purposes of capex/opex evaluation.

203. The ERA does not prescribe the methods which its technical consultants employ to evaluate the capex/opex history and forecasts, and instead relies on their expertise to determine the best approach. That said, the ERA has expressed some frustration with the local knowledge and availability of consultants to use for this purpose that are not compromised due to prior engagements on behalf of service providers.

204. While the ERA relies on the evaluations of the technical consultants, it conducts its own review of all relevant information before making its final determinations, and has in some cases disagreed with the conclusions of its consultants.

205. The ERA has also expressed frustration with the amount and quality of information it has been able to obtain from service providers, and the cooperation of service providers in the process, particularly in gas. ERA's experience is that the effectiveness of the review depends critically on the relationship with the service provider—if the service provider is reluctant to engage with the regulator, the process of obtaining information relevant to the review of capex/opex forecasts is very frustrating and ineffective.

206. ERA says that a set of consistent chart of accounts with a cost-allocation mapping would be desirable (particularly for gas). The "reasonableness" standard for compliance with information requests gets in the way of accomplishing this if the service provider does not want to provide the data.

207. The ERA's licensing role does not provide helpful access to operational information due to the need to keep the ERA's different processes separated and the use of separate staff for licensing and price control review purposes.

6.6 ANALYTICAL TOOLS USED BY THE REGULATOR

208. The ERA has employed benchmarking methods with respect to the evaluation of opex. In this case of historical capex, it (and its technical consultants) have employed sampling techniques. For example, approximately 30% of historical capex projects are selected for detailed review. To the extent particular problems are uncovered in the sampled projects, further review of the remaining projects may be undertaken. If appropriate, any disallowance associated with the sampled projects may be applied "across the board".

209. In the case of the recent review of the second access arrangement for the South West Interconnected Network, the ERA and its consultants assessed actual opex by benchmarking Western Power against other NSPs. Although Western Power was at the top of the range in this benchmarking, the ERA accepted the costs as a suitable base for the forecasts.[104] The ERA reviewed elements of the opex cost forecasts on a line-by-line basis, and disallowed some costs associated with "semi-discretionary" business support costs because they were insufficiently justified, and an increase in corrective maintenance costs, because the ERA felt that an increase was inconsistent with the significant increase in preventative maintenance that it approved.[105]

210. In the case of forecast capex, the ERA requires robust business cases to be submitted for the projects that make up the forecast. The main issues in respect of capex forecasts were the sensitivity of the capex forecast to demand growth. The ERA required Western Power to prepare a new forecast that took into account the impact of the financial crisis, resulting in a substantial reduction to Western Power's forecast. The ERA also directed

[104] Final Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network, ERA (December 2009), p. 143.

[105] *Id.*, pp. 179-80.

Western Power to remove a 3.5% “overspend contingency” that had been applied to all capex forecasts.

6.7 COMMENTARY

211. There are many aspects of the ERA’s rules and authority with respect to capex/opex allowances under its access arrangement regime that are similar to the AER’s. In particular, the ERA employs the propose/respond process, and the Code requires it to accept the service provider’s proposal if it is adequate to meet the objectives of the Code (i.e., it is a “pass/fail” standard, not a “best or most-efficient” standard). It is not clear that this constraint has made any difference to the ERA’s ability in practice to suggest appropriate modifications to the service providers’ proposals or that it constrains in any way the methods the regulator uses to assess the efficiency of capex/opex forecasts and historical levels.

212. It was clear from our interview with ERA personnel that the working relationship between the regulator and service provider is crucial to the obtaining of high quality information and data for the evaluation of a proposed access arrangement. A breakdown in that relationship may mean that any request for information can be challenged on the grounds of the “reasonableness” of the request, with resulting delays and frustration.

213. We note that, for the second access arrangement for Western Power, the ERA and its consultants reviewed the efficiency of actual capex in the prior period in some detail, and disallowed some of this capex.

214. The reliance on technical consultants is crucial, particularly for state-level regulators who do not have extensive internal resources or expertise. Finding independent consultants with local knowledge and experience has been a challenge.

7. ONTARIO (ONTARIO ENERGY BOARD)

7.1 INTRODUCTION

215. The Ontario Energy Board ("OEB") regulates roughly 80 electric distribution and 6 electric transmission companies in Ontario.[106]

216. The OEB derives its authority and is bound by the Ontario Energy Board Act (1998), Statutory Powers Procedure Act, Electricity Act (1998), and Municipal Franchises Act.[107] In particular, the Ontario Energy Board Act (1998) grants the OEB authority to "specifying methods or techniques to be applied in determining the licensee's rates", "requiring the licensee to maintain specified accounting records, prepare accounts according to specified principles and maintain organizational units or separate accounts for separate businesses in order to prohibit subsidies between separate businesses" and "requiring the licensee to provide, in the manner and form determined by the Board, such information as the Board may require".[108]

217. For this study, we have reviewed how the OEB assesses capex and opex forecasts in determining rates for electric transmission and distribution utilities in the province. Our analysis has been based on reviewing publicly available documents and interviews with personnel at the OEB.

7.2 OVERARCHING REGULATORY FRAMEWORK

218. The OEB's "principal functions is to set 'just and reasonable rates' that utilities may collect from ratepayers for utility services".[109] OEB's mandate also includes protecting the "interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service".[110] As such, OEB tries to balance the interests of consumers with that of the regulated utility. OEB believes "consumers are well served if both the pricing and the

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[106] Only a small fraction of these utilities are investor-owned (e.g., Fortis & Brookfield).

[107] http://www.ontarioenergyboard.ca/OEB/Industry/Media+Room/Publications/OEB+Resource+Guide/Reference+Documents (accessed May 3, 2012)

[108] http://www.e-laws.gov.on.ca/html/statutes/english/elaws_statutes_98o15_e.htm#BK85 (accessed May 3, 2012)

[109] *Energy Sector Regulation – A Brief Overview*, Ontario Energy Board, p. 2

[110] http://www.ontarioenergyboard.ca/OEB/Industry/About+the+OEB/What+We+Do

standard of service being provided are fair and reasonable".[111] The OEB also views the economic efficiency and financial viability of the utility sector as one of the important factors in determining the authorized rates.

219. The OEB is in favour of settlements as "a part of its objective of achieving greater regulatory efficiency and effectiveness".[112]

220. The OEB is obligated by law to hold hearings for setting utility rates, where consumers groups can participate. There are consumer groups such as Vulnerable Energy Consumers Coalition (VECC), Association of Major Power Consumers in Ontario (AMPCO), and Consumers Council of Canada (CCC) that intervene during rate case proceedings. The OEB also allows the interveners to apply for funding which the applicant (utility) is responsible for providing. This allows interveners without financial wherewithal to participate in the process.

