INCENTIVES FACED BY NETWORK SERVICE PROVIDERS
AUSTRALIAN ENERGY MARKET COMMISSION

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DRAFT REPORT

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CONTENTS

EXECUTIVE SUMMARY

The Australian Energy Market Commission (AEMC) has commissioned Cambridge Economic Policy Associates (CEPA) to assess the regulatory financial incentives, and other non-regulatory incentives, that electricity network service providers (NSPs) in the National Electricity Market (NEM) face under the current regulatory framework.

In particular, the AEMC are interested in whether there is evidence to support persistent stakeholder concerns that the current incentive arrangements create (or fail to correct for) a capital expenditure (capex) bias. That is, where NSPs may be biased towards inappropriately choosing capex solutions over operating expenditure (opex) solutions. Such a bias may include preferring network rather than non-network solutions and in-house (including the use of ring-fenced affiliates) rather than outsourced solutions. If a bias does exist, it is of particular concern given the increasing availability of alternatives to 'traditional' (NSP-initiated, capex-based) approaches to delivering regulated network services, provided by the NSP or third parties.

In this report we seek to:

- Establish whether the current regulatory framework in the NEM creates a financial incentive for NSPs to prefer capex to opex (or vice-versa).
- Identify any other qualitative reasons that might create an incentive to favour a particular approach or alternatives.

Regulatory incentive mechanisms

A key design aspect of the NEM regulatory framework, and recent rule changes, is to incentivise genuine outperformance and innovation in order to mimic the operation of a competitive market. At the time of the framework's development, the efficient, safe and reliable conveyance of electricity primarily required capital investment in long-lived assets (wires, poles, etc.), and the design of the framework reflected this.

The framework is continually evolving with new rule changes. A suite of incentive mechanisms is now in place to meet the requirements set out in the various rule changes. However, using a suite of mechanisms that have been developed at different times over the last 10 to 15 years in response to rule changes, can result in unintended incentives on NSPs, or the NSPs misinterpreting and responding to the incentives incorrectly.

The regulatory incentives include incentives that may influence how NSPs prepare their regulatory proposals (pre-allowance determination incentives) and incentives that may influence their decision-making process once the determination is complete (post-allowance determination incentives). While we describe these incentives separately, NSPs would consider any post-allowance incentives when developing their regulatory proposals.

The two key pre-allowance determination incentives are:

- The AER's approach to assessing expenditure proposals. There is a general financial incentive on NSPs to gain high allowances in order to increase their scope for outperformance and cover the risk of outturn costs being higher than expected. The AER typically relies on benchmarking to assess opex to check/ determine a base-year allowance to roll-forward. As this needs to be reviewed at each price control, this is a repeat game. Capex requires an assessment of a greater range of 'bespoke' projects. As these are one-off assessments, the process is 'done-and-dusted' in a single price control review.
- The cost of capital allowance (the weighted average cost of capital (WACC)). The AER provides detailed guidelines on how it will determine the allowed WACC. The NSPs therefore have reasonable visibility of what the allowed WACC will be and therefore their scope for out/underperformance. This may influence decisions on what capex projects to include in the regulatory proposal. While the WACC is adjusted for the systematic risk faced by the Benchmark Efficient Entity (BEE), the business specific risks of a company are still an important consideration for investors, and debt providers. Therefore, these stakeholders may be concerned if companies' management start adopting alternative solutions that may have greater uncertainty around them, even if the overall expected cost is lower.

There are three explicit financial incentive mechanisms that are intended to influence the NSPs during the price control:

- The Efficiency Benefit Sharing Scheme (EBSS). This was designed to equalise the NSPs' incentives throughout the price control to achieve opex efficiencies. The EBSS was introduced for use in determinations from 2008.
- The Capital Efficiency Sharing Scheme (CESS). This was designed to equalise the NSPs' incentives throughout the price control to achieve capex efficiencies. It was also intended to help balance the incentives between capex and opex. The CESS was introduced for use in determinations from 2013.
- The Demand Management Incentive Scheme (DMIS). This is designed to encourage NSPs to appropriately consider demand side management solutions as an alternative to capex. The DMIS was introduced for use in determinations from April 2018 (including use in existing determinations).