7.3 THE PRICE DETERMINATION PROCESS

221. Generally speaking, the current OEB regulatory framework for setting distribution rates entails a price reset every four years.[113] The transmission rates are also rebased every four years. All of the regulated electric utilities (both distribution and transmission) are governed by the same framework and have the same filing and regulatory requirements.

222. OEB's incentive mechanism for electric distributors is "designed to promote efficient utility behaviour yet be flexible enough to accommodate diversity in companies' investment requirements".[114] The IR mechanism is an inflation minus X-factor price-cap, and different X factors can be set for different utilities, using benchmarking to assess relative efficiency. There are true up mechanisms for changes in cost that are outside of control of the utilities but affect their costs (e.g., change in goods and services taxes).

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111 *Energy Sector Regulation – A Brief Overview*, Ontario Energy Board, p. 2.

112 *Settlement Conference Guidelines*, Ontario Energy Board, p. 1.

113 *Staff Discussion Paper on Defining & Measuring Performance of Electricity Transmitters & Distributors, Ontario Energy Board*, EB-2010-0379, November 8, 2011, pp. 9-10.

114 *Id*., pp. 17-20.

223. The price reset which occurs every four years requires a full “cost of service filing”. Since the “test year” is the first year of the new control period, the utilities are required to submit capex/opex forecasts for the current year and the first year of the new control, as well actual costs for the preceding three years.[115] The filing requirements for cost of service are laid out in *Chapter 2 of the Filing Requirements for Transmission and Distribution Applications*. The OEB believes that the onus is on the utilities (applicant) to show that what they have asked for is reasonable. A more detailed description of the filing requirements for capex/opex is provided below.

224. Unlike the building-block approach typically used in Australia, the OEB’s approach is effectively a hybrid for electricity distribution.[116] While the first year of the new control period is assessed on the basis of cost forecasts, costs for the following three years are not assessed using explicit forecasts (except for some elements of capex). Rather, the OEB sets the subsequent path of prices using historical productivity trends.

225. However, in addition to the productivity trend, there is a mechanism whereby a distributor may apply for “incremental capital” investment during the control period.[117] The distributor is eligible for this mechanism if it can show that the need for additional capex (within the control period) is material, necessary and prudent.

Capex

226. For capex, the COS filing requirements states that:[118]

> *The applicant must provide an overall summary of capital expenditures over the past five historical years, the bridge year and the test year, showing capital expenditures, treatment of contributed capital and additions and deductions from Construction Work in Progress (“CWIP”). The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the capital budget in the miscellaneous category.*

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115 *Chapter 2 of the Filing Requirements for Transmission and Distribution Applications*, Ontario Energy Board, June 22, 2011, p. 8.

116 The approach for transmission is based on forecasts, but for only two years (see EB-2008-0272, OEB (May 2009), which set transmission rates for Hydro One for 2009 and 2010).

117 See *Staff Discussion Paper on Defining & Measuring Performance of Electricity Transmitters & Distributors*, OEB (November 2011).

118 *Chapter 2 of the Filing Requirements for Transmission and Distribution Applications*, Ontario Energy Board, June 22, 2011, p. 21.

227. In particular, the document also states that the following capex information is required as part of the COS application: [119]

> a) For projects over the applicable materiality threshold: need, scope, and purpose of project, related customer attachments, volumes and capital costs, as well as any applicable cost-benefit analysis;
>
> *b) Detailed breakdown of starting dates and in-service dates for each project;*
>
> *c) Drivers of capital expenditure increases for the Test year;*
>
> *d) Where a proposed project requires Leave to Construct approval under Section 92 of the OEB Act, with construction commencement in the test year, the applicant must provide a summary of the evidence for that project consistent with the requirements set out in section 4.3, section 4.4 and Chapter 5 of these Filing Requirements;*
>
> *e) Components of Other Capital Expenditures including a reconciliation of all capital components to the Total Capital Budget;*
>
> *f) Written explanation of variances, including that of the last Board approved year as compared to the actual expenditures for that year;*
>
> *g) Capitalization policy and any proposed changes to that policy; and*
>
> *h) For capital projects that have a project life cycle greater than one year, the proposed accounting treatment, including the treatment of cost of funds.*
>
> *i) The applicant must provide a formal asset management plan, if the applicant has such a plan. If not, an explanation as to why the applicant does not have such a plan must be provided. The applicant must also state whether or not it is planning to have one in place in the future.*
>
> *j) In the absence of an asset management plan, the applicant must provide information outlining its approach to the planning and prioritization of capital projects.*
>
> *k) The applicant must also provide, at minimum, a three year forecast of capital expenditures (Test year plus two subsequent years).*
>
> *l) The applicant must also state whether or not it has undertaken any asset condition studies and, if so, copies of such studies must be filed.*

[119] *Id*., pp. 21-22.

Opex

228. The utilities are also required to file a detailed summary of opex as part of the COS application. In particular, the COS filing requirement states that the following information is required:[120]

a. Manager's Summary;

b. Summary and Cost Driver Tables;

c. Variance Analyses;

d. Employee Compensation Breakdown;

e. Shared Services/Corporate Cost Allocation;

f. Purchases of Non-Affiliated Services;

g. Depreciation/Amortization/Depletion;

h. Taxes/PILs;

i. Green Energy Plan OM&A Costs, if applicable; and

j. Conservation and Demand Management ("CDM") Costs, if applicable.

229. The utilities are instructed to include the following as part of the manager summary mentioned above:[121]

a. OM&A Test Year Levels;

b. Associated cost drivers and significant changes that have occurred relative to historical and Bridge years;

c. Overall trends in costs;

d. Inflation rates used for general OM&A and Wages/Benefits. The Board has determined that the GDP-IPI is the most relevant inflation rate for utilities with respect to IRM rate applications, and the applicant should consider this in adopting an inflation rate. If the applicant proposes to use an inflation rate other than the GDP-IPI rate determined by the Board, appropriate justification should be provided (such as studies and/or sources);

e. Staffing levels;

f. Drivers for changes in salaries and wages and related costs;

g. Business environment changes; and

h. Materiality thresholds that apply.

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[120] *Id.*, p. 27.

[121] *Id.*

230. Although the requirements mentioned above for both capex and opex might seem to suggest that the OEB conducts a detailed line-by-line examination of the capex/opex forecasts and provides a detailed funding prescription as a result, the OEB has in the past been more pragmatic. For example, in a recent rate case decision for Hydro One, the OEB stated that "[i]n some cases a detailed line by line examination has resulted in an equally detailed funding prescription from the Board. In other cases the Board has provided the applicant with an overall envelope of funding. In such cases the Board does not stipulate an approved amount of spending for any particular category of spending, but rather leaves to the applicant the freedom to apply that spending according to its own prioritization".[122]

231. The OEB also allows for limited number of deferral and variance accounts for flow through items that are outside of the control of the utilities (e.g., change in financial reporting standards). However, the OEB tries to limit the use of these deferral accounts believing that deferral accounts tend to provide disincentive for utilities to improve.