Observing a capex bias

In practice, observing a capex bias is difficult, as there is a myriad of factors that influence NSPs' decisions, both when (1) they develop their regulatory proposals and (2) respond to their allowances and operating conditions. The latter includes: changes in capitalisation policies, demand being higher or lower than forecast, and changing incentive mechanisms. In addition, there is a lack of a counterfactual (i.e., a bias-free scenario) to compare with. This limits the usefulness of analysing historical data.

While the usefulness of any comparisons is somewhat limited, we have used available data to assess the NSPs performance during their most recently completed regulatory determination period. This covers a period where the EBSS was in place, but not the CESS or DMIS.

For DNSPs, we found that the DNSPs generally outperformed (spent less than) their capex allowances (only three underperformed), but only four outperformed their opex allowances. However, because forecast demand did not eventuate, augmentation capex was not required and therefore the capex outperformance is likely to be higher than under a counterfactual where demand did eventuate as forecast. All the transmission NSPs (TNSPs) outperformed both opex and capex, however their capex outperformance was significantly higher.

The capex outperformance could indicate a greater level of asymmetric information, between the NSPs and the AER, compared to opex. Alternatively, the outperformance (or lack thereof) against opex could indicate a lower financial incentive compared to capex. However, given the lack of a counterfactual and our inability to disentangle the different factors influencing the NSPs' spending, we cannot conclude either way whether there is a capex bias or not.

Modelling the financial incentives

As the findings from the available data are limited, we modelled the financial incentives under the regulatory framework. Our model uses the underlying assumptions and mechanisms from the AER's post-tax revenue model, roll forward, EBSS and CESS models.

We have considered the financial modelling on the basis of two broad alternative assumptions:

- The NSP faces a choice between two equally efficient opex or capex solutions that deliver the same outcomes. In this case, we assume the NSP is responding to a change in output requirements and can implement an opex or capex solution. This solution has a finite duration. At the end of the solution's useful life, the opex allowance is assumed to be adjusted back to the original opex allowance based on original level of outputs.
- The AER's approach, where the EBSS and CESS are used to provide time-independent incentives on opex and capex. If opex efficiencies (or inefficiencies) occur in perpetuity and the WACC is 6% then the incentive strength on opex and capex will be equal. We note that if the opex efficiencies (or inefficiencies) do not occur in perpetuity, the EBSS will reverse any original reward/penalty such that the NSPs should only gain/bear the time value of money (i.e., the WACC in the original saving/overspend).

To model these assumptions, we compare present value (PV) equivalent opex or capex 'solutions'. The solutions are assumed to last for the same time period and deliver the same

levels of reliability and safety. That is, the opex solution is in place for the length of the alternative capex solution's useful asset life. However, under the second broad assumption, we assume that opex continues after the end of the solution life and the EBSS applies at this point.

We assess the financial incentive strength by dividing the net present value (NPV) outcome for a capex 'solution' by the NPV outcome for the PV equivalent opex 'solution' (the 'NPV ratio'). An NPV ratio of 0.5 means that the NSP's financial benefit from underspending on opex will be twice as great as that of a capex solution, while a 2.0 ratio means that a capex solution delivers twice as great as that of an opex solution. This means that a reduction in opex rather than capex will increase investors' overall returns.

The findings from this exercise are:

- Under the first broad assumption, our modelling indicates that there is a positive financial incentive for NSPs to prefer capex to opex, assuming that such a trade-off is possible. This incentive diminishes as the assumed life of the asset - and therefore the duration of the opex solution - increases. However, the incentive remains positive for the more common network asset lives of 40 to 50 years.
- Under the second alternative assumption, our modelling indicates that that achieving capex efficiencies may provide a slightly higher financial return than achieving opex efficiencies (i.e., an incentive to prefer opex rather than capex). This is driven by the different tax outcomes.
- The DMIS increases the incentive to undertake opex, but only for certain projects.

Key findings

We have analysed the explicit financial incentives built into the regulatory framework and the other factors that may influence NSP behaviour (such as risk aversion and reputational incentives). Our analysis indicates that:

- **The financial incentives for NSPs vary depending on individual circumstances, but they are not equal between opex and capex.** If we assume that an NSP is considering whether to undertake equally efficient opex or capex solutions, that deliver the same outcomes, our modelling indicates that the NSP will have a financial incentive to prefer capex over opex. In contrast, if we assume the EBSS and CESS equalise the incentive strength over time to encourage efficiencies, then there is a slight financial incentive for the NSPs to prefer to achieve capex efficiencies over opex efficiencies.
- **There is no simple fix to the EBSS and CESS to equalise the incentives on opex and capex.** The basis of the CESS *ex ante* sharing factor depends on an assumed in perpetuity opex saving and a fixed discount rate of 6%. Neither of these assumptions are likely to hold in practice. *Prima facie* the most straight forward approach for

aligning the incentives would be to set an *ex ante* sharing factor for opex. However, in line with our modelling on the 'choice' between an opex or capex solution, this approach does not address the financial incentive if the actual cost of capital is different from the allowed cost of capital as, for example, a capex solution will be preferred if the actual cost of capital is lower.[1]

- **The DMIS provides an incentive, for specific projects, to favour opex demand management over capex.** The DMIS can, depending on the specific requirements of the project, more than fully offset the financial bias in the underlying framework of the EBSS and CESS.
- **The AER assess capex differently from opex.** The AER typically uses top-down opex benchmarking and trends forward a base level of opex, while capex requires a more bespoke assessment as projects can vary over time. Therefore, NSPs may seek to avoid opex solutions in order to avoid appearing inefficient on the opex benchmarking. This creates both a financial incentive, as opex is potentially more likely to be reduced than capex, and a reputational incentive.
- **The combined effects of the incentive mechanisms are complex.** We have found it difficult to model the interaction between all of the financial incentives. Therefore, we predominately focused on the CESS and EBSS. Each NSP has to assess the incentives and determine how they will respond. Greater complexity increases the likelihood that NSPs will respond in unintended ways.
- **Network capex is likely (at least compared to more innovative opex solutions) to provide more stable cash flows to the NSPs.** Aside from the DMIS, there is no explicit working capital allowance (margin on opex) for changes in the operational leverage of individual NSPs and any associated changes in their risk profile from adopting opex solutions with greater levels of uncertainty around future costs. Therefore, risk averse investors/ management may seek to avoid opex projects with greater uncertainty around future costs and outputs.
- **Anecdotal evidence (including company submissions, financial analyst reports, and credit rating agency reports) indicates that investors are interested in stable long-term cash flows.** Therefore, any shift away from maintaining or growing the RAB will reduce the magnitude of future profits, and therefore future dividend growth. This is regardless of the theory that they should be indifferent to a opex or capex solution if the allowed cost of capital is set equal to their actual cost of capital, and that the size of equity and debt will reduce alongside the RAB.

[1] Ofgem's and Ofwat's solution to this issue was to simplify the incentive mechanism by treating opex and capex together and capitalising a proportion of the total. This approach does lead to changes in other part of the regulatory framework (such as the treatment of depreciation and the need for financeability assessments).

More generally we note that the current regulatory framework was developed with a RAB based approach at its heart. This incentivised capex, as no return (e.g., a margin) was provided on opex to cover working capital. The provisions of the current regulatory framework have in turn attracted a certain type of investor. This may create a self-reinforcing capex bias.

Overall, the analysis we have undertaken highlights the complexity of the interaction between the incentive mechanisms and how the perception of the incentives can change depending on the assumptions made. Under one set of assumptions – when assuming the NSP is comparing equally efficient opex or capex solutions – there is a financial incentive to prefer capex over opex. In contrast, if we assume that the NSP is assessing the incentives from making efficiency savings (or inefficient overspends) there is a slightly higher financial incentive to achieve capex savings compared to opex savings. Non-regulatory incentives indicate a capex bias. While we are unable to prove the presence of a systematic capex bias, we are similarly unable to conclude that the incentives provided by the current regulatory framework are balanced across capex and opex.

1. INTRODUCTION

The AEMC is concerned that if a capital expenditure (capex) bias exists, NSPs may inappropriately choose 'traditional' capex approaches over more efficient alternative approaches that instead utilise operating expenditure (opex). As it is expected that the availability of alternative solutions will increase in the future, particularly for distributed energy resources, the materiality of an existing capex bias will increase.

A capex bias could result from a number of different factors, including: financial incentives embedded within the framework; information asymmetries, and how the AER approaches the assessment of opex and capex; and NSPs' corporate culture that may favour particular approaches.