232. There are otherwise no true-ups to actual costs for distribution utilities.

7.4 COST OF CAPITAL

233. In Ontario, the cost of capital is divorced from the utility specific cost of service proceeding. The OEB uses a formula-based approach using Equity Risk Premium (ERP) to determine the fair rate of return on equity (ROE) for all of the regulated utilities. The ROE is set and subsequently adjusted annually, based on the long-term Canadian and A-rated Canadian utility bonds yields, in generic proceedings.[123] There is no utility-specific proceeding on the cost of capital.

7.5 ANALYTICAL TOOLS USED BY THE OEB

234. The OEB uses benchmarking to determine the productivity factor. The approach to benchmarking has been periodically revised and updated, and has included both an econometric model and unit cost analysis.

235. The OEB also requires utilities to do variance analyses comparing actuals to previously board-approved expense levels as part of their COS application. This variance

122 *Decision with Reasons*, EB-2009-0096, April 9, 2000, p. 12.

123 *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, Ontario Energy Board, EB-2009-0084, December 11, 2009, p. 5 & Appendix A.

analysis, along with other information filed as part of the cost of service application, informs the OEB on the appropriate levels of funding required by the utilities.

7.6 RULES FOR HOW THE OEB'S ANALYSIS IS TO BE CONDUCTED

236. The OEB closely scrutinizes the forecasts submitted by the utilities as part of the COS filings. Specifically, there is a through vetting of the capex/opex forecasts. However, the OEB is not bound by any prescription on how it should review and analyse the capex/opex forecasts. The OEB really has no constraints beyond the need to maintain efficiency of its processes.

7.7 COMMENTARY ON THE APPROACH

237. The OEB's approach to regulating electricity distribution utilities is in part driven by the fact that there are more than 80 individual distributors within its jurisdiction (few of which are investor owned).

238. The OEB's current approach is something of a hybrid: explicit cost forecasts are used to determine the revenue requirement for the first year of the new control period, but for the later years a "trend", based in part on productivity studies, is assumed. This approach does not cope well when significant changes in cost are expected, for example as a result of a step-change in capital investment. The OEB first developed an "incremental capital module", designed to allow rates to rise more quickly if there was a need for more rapid investment. The OEB is now considering a more explicit capex forecasting approach.

239. The OEB is currently coordinating a consultation process for developing a renewed framework for regulating electric distribution and transmission utilities. The intent of the new framework is "to support cost-effective modernization of the network while at the same time controlling rate and/or bill impacts on consumers".[124] Overall, the OEB hopes to improve certainty, coordination, and consistency with the new framework. On February 6, 2012, a straw man for the new framework was proposed which listed several differences between the current framework and the proposed framework. Some of the differences regarding treatment of capes/opex are:[125]

- Long-term regional planning and longer rate setting horizon utilized for optimal investments and cost savings.
- Pre-approval of multi-year capital plans with focus on reliability.
- "New performance expectations associated with investment planning and reliability. Potential for expedited review based on utility's effectiveness in prioritizing and pacing network investment with regard to bill increases to consumers. Financial consequences potentially tied to achievement of investment plan objectives."
- "Sever treatment of OM&A and capital to increase pursuit of operating efficiencies and recognize significant need for capital investment. Measures will be developed to ensure allocative efficiency."
- Period between COS reviews more flexible but "off-ramps" are more strict.

240. However, this is still a work-in-progress and the new regulations are expected to start taking effect in 2014/15.

[124] *Renewed Regulatory Framework for Electricity Frequently Asked Questions*, Ontario Energy Board, November 8, 2011, p. 1.

[125] Attachment A, *RRFE Strawman*, Ontario Energy Board, February 6, 2012.

8. RHODE ISLAND (RHODE ISLAND PUBLIC UTILITIES COMMISSION)

8.1 INTRODUCTION

241. The Rhode Island Public Utilities Commission (RIPUC) is comprised of two regulatory bodies: a three-member Commission, and the Division of Public Utilities and Carriers.

242. The RIPUC serves as a quasi-judicial tribunal with jurisdiction, powers and duties to implement and enforce standards of conduct. The commission holds investigational hearings involving the rates, tariffs, tolls and charges, and the sufficiency and reasonableness of facilities and accommodations of railroad, ferry boats, gas, electric distribution, water, telephone, telegraph and pipeline public utilities, the location of railroad depots and stations, and the control of grade crossings, the revocation, suspension or alteration of certificates issued, appeals, petitions and proceedings. Through participation in the Energy Facility Siting Board the commission's chair also exercises jurisdiction over the siting of major energy facilities. The electric distribution utilities under the RIPUC's jurisdiction include National, Grid, Pascoag Utility District and the Block Island Power Company. The RIPUC derives its authority for the review of utility conduct from Rhode Island GL§39-1-27.6, tariffs from GL§39-19-4, and appeals, petitions and proceedings from GL§39-1-30 to GL§39-1-32. Title 39 Public Utilities and Carriers[126] provides the complete set of laws unique to the regulation of utilities.

243. The Division of Public Utility and Carriers (RIDPU) is headed by an administrator who is not a commissioner, and exercises the functions not specifically assigned to the commission. The RIDPU certifies all public utilities; and has independent regulatory authority over the transactions between public utilities and affiliates, and all public utility equity and debt issuances.

244. For this study we reviewed the RIPUC's general ratemaking procedures for its electric distribution utilities and received assistance from RIPUC and RIDPU staff.

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[126] See http://www.rilin.state.ri.us/Statutes/TITLE39/INDEX.HTM

8.2 REGULATORY FRAMEWORK

245. The role of the RIPUC is to balance the interests of the ratepayer and the utility. Rates should be just and reasonable, i.e. adequate for the utility to be able to attract capital, and provide safe and reliable utility service, while expenditures should be prudent and only for items required in the provision of safe and reliable utility service. When a case is filed and docketed, interactions between the RIPUC and its staff must be "open" and include all parties to the docket. Informal interactions with the staff can occur only on undocketed matters.

8.3 ROLE OF CONSUMERS IN SETTING RATES

246. The regulation of utilities is performed by RIDPU which serves as the ratepayer advocate, i.e. the consumer representative. The RIDPU reviews the utility filing and makes recommendations to the RIPUC on a utility's request. Interveners can also participate in the hearings. As a result, settlements between the RIDPU, the utility, and other interveners are possible, but are subject to the review and approval of the RIPUC. There is also a Ratepayer Advisory Board which meets four times a year to review legislative proposals and comment on existing state laws relating to residential ratepayers.

8.4 THE PRICE DETERMINATION PROCESS

247. The RIPUC sets electric distribution company rates based on the 12 month period beginning at the end of the rate case suspension period (the rate year) and those rates are in place for three to five years. The RIPUC does not set transmission rates (these are set by the Federal Energy Regulatory Commission).