In this report we seek to:

- Establish whether the current regulatory framework in the NEM creates a financial incentive for NSPs to prefer capex to opex (or vice-versa).
- Identify any other qualitative reasons that might create an incentive to favour a particular approach or alternatives.

The Australian Energy Market Commission (AEMC) has commissioned Cambridge Economic Policy Associates (CEPA) to provide modelling and analysis on the regulatory financial incentives - and other non-regulatory incentives - that electricity network service providers (NSPs) in the National Electricity Market (NEM) face under the current National Electricity Rules (NER). The incentive-based regulatory framework building-block approach is set out in Chapters 6 and 6A of the NER.

In particular, the AEMC are interested in whether there is evidence to support persistent stakeholder concerns that the current incentive arrangements create (or fail to correct for) a capital expenditure (capex) bias. That is, where NSPs may be biased towards inappropriately choosing capex solutions over operating expenditure (opex) solutions. Such a bias may include preferring network rather than non-network solutions and in-house (including the use of ring-fenced affiliates) rather than outsourced solutions.

If a bias does exist, it is of particular concern given the increasing availability of alternatives to 'traditional' (NSP-initiated, capex-based) approaches to delivering regulated network services, provided in-house by the NSP or out-sourced from third parties.

1.1. Overview of the current regulatory framework

The building blocks regulatory framework prescribed by the NER was developed to address the natural monopoly characteristics of energy networks. At the time of the framework's development, the efficient, safe and reliable conveyance of electricity primarily required capital investment in long-lived assets (wires, poles, etc.). Customers would benefit from these investments over the life of the assets, which creates a mismatch between when the costs are incurred and when the benefits accrue. As such, the regulatory framework was primarily focused on how to address this mismatch with regard to capex.

At the time, opex was primarily seen as costs that had to be incurred in order to enable the operation of the network. With the emergence of distributed energy resources (DER), improved real-time information and new innovations, it is expected that there will be increasingly effective alternatives to traditional capex approaches. Subject to the AER's ring-fencing guidelines,[2] to the extent that NSPs use DER to deliver their services,[3] they would be expected to contract with third-parties or ring-fenced affiliates to do so. As such, it is expected that the provision of NSP services would increasingly involve opex, rather than capex.

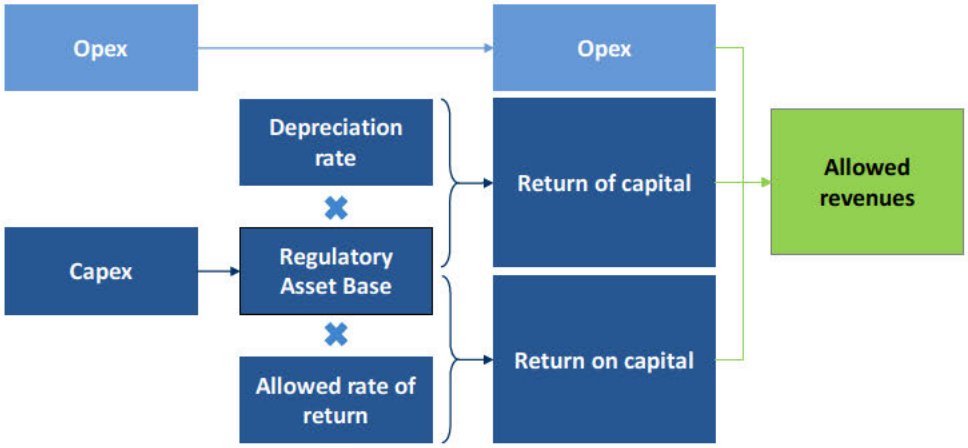
In order to support the achievement of the National Electricity Objective (NEO), the regulatory framework needs to incentivise NSPs to make efficient investment decisions, regardless of whether they use opex or capex.

The rest of this section describes how the regulatory framework treats opex and capex, and identifies the reasons a bias in favour of capex might exist.

1.2. Regulatory treatment of opex and capex

The regulatory treatment of opex and capex under the NER building blocks framework is illustrated in Figure 1.1.

Figure 1.1: Illustration of the NER building blocks framework



Source: CEPA

Under the NER framework, opex is treated as an expense – customers pay for forecast opex in the year in which it is incurred. As it is assumed there is no time lag between costs and benefits, opex generates no financial return. However, there is the potential for working capital requirements to cover any mismatch between revenues and opex. For this reason, regulatory allowances for asset-light businesses typically include a margin on opex as a way of enabling investors to earn a return to cover their working capital costs. For example,

[2] AER (2017b).

[3] Specifically, we are referring standard control services provided by DNSPs, and prescribed transmission services provided by TNSPs.

Ofwat's regulatory framework for water retailers in England and Wales allows the companies to charge prices that include a net margin above their cost allowance. See Ofwat (2014). The working capital costs needs to cover the risks associated with the companies' liabilities as well as revenues. If their liabilities are seen to be riskier, say from adopting innovative approaches to providing the services, then a higher margin might be required to cover these liabilities. The current regulatory framework does not make a specific allowance for working capital costs and the risks associated with it, rather the AER considers that by assuming all cash flows (besides capex) occur at the end of the year it provides sufficient coverage for working capital. If the proportion of opex related revenue increases (relative to revenue from the regulatory asset base (RAB)) then working capital requirements will need to be reassessed, particularly if there is increased uncertainty around opex.

Capex is treated differently. It is added to the RAB and then remunerated over its asset life via the return *of* capital (depreciation) and the return *on* capital. The latter plays two roles:

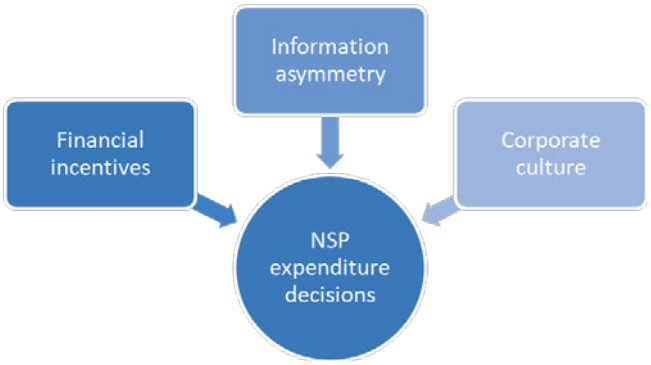
- It compensates the NSP (and, in turn, its investors) for the time delay between when costs are incurred and when they are recovered through charges. By keeping NSPs and investors whole from a net present value (NPV) perspective, the return on capital and return of capital ensure financial capital maintenance.
- It provides a signal to investors regarding the risk-adjusted opportunity cost of any capex that would be incurred during the current regulatory control period.

The AER sets the allowed rate of return based on its assessment of the weighted average cost of capital (WACC) of a 'benchmark efficient entity'. In theory, if the return on capital is set correctly for each NSP – i.e. it exactly matches each NSP's true cost of capital – then investors in that NSP would be indifferent to whether management choose a capex or opex solution, if the outcome is the same. That is, the investors would expect to achieve the same NPV return from opex remunerated in the same year as they would from capex remunerated over its asset life. In the next section we discuss the reasons this assumption may not hold in practice.

1.3. What might cause a capex bias?

NSP decisions to pursue opex or capex solutions may be influenced by a number of drivers, as illustrated in Figure 1.2.

Figure 1.2: Drivers of NSP expenditure decisions



Source: CEPA

Financial incentives could encompass two types of considerations. Firstly, NSPs are likely to target long-term profit maximisation in response to the features of the regulatory framework. This is the Averch-Johnson effect of regulatory economics.[4] It is subject to a number of factors, including:

- How predictable and sustainable efficiency gains are (or are perceived to be) in opex and capex.
- The risk that the regulatory framework would not allow opex/capex to be recovered. For example, whether costs are subject to an efficiency review or potential *ex post* adjustments and, if so, whether this is a one-off or occurs at every determination.
- How the regulatory framework treats any over- or under-spend of opex and capex.
- Whether the allowed return on capital is higher than the NSP's actual cost of capital (one of requirements of the Averch-Johnson effect).[5]

In addition to the financial incentives within the regulatory framework, an NSP might benefit from **information asymmetry** with regard to opex/capex (i.e. over- and under-spends not being equally likely). In particular, it may be (or at least perceived to be) that NSPs are more able to take advantage of information asymmetries in the capex assessment process, rather than for opex.

On a more qualitative level, there may be aspects of NSP **corporate culture** that could contribute to a preference for capex over opex. For example, it has been suggested that some NSPs (or their shareholders) are focussed on growing the RAB or, due to risk aversion, prefer to adopt traditional 'tried-and-tested' solutions.