248. A full cost of service filing is performed in a rate case. Rates are determined based on forecasts. The accuracy of demand forecasts is less important following the introduction of a "decoupling" approach, under which the utility is "trued up" for changes in demand. If the utility is seeking a rate change, it must forecast its requirements. Adjustments may be made to the forecast if the regulator believes the adjustments are warranted by the evidence.

8.5 OPEX AND CAPEX

249. The RIPUC sets rates based on the 12 month period beginning at the end of the rate case suspension period (the rate year). If there is a rate year expense item that is projected to be at a significantly higher level than the subsequent year(s), the RIPUC may amortize the expense in the cost of service over a reasonable period. The RIPUC can be somewhat

flexible and creative within the "known and measurable" standard. For opex, a "known and measurable" standard is applied. Prior to another recent law dealing with capex, trending analysis was applied to capex in the rate setting process. Under current law, reviewing the need for the individual project is more relevant.

250. The new legislation was sought by National Grid as National Grid was seeking more current recovery on its capital investments, and was seeking the ability to get a rate change to pay for the growth in rate base in a manner less cumbersome, costly and time consuming than making a general filing for rate relief. In the DPU's opinion, evidence in recent rate cases indicated that National Grid's projection of the growth in capital spending was overstated. Due to the recent law, that issue is no longer debated in the rate cases, as the new mechanism tracks the actual spending and adjusts rates for the actual spending levels on an annual basis.

8.6 COST OF CAPITAL

251. The cost of capital is generally treated separately for the rate-setting process, but in a settlement about rates, "horse-trading" among issues may occur. The RIPUC has allowed "earnings sharing" as part of complex regulatory rate plans that included merger approvals, rate freezes and rate reductions in which the utility could exceed its authorized return through efficiency gains, and keep a portion of the revenue associated with the excess return. The balance of the excess return would be credited back to customers.

8.7 USE OF CONSULTANTS

252. The RIPUC has its own analysts and legal staff. The Commission can, and does, routinely issue its own data requests as part of a rate case discovery process. The RIDPU also issues data requests during its review, and may engage external technical consultants.

8.8 COMMENTARY ON THE APPROACH

253. Rhode Island is a fairly typical example of the North American approach to utility regulation, albeit that it utilises a "forward test year". Essentially, the approach is to forecast costs one year into the future with prices in the subsequent years (until the next reset) set on the basis of high-level assumptions about trends for both capex and opex.

254. The "known and measurable" standard implies that forecasts have to be closely based on historical costs. However, we note that recent pressures to increase investment in the networks have resulted in a change to the framework, such that the revenue requirement

associated with actual capex is automatically recovered in price adjustments within the control period.

9. GREAT BRITAIN (OFGEM)

9.1 LEGAL FRAMEWORK

255. Ofgem's principal objective is to protect the interests of existing and future consumers and is generally required to carry out its functions in the manner it considers best aimed at achieving this objective, wherever appropriate, by promoting effective competition. More specifically, in carrying out its duties Ofgem must have regard to the need to:

- secure that all reasonable demands for gas and electricity are met;
- ensure that licence holders are able to finance their activities; and
- contribute to the achievement of sustainable development.

256. In addition, Ofgem is also required to protect vulnerable customers and to carry out its functions in a manner in which, it considers, is best calculated to promote economic efficiency. Ofgem also has powers under the Competition Act to investigate suspected anti-competitive activity and is a designated National Competition Authority under the EC Modernisation Regulation. Ofgem also has concurrent powers with the UK Office of Fair Trading in respect of market investigation references to the Competition Commission.

257. Ofgem's powers and duties are largely provided for in statute (such as the Gas Act 1986, the Electricity Act 1989, the Utilities Act 2000, the Competition Act 1998, the Enterprise Act 2002 and the Energy Acts of 2004, 2008 and 2010) as well as arising from European Community legislation.

258. There is no provision for more detailed guidance to Ofgem on its assessment of cost forecasts as part of the price control process (although Ofgem is required to have regard to more detailed guidance in other areas, such as environmental matters).

9.2 OVERVIEW OF THE PRICE CONTROL PROCESS UNDER RIIO

259. After twenty years of implementing RPI-X regulation, Ofgem conducted a major review of its approach, subsequent to which it announced its intention to implement a new regulatory framework, known as the RIIO (Revenue=Incentives+Innovation+Outputs)

model.[127] As the acronym suggests, the main aim of RIIO is to link allowed revenues with the delivery of outputs and to take a more long-term perspective of network costs and service delivery. The first set of RIIO price controls are currently being implemented for electricity and gas transmission RIIO-T1, for the 2013-21 period. The review process for gas distribution and transmission started in summer 2010 electricity distribution has just been launched.[128]

260. According to Ofgem, the RIIO model has taken the elements of the old RPI-X framework that have worked well, and adapted other elements to secure a greater focus on: sustainability; long-term value for money; incentives for innovation; and greater engagement with customers. In practical terms the key changes between the previous regulatory regime and the RIIO framework are:

- Shifting from a 5 year to 8 year period of control.
- A greater emphasis on linking costs with outputs.
- Equal treatment of opex and capex incentives.
- Greater emphasis on long-term value for money rather than just efficient costs.
- The ability of third parties to refer settlements to the Competition Commission.
- The ability of companies to be “fast-tracked” through the review process.
- Enhanced customer engagement processes.

261. Within the RIIO framework, Ofgem has a building block approach to setting network price controls which starts with the regulatory asset value carried forward from the previous price control which is then adjusted in line with expected efficient expenditure and in the light of a company’s performance (rewards and penalties for delivery of outputs) and indexed to factors such as volume of connections and demand. Figure 12, below, from the RIIO handbook, describes the building blocks approach.