[4] Averch et al (1962). This was the first identification of the problem of capex bias in utility regulation, demonstrating in a simple model the incentive for a utility both to substitute capex for opex and to expand output under conditions of asymmetric information.

[5] Related to this is the question of consistency in the cost of capital applied across all aspects of the regulatory framework. For example, we note that the EBSS is based on NSPs retaining efficiency benefits for a set period of time and a discount rate that differs from the allowed cost of capital, whereas the CESS has an *ex ante* sharing factor that also relies on a discount rate that differs from the allowed cost of capital.

1.4. A brief summary of previous views and analysis on capex bias

While the implementation of regulatory regimes in other jurisdictions (and sectors) is different from the regulatory framework in the NEM, we consider it useful to look at what regulators, in addition to the AEMC and the AER, have said in regards to the existence of a capex bias. Where possible we have focused on regulators, and periods of time, when the framework was relatively similar to that used in the NEM.

Australia

As part of its Power of Choice review, **the AEMC** investigated whether a capex bias existed. It concluded that under the rules that operated at the time where was "*a clear bias towards capital expenditure in favour of operating expenditure, both in terms of the potential to make profit and certainty about cost recovery*".[6] The AEMC noted that "*under the rules, all actual capital expenditure is rolled into the RAB….[h]owever, for any actual overspend in recurrent operating expenditure, the network business has to seek the regulator's approval that such higher levels of expenditure will be efficient in the future. "*[7]

However, a number of stakeholder have continued to make the case that a capex bias remains in the regulatory framework. For example, this issue was raised part of the Demand Management Incentive Scheme (DMIS) rule change request. The AEMC noted that, with regard to choosing between network solutions and non-network solutions "*distribution businesses have no financial incentive to factor in the broader market benefits from non-network options and they may have limited incentives to trial new non-network options*".[8] This observation led the AEMC to make a rule to introduce the DMIS, which is aimed at incentivising NSPs to adopt efficient demand management alternatives to network investment.

The AER explored the issues around capex bias in developing the DMIS. It noted that the different treatments of opex and capex under the NER building blocks framework could lead to a capex bias if an NSP (or its shareholders):[9]

- Prefer relatively stable long-term cash flows.
- Receive an allowed rate of return on the RAB that is above the NSP's actual cost of capital.
- Value the option to defer capex less than electricity consumers do. This is because NSPs are protected from the risk of overinvestment because current rules protect the value of any investment once it has been added to the RAB.[10]

[6] AEMC (2012a), p. 25.
[7] Ibid, page 8.
[8] AEMC (2015), p. i.
[9] AER (2017c), p. 17.

The AER cited the Institute for Sustainable Futures (ISF) 2017 report[11] reviewing demand management (DM) incentives in the NEM. The report concluded that there were significant barriers to implementing cost effective DM, including that opex was treated less favourably than capex, that there was a bias in favour of network capex rather than non-network opex and future 'option value' was excluded when considering DM solutions.

Concerns about the persistence of a capex bias were also behind a recent rule change request by the Australian Energy Council (AEC).[12] The AEC argued for further changes to the regulatory framework on the basis that, it consider, NSPs to be biased towards:

- capex over opex solutions;
- in-house approaches over outsourced approaches; and
- their own ring-fenced affiliates over third party providers.

The AEMC decided not to make the rule change requested by the AEC, on the basis that changes previously made to the regulatory framework (including those discussed above) needed time to fully take effect. In the sections that follow we comment on the extent to which a capex bias might exist under the current NER framework.

Great Britain

Ofgem, the Great Britain energy regulator, was concerned about a capex bias created when it began to use building blocks in the more modern form we see today (this was during its third electricity distribution price control review in 1998). Frontier's report for the AEMC on Totex Frameworks (Frontier (2017)) provides a brief history of Ofgem's statements on a capex bias and its approach to correct for this. We agree with Frontier that there is no obvious empirical evidence that Ofgem relied upon to demonstrate a capex bias. Rather, we understand that Ofgem's key concerns stemmed from significant divergences in capitalisation policy across the NSPs and that its approach to assessing opex and capex, where benchmarking was used for the former, might lead NSPs to opt for capex in order to appear more efficient. Ofgem did not really begin to address the capex bias until its fifth price control (DPCR5). In DPCR5 it introduced its Information Quality Incentive (IQI) which included both capex and 'direct controllable' opex (this was opex that excluded business support costs). In its preceding price control (DPCR4) it introduced a capex 'sliding scale' incentive that was intended to reduce the incentive on companies to over-forecast and over-invest, but did not include an incentive mechanism for opex. In its most recent price controls, Ofgem a total expenditure (totex) incentive mechanism which treated almost all controllable opex and capex together and capitalised a proportion of the total expenditure.

[10] The AER does have the option to conduct *ex post* reviews of capex, but these are limited to certain instances, such as when an NSP has overspent its capex allowance on projects that do not meet the capex criteria.
[11] Dunstan et al (2017).
[12] AEMC (2012a).

Alongside the totex incentive mechanism Ofgem also shifted to benchmarking totex (although this was not a requirement of using a totex incentive mechanism).[13]

Ofwat, the water regulator for England and Wales, after stakeholders raised concerns about a capex bias, published a discussion paper in 2011 (Ofwat (2011)) which investigated whether there was substance to this claim, whether there was a perception of a bias or whether it was simply a myth. Ofwat undertook consultations with stakeholders, reviewed case studies, modelled financial incentives, and considered non-financial incentives. Ofwat concluded that there was a wide-spread perception of a capex bias across the companies and that acted as a self-fulling belief. It found that companies' perceptions and behaviours reflected their understanding of the incentives, which were complex, and that their reaction was not always what the incentives were designed to achieve. Ofwat's price controls up to the point of the 2011 report had included similar incentive mechanisms to the Efficiency Benefit Sharing Scheme (EBSS) and the Capital Efficiency Sharing Scheme (CESS). Like Ofgem, Ofwat also introduced a totex incentive mechanism in its most recent price controls as it did not consider its separate incentive mechanisms were addressing the capex bias.[14]

An independent review into the water sector in England and Wales, undertaken by David Grey ('**the Grey Review**'),[15] also highlighted a perceived bias toward capital investment. He noted that *"[m]any respondents argue that the companies have an incentive to pursue capital investment schemes, rather than potential alternatives, in order to enjoy the long-term return on the resulting addition to the Regulatory Capital Value (RCV)."*[16] The authors also found that the companies appeared to be very risk adverse and they expressed a concern that they could not rely on not being penalised for inefficiency (due to the use of opex benchmarking) if they choose opex solutions rather than capex solutions. The risk adverse approach, coupled with a dependence on Ofwat to approve investment programmes at a relatively granular level, led companies to always go for investment solutions because it could be defined clearly and approved by the regulator. The Grey Review included an extract from one of the regulated companies, Severn Trent Water, in which they state *"[c]apital investment increases companies' regulatory capital value, on which they earn a return. Operating cost solutions earn no return and higher operating costs lead to a lower comparative efficiency ranking, which adversely affects a company at price reviews. Therefore companies have an incentive to develop capital-based solutions rather than adopting solutions which might be potentially more innovative, or more cost effective, but are operating expenditure based."*[17] While both the authors' and Severn Trent Water's

[13] In DPCR5 Ofgem only used activity level benchmarking, and when it implemented 'totex benchmarking' for DNSPs it placed a significant weight on activity level benchmarking (75% during its initial [fast-track] determinations and 50% during its final [slow track] determinations).
[14] Like Ofgem, Ofwat introduced 'totex benchmarking' that relied on a mix of models that covered totex, and opex plus base capex.
[15] Grey (2011).
[16] Ibid, page 41.
[17] Ibid, page 42.

statement indicate that simply earning a return is a priority and they make no reference to this only being a positive when the actual WACC is higher than the allowed, we note that Ofwat may have 'aimed-up' when it set the WACC.[18]

New York

New York Public Services Commission (PSC) introduced a new framework in 2015 for the electricity utility regulation in New York state 'Reforming the Energy Vision' (**NY REV**). The framework was developed with an objective of "*reducing the total energy bill to New York customers, and fully integrated to ensure optimal resource choices are made.*"[19] The PSC was concerned that there was a capex bias because of the rate of return framework and the fact that the utilities did not earn a return on opex.[20, 21] PSC staff stated that under the existing arrangements "*Utilities do not have a sufficient incentive to use third-party capital to provide service to customers, particularly when this reliance has the effect of increasing their operating expense... utilities will need both mechanisms to recover the expenses they incur to support the developing [DER services] market and opportunities to earn on them.*"[22] In response to stakeholders questioning whether there is an actual financial bias toward capex, as this should only exists where actual returns are expected to exceed allowed returns, the PSC staff note that "*Regardless of whether a capital bias has been demonstrated in the course of ordinary business…[*given the reforms] *utilities should not have a disincentive to use operating resources or third-party assets in lieu of utility capital investment, where the former are more efficient and effective.*"