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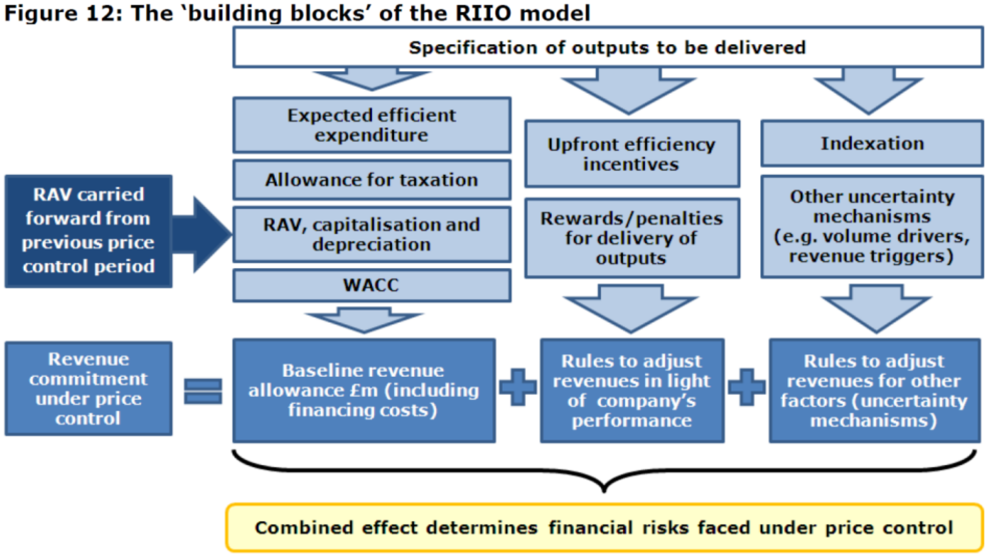
127 See *RIIO – A new way to regulate energy networks*, Ofgem October 2010 . Further details of RIIO can be found on the Ofgem RPI-X@20 website at http://www.ofgem.gov.uk/NETWORKS/RPIX20/Pages/PRIX20.aspx

128 For consultations and decisions concerning these price controls, please refer to the Ofgem website at: http://www.ofgem.gov.uk/Networks/PriceControls/Pages/PriceControls.aspx

Figure 12: The 'building blocks' of the RIIO model



262. The regulatory process starts with Ofgem developing a "strategy for the review" consultation document in Stage 1.[129] This sets the objectives for the review based on companies' past performance and sets out criteria for fast-tracking. Firms may be "fast-tracked" if they have provided a timely and "well justified" strategic business plan and other information which enables Ofgem to conduct a more rapid assessment.[130]

263. Ofgem expects network companies to present business plans centred round delivery of primary outputs. Companies are expected to set out the performance level they are proposing for primary outputs and, where the company is proposing a performance level different to Ofgem's baseline level, a clear justification of this variation is required.[131]

264. Ofgem then issues a request for information and data, including business plans. The companies are provided with a data template so that the data provided may be compared across entities, but the firms are not provided with a template for their business plans. This is a deliberate strategy by Ofgem as the aim is to obtain a narrative of the business plan told from the company's perspective.

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129 The approach to implementing the price control is set out in the *Handbook for implementing the RIIO model*, Ofgem, October 2010. The Ofgem Decision on Strategy for Consultation on the next transmission and distribution price control is published at the end of Stage 1. See:

http://www.ofgem.gov.uk/Networks/GasDistr/RIIO-GD1/ConRes/Documents1/GD1decisionbusplan.pdf

130 See Figure 18, p. 47 of the *RIIO Handbook* which describes what companies are required to include in their business plans.

131 See Ofgem *Business plan initial guidance* set out in an open letter to transmission companies in July 2010.

265. In Stage 2, companies submit business plans in line with the high-level approach set out by Ofgem in its strategy. At this stage Ofgem identifies the companies on which a decision may be fast-tracked and then commences more intense scrutiny of the other companies. In Stage 3, the companies revise their business plans, as may be required, and Ofgem undertakes a detailed assessment. In the current transmission review being conducted by Ofgem, two companies have been fast-tracked. The price control is set in Stage 4, with the development of initial and final proposals (for companies that have not been fast-tracked).

Focus on Long-Term Value for Money

266. A key pillar of the RIIO approach is for companies to demonstrate value for money over the longer-term. A well-justified plan will be one that provides information on the longer-term strategy for network development and delivery of long-term value for money. Ofgem expects companies to link this to their strategy for contributing to meeting the government's carbon and renewable targets. In particular companies need to take into account the national need for new electricity networks, as set out in the energy National Policy Statements (NPSs) designated from time to time under the Planning Act 2008, and the National Development Priorities, as set out in the second National Planning Framework for Scotland.

267. Companies are also required to show that they have not only considered the expenditure they need for the duration of the price control but also the implications this expenditure will imply for required investment and associated efficiency beyond the price control period. They will need to justify proposed expenditure for the eight-year period in the context of the longer-term 10-15 year strategy. Ofgem therefore expects the companies' business plans to comprise an asset management strategy consistent with asset life cycles and include evidence that network companies have considered alternative options for delivering outputs at long-term value for money.

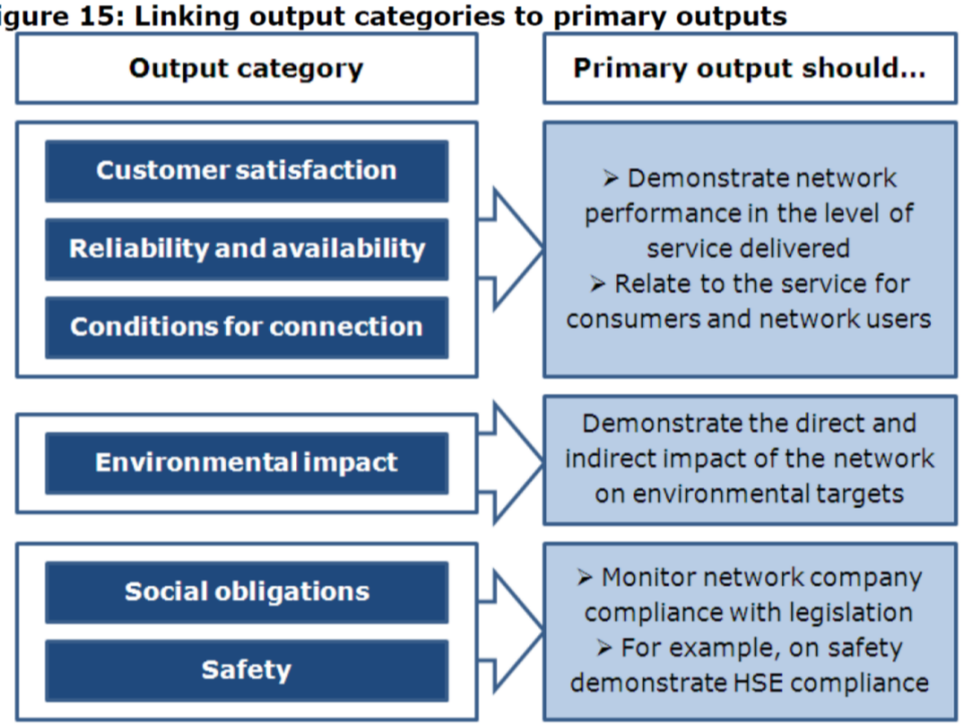
268. Whilst a longer period of control may provide greater incentives for efficient investment, the longer control period also creates greater uncertainty in forecasting key parameters of the price control. The key, according to Ofgem, is to establish a baseline of *ex ante* funding and to manage future uncertainty in a symmetrical way so that risks are balanced evenly between consumers and enterprises. An important part of the work is to establish where the load and non-load related costs are likely to be over the duration of the

control, accepting that demand related expenditure is much less certain and more difficult to forecast than the non-demand expenditure.

Output Driven

269. A key RIIO theme is a greater focus on delivery of outputs and linking costs to outputs such as asset performance. The RIIO process identified six key output categories, or key areas of delivery, for network companies. The output categories are: safety; environmental impact; customer satisfaction; reliability; conditions for connection; and social obligations. Figure 15 from the RIIO handbook demonstrates the linkage between output categories and primary outputs.

Figure 15: Linking output categories to primary outputs



270. In an open letter to transmission companies involved in the first price control under RIIO,[132] Ofgem stated that companies would need to demonstrate a clear link between expected efficient expenditure and primary outputs including:

- the total cost of the particular output on a standalone basis or total costs related to a business strategy (e.g., asset maintenance strategy);

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[132] http://www.ofgem.gov.uk/Networks/Trans/PriceControls/TPCR5/ConRes/Documents1/Open%20letter%20TPCR5%20way%20forward.pdf

- cost interactions from delivery of outputs together;
- costs related to innovation projects that are related to delivery of long-term value for money; and
- the cost impact for each primary output of a small change to the level of that output.

271. For high value projects, or projects where there is uncertainty about what is needed, Ofgem said that the company should set out details of how costs might vary under different scenarios and indicate the "base" assumption underpinning their expenditure forecast and how they propose to manage the uncertainty around that base forecast.

272. In the first electricity transmission consultation under RIIO, Ofgem set outputs in each of the six areas apart from social obligations.[133] For example, for customer satisfaction outputs, Ofgem decided to put in place a primary output that related to customer/stakeholder views of each TO's performance. and that the primary output would be supported by two separate financial incentives. The first, worth up to +/- 1% of allowed base revenue, would be based on results from a customer/stakeholder satisfaction survey. The second would be a discretionary reward available where TOs were able to demonstrate that their effective stakeholder engagement led to exceptionally positive outcomes for customers. This was potentially worth up to 0.5% of allowed base revenue. Ofgem has also committed itself to working with companies in developing customer satisfaction surveys.

273. On reliability outputs, there will be a financial incentive driven by performance, in addition to a compulsory minimum standard of performance and secondary deliverables in four areas: asset health, criticality and replacement priorities (risk), system unavailability and average circuit unreliability (ACU), faults, and failures.

274. One of the effects of a greater focus on achieving specific output targets has been to change the type of data that Ofgem collects. Under previous reviews Ofgem focussed primarily on collecting regulatory accounting data which proved not always to be well targeted for the purposes of the analysis that Ofgem ultimately wished to carry out, and there was insufficient information for assessing outputs. The current approach is to focus more on information about the condition of assets as well as more targeted information on why expenditure may or may not be required in specific areas.

[133] See *Strategy for the next transmission price control - RIIO-T1 Outputs and incentives*, Ofgem, (March 2011).

275. Ofgem has developed cost reporting rules to ensure that costs are reported on a consistent basis across activities and companies over time. This helps to reduce distortions in how costs are reported where there are potential trade-offs between activities (for example, integrity capex versus maintenance and faults opex). Ofgem said it looks for companies to report in their business plans how they are optimising asset expenditure. In this respect Ofgem is looking for "whole asset life cost" solutions, with the onus on companies to explain why they are taking a particular approach.

9.3 PROCESS ISSUES

276. The price control process is initiated and driven by Ofgem. For example, the current transmission price review process was initiated with an Ofgem "strategy" document which, for example, set out a proposed range for some of the financial inputs to the price control.[134] All stakeholders have the opportunity to submit their views and influence Ofgem's thinking, both on Ofgem's proposed strategy as well as proposed decisions on price controls. One of the new regulatory features under RIIO is the ability of consumers and other third parties to challenge price control decisions, including a new right of referral to the Competition Commission.

277. As discussed below, during the price control process, Ofgem provides guidance on how companies should provide business plans but is not overly prescriptive. It is, however, more prescriptive about the format and content of the actual and forecast data that companies are required provide.

278. During the review process Ofgem reviews data and business plans submitted by companies; holds detailed discussions; and also typically engages engineering consultants to review the condition of assets as well as proposed investment plans. If such reviews suggest that companies' forecasts do not match their business plans, or that there are doubts about the way in which companies have estimated their costs, Ofgem may ask companies to submit revised forecasts or, alternatively, may itself adjust the companies' forecasts. Ofgem has a great deal of discretion in the price control process but must always provide well-justified reasons for its decisions.

[134] For example, *Decision on strategy for the next transmission price control - RIIO*-T1, Ofgem (March 2011), set a range for the cost of equity (6.0% to 7.2%), but did not specify anything about notional gearing because the level of gearing would depend on the risk in the cash flows implied by the business plans (paragraphs 8.16 and 8.22).

279. We discuss below various issues that may arise in the price control process.

Data Requirements and Cost Assessment

280. Ofgem worked closely with the companies in developing reporting tables to help ensure consistency in the submission of data and facilitate the process of cost assessment. The data template requires network companies to provide 15 years of forecast data covering the remainder of the current price control, the period of the coming price control and five years of future data. The process allows companies to update the longer-term data as more information becomes available during the price control period. The forecast data collected as part of the price control process is in addition to the incurred cost data that Ofgem collects on an annual basis.

281. Ofgem has stipulated that the cost data submitted should be consistent with the information submitted by parties in their business plans. To this end, the cost data are required to provide evidence that companies need to do the work they are proposing, that they have considered alternative options and that the costs of delivery are appropriate. This will include taking into account the longer-term development of their networks.

282. For major projects, companies will need to demonstrate that they have considered and consulted on all reasonable alternative options (e.g., different routes, undergrounding, subsea cables) and taken appropriate account of uncertainty.

283. Ofgem expects companies to use a range of tools in demonstrating the efficiency of their forecast costs, including internal and external benchmarking evidence and market testing. This might entail providing comparative costing of high volume / low cost work and itemizing unit costs of specific items of expenditure. Total costs are also provided to enable comparisons to be made at an aggregate as well as itemized level, where appropriate.

284. Ofgem considers efficiency through its "toolkit" approach to cost assessment, described below.

285. In assessing costs Ofgem typically develops a number of drivers and identifies its preferred drivers for each activity. Ofgem then discusses these views with the companies in setting appropriate allowances. Ofgem is not obliged to accept companies' forecasts and may ask companies to submit adjusted or revised forecasts if the data and information submitted is not consistent with the business plan or does not conform to Ofgem requirements.

Forecasting and Managing Uncertainty

286. As part of the information request companies are asked to forecast their expenditure under various scenarios of generation, connection and demand over a 10-15 year period. Ofgem recognizes that forecasts that extend over a timeframe beyond the upcoming price control period are likely to be subject to greater levels of uncertainty.