Summary

Regulators have consistently pointed to the existence of a capex bias without necessarily being able to provide empirical evidence. What is interesting is the consistent view from regulators that companies seek to grow their RAB as this is their primary source of returns. In some cases, the statements appear to focus more on the companies' desire to grow their RABs rather than the theory that investors should only be interested in undertaking capex (instead of an opex solution with a lower expected present value costs) if their actual cost of capital is lower than their allowed. This may be due to an implicit or explicit upward bias in

[18] Ofwat (2011), page 15.
[19] PSC (2015), page 1.
[20] In a white paper on ratemaking and utility business models, PSC's staff noted (PSC (2015), page 3) that "*Utilities' earnings are heavily dependent on their capital expenditures, and the long-term security of their earnings is based on the assumption of a growing or stable sales base. Further, utilities cannot earn a return on operating expenses, except by cutting them. Optimally integrating DERs may, though, require increases in utility operating expenses and decreases in capital spending.*"
[21] While NY State operated a different form of regulation to building blocks, it determines the rate of return in a similar way with the risk of providing the services being compensated by a fair return.
[22] PSC (2015), page 22.

their allowed cost of capital, a recognition of the risk aversion, or other behavioural aspects, of the companies.

Another common theme is that the networks only face an assessment of individual capex projects on their merits once; if approved, capex enters the RAB (unless subject to an *ex post* review). In contrast, opex is reviewed and benchmarked at each price control review. Therefore, by choosing an opex solution, a network may expose itself to being assessed as inefficient.

1.5. Structure of the document

Following this introduction, this report is structured as follows:

- Section 2 sets out how a capex bias could be observed and provides a comparison of historical allowed and actual expenditure;
- Section 3 sets out the financial incentives within the current regulatory framework, commenting the respective incentive strength for capex and opex efficiencies;
- Section 4 provides our findings from modelling the financial incentives;
- Section 5 details other factors that might contribute to a capex bias; and
- Section 6 presents our conclusions.

2. FINANCIAL INCENTIVES IN THE CURRENT FRAMEWORK

In this section we review the financial incentive mechanisms in the current regulatory framework for the NEM.

These include incentives that may influence how NSPs prepare their regulatory proposals (pre-allowance determination incentives) and incentives that may influence their decision-making process once the determination is complete (post-allowance determination incentives). While we describe these incentives separately, NSPs would consider any post-allowance incentives when developing their regulatory proposals.

The two key pre-allowance determination incentives are:

- The AER's approach to assessing expenditure proposals. There is a general financial incentive on NSPs to gain high allowances in order to increase their scope for outperformance and cover the risk of outturn costs being higher than expected. The AER typically relies on benchmarking to assess opex to check/ determine a base-year allowance to roll-forward. As this needs to be reviewed at each price control, this is a repeat game. Capex requires an assessment of a greater range of 'bespoke' projects. As these are one-off assessments, the process is 'done-and-dusted' in a single price control review.
- The WACC allowance. The AER provides detailed guidelines on how it will determine the allowed WACC. The NSPs therefore have reasonable visibility of what the allowed WACC will be and therefore their scope for out/underperformance. This may influence decisions on what capex projects to include in the regulatory proposal. While the WACC is adjusted for the systematic risk faced by the BEE, the business specific risks of a company are still an important consideration for investors, and debt providers. Therefore, these stakeholders may be concerned if companies' management start adopting alternative solutions that may have greater uncertainty around them, even if the overall expected cost is lower.

There are three explicit financial incentive mechanisms that are intended to influence the NSPs during the price control:

- The EBSS. This is designed to equalise the NSPs' incentives throughout the price control to achieve opex efficiencies.
- The CESS. This is designed to equalise the NSPs' incentives throughout the price control to achieve capex efficiencies. It was also intended to help balance