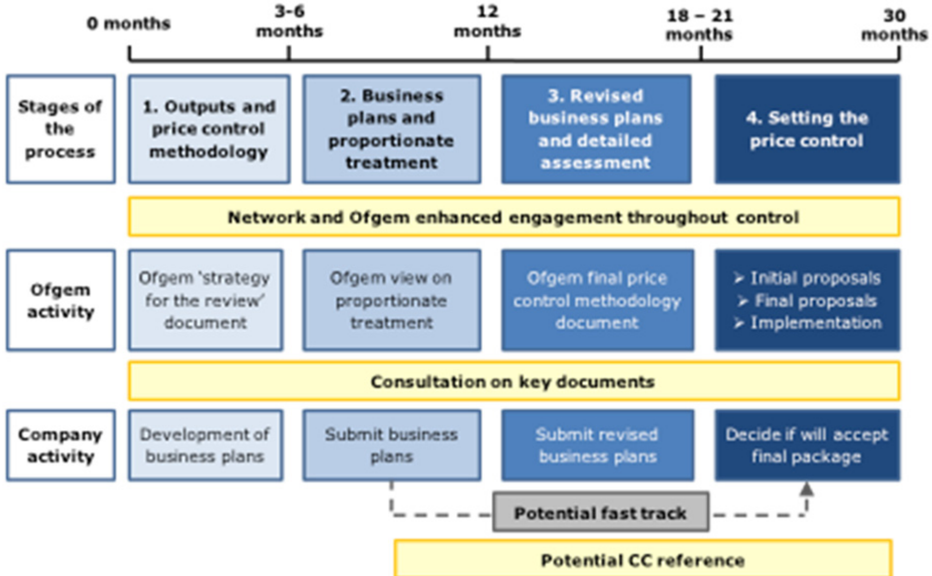
287. Ofgem also asks for load and non-load related expenditure forecasts matched to those scenarios.

Timing of the Price Control

288. Figure 2 below, from the RIIO Handbook, describes the time-line for the price control. The whole process takes up to two and a half years. In the first stage, which takes 3-6 months, Ofgem develops the strategy for the review and during this time the companies develop their business plans. In the second stage, during months 6-12, companies submit business plans. Network companies that are not "fast-tracked" (discussed below) are then ask to submit revised business plans at stage 3. At stage 3, which occurs during months 18-21, Ofgem scrutinizes the revised business plans, focusing on areas of particular concern, with the aim of finalising the methodology to be used in the price control and assessing an appropriate level of cost and revenue for the companies. During stage 4, months 21-30, Ofgem develops initial and final proposals for the network companies and associated licence drafting. During this stage Ofgem does not request or receive any new data from network companies, save for identified errors,[135] and would not expect to change its methodology.

[135] *RIIO Handbook*, paragraph 2.9.

Figure 2: Overview of the process and indicative timings of a price review



Fast Tracking

289. On receipt of the business plans during stage 2 of the price control, Ofgem decides which companies will face more or less intensive scrutiny. Less intensive scrutiny may include fast tracking a company (i.e. reaching an early decision on the price control). If Ofgem decides to fast track a company it will consult on its approach before reaching a decision. If the decision to fast-track is taken, Ofgem then finalizes all elements of a company's price control settlement at stage 2, including drafting licence changes. Fast tracked companies therefore move straight to the end of stage 4. Whereas non fast-tracked companies move into stage 3.

290. In the first implementation of the RIIO price controls, two companies, Scottish Hydro Transmission (SHETL) and Scottish Power Transmission (SPTL), have been fast-tracked.[136] In an open letter to market participants, Ofgem explained that it used five broad criteria to assess the suitability of business plans for fast-tracking:[137]

- Process: has the company followed a robust process?
- Outputs: does the plan deliver the required outputs?
- Resources (efficient expenditure): are the costs of delivering the outputs efficient?

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136 See Ofgem's *Final Proposals* for SHETL and SPTL.

137 http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/Further%20assessment%20of%20RIIO-T1%20business%20plans.pdf

- Financial costs: are the proposed financing arrangements efficient?
- Uncertainty/risk: how well does the plan deal with uncertainty and risk?

291. According to Ofgem, fast-tracking means "…finalising the price controls of a company at an early stage in the process on the basis that we consider its proposals are well- justified and in the interests of consumers".[138]

292. Fast-tracking is part of the "proportionate treatment" approach under RIIO. Although RIIO is still in its infancy, Ofgem believes that fast-tracking has thus far proved very successful in encouraging companies to provide more information up-front, to plan on a more long-term basis; and to consider how to better manage uncertainty.

Engagement with Companies

293. Ofgem engages both with companies both formally and informally throughout the review process. At the beginning of the process there are numerous bilateral and other meetings in which Ofgem explains their approach and strategy for the review. There are then meetings throughout the process which may be part of the formal process but which may also be called at the behest of the company or Ofgem. Ofgem has an "open door" policy but also tries to have a proportionate approach to identify the big issues and concentrate intensive discussions on those.

Engagement with Customers

294. The Consumer Challenge Group was set up in July 2008 to assist Ofgem in ensuring that the consumer view was fully considered during its Electricity Distribution Price Control Review during 2008-09. According to Ofgem, the Consumer Challenge Group has been very useful in presenting an alternative view to the regulated companies and has helped balance perspectives during discussions with the Ofgem Board.

295. One of the aims of RIIO is to enhance the involvement of customers. This is in part achieved through encouraging companies to take a more active role in engaging customers through being more open and transparent and keeping customers informed of business plans. Ofgem has seen a significant improvement in and the companies engaging more actively with customers, perhaps in part because of tighter planning regulations which make it difficult for companies to obtain approval for large investment projects without engaging

[138] See page 3 of *RIIO-T1: Final Proposals for SP Transmission Ltd and Scottish Hydro Electric Transmission Ltd*, Ofgem (April 2012).

customers more directly, and as companies have recognised the benefits of gathering appropriate information and views from a wider range of stakeholders in developing their forecasts.

296. Ofgem has invested time in educating consumers though meetings and presentations which has led to customers being more actively involved in the regulatory process. For example, the "Price Control Review Forum" was a series of Ofgem-led meetings open to a cross-section of industry stakeholders and network companies to allow views to be shared and issuers debated.

Engagement with Investors

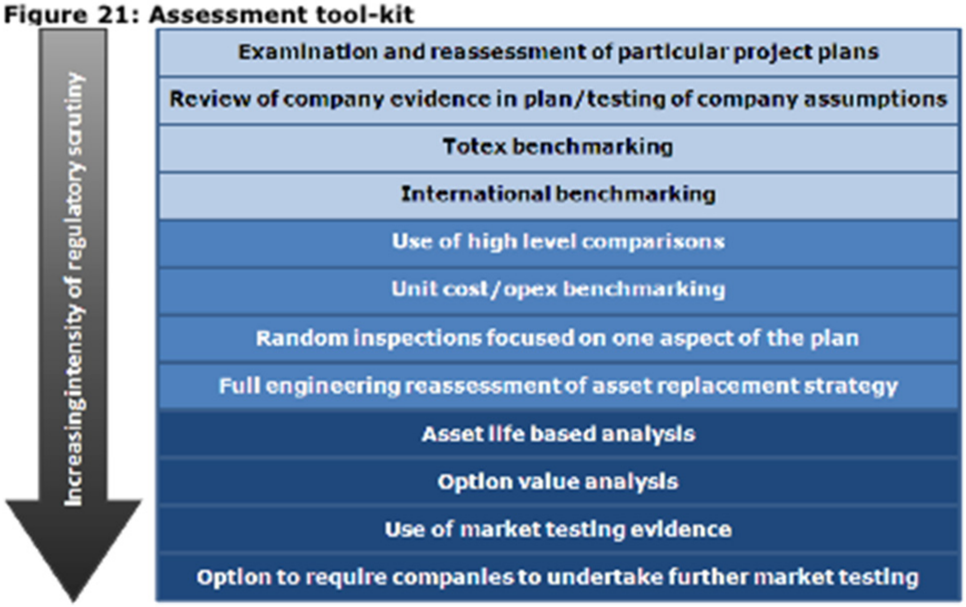
297. Ofgem and the companies hold discussions with investors throughout the price control process to discuss main issues pertaining to companies' ability to raise finance and surrounding the riskiness of businesses. Ofgem needs the revenue package to be financeable for an efficient company and therefore wants to ensure that investors and credit rating agencies believe that the revenue control is sound and enables companies to raise finance.

9.4 TOOLS USED BY THE REGULATOR

298. A principal aim of Ofgem in assessing business plans is to be proportionate and focus on areas where scrutiny can add the greatest value. Ofgem does not focus excessively on each project or individual programme of activities, but will apply more detailed scrutiny to areas of the plans that are of greater value or importance, and will review a sample of projects where it is inappropriate or disproportionate to review all expenditure in detail.

299. Ofgem uses a range of tools to assess the base revenue requirement which may range from a detailed bottom up assessment of a large investment project to using benchmarking for specific items of expenditure. Figure 21 below, reprinted from the RIIO Handbook, provides the elements of the assessment tool-kit.

Figure 21: Assessment tool-kit



300. Ofgem will not typically use all of the tools during any price control but, rather, select tools that it deems most appropriate for assessing the particular area of costs of investment activities.[139] This might include both higher level and more disaggregated analysis. It also includes comparisons of both forecasts and historical data across companies. If the costs a company identifies are high relative to other companies and past performance, then it will be for the company to demonstrate long-term efficiency. In assessing costs, therefore Ofgem examines:

- Justification for expenditure and evidence on efficiency;
- Total expenditure benchmarking and disaggregated benchmarking;
- Historical trend analysis and review of asset volumes;
- Unit cost analysis;
- Expert review; and
- Real price effects and on-going efficiency.

301. When Ofgem assesses companies' forecasts it considers whether the forecasts incorporate a reasonable level of productivity improvement, which Ofgem would expect an efficient company to make (on-going efficiency improvements). Ofgem also assesses whether the companies have robust justification for the level of changes in input prices

[139] http://www.ofgem.gov.uk/Networks/GasDistr/RIIOGD1/ConRes/Documents1/GD1decisioncosts.pdf

(e.g., wages) relative to the retail price index (RPI), which Ofgem refers to as real price effects (RPEs).

302. Ofgem uses a range of benchmarking options to undertake a high level assessment of historic cost efficiency during the most recent price control period. Benchmarking options include, but are not necessarily limited to:

- Benchmarking of total costs;
- Benchmarking of specific categories of costs (e.g., IT costs, network operating costs);
- Assessment of trends in productivity improvements over time; and
- International benchmarking.

303. As part of the assessment of the quality of a company's business plan Ofgem benchmarks the forecast costs to others in the sector, where feasible. Ofgem also compares the costs in the plan to historic cost performance.

304. Benchmarking is used by Ofgem for assessing both transmission and distribution businesses, but in different ways. In transmission Ofgem carries out total expenditure analysis, based on historical international data, to get an indication of how UK companies compare internationally. But this is difficult to do in practice due to accounting differences and other problems in comparing costs between countries. Whereas for distribution Ofgem uses regression and statistical analysis to compare efficiency, mainly using corrected ordinary least squares panel analysis. Ofgem has so far not used stochastic frontier analysis given the limited number of comparators. Ofgem places greater weight on forecasts if data are reliable, but will give more emphasis to benchmarking historical data if forecasts appear unreliable or subject to a high level of uncertainty.

9.5 COMMENTARY ON THE APPROACH

305. We note that Ofgem's governing legislation provides no detailed guidance as to the assessment of cost forecasts (for example, neither the use of RPI-X nor a building-blocks approach is mandated). The legislation requires Ofgem to ensure that the regulated service providers can finance their functions, and Ofgem is required to promote efficiency. Otherwise, Ofgem has broad discretion.

306. Ofgem's RIIO approach is the result of an extensive (two year) review of its experience with RPI-X type price controls. The new features of RIIO which are associated with assessing capex/opex forecasts are a greater reliance on "business plans" and outputs,

the possibility of fast-tracking, and a greater emphasis on engagement with customers. There is necessarily limited evidence on what this will mean in practice, since the first RIIO review process is not complete for the two transmission service providers that have not been fast-tracked, and Ofgem is only just starting the review process for the electricity distribution companies. However, Ofgem's view is that the "fast-tracking" option has encouraged the companies to work more constructively during the review process.

307. Over time, the scope of Ofgem's data collection has evolved, and it now collects extensive data on asset condition and performance (in addition to cost data). Ofgem collects direct information on asset condition because of the lag between condition and performance measures (reliability). Information on asset condition and criticality also provides greater clarity on why companies are forecasting costs in a particular area.

308. Ofgem has also done a lot of work with the companies to encourage them to provide information in a useful format, but this is an on-going process with some companies apparently still not providing data in a format that is consistent. The biggest challenge has been to get consistent data over time. Ofgem has challenged views from the companies that they have a large range of special factors that potentially make comparisons difficult.

309. Ofgem has also changed its information gathering to put more emphasis on the link between forecast costs and planned outputs—for example, by collecting information on the condition and performance of assets.

310. The longer review period under RIIO means that companies have to think harder about uncertainty, and the drivers of cost around a baseline scenario.

311. We note that within Ofgem's overall timetable for the review process there is a period of nine months at the end (for companies that have not been fast tracked) where Ofgem has said that it will not accept new information from the companies (apart from correcting errors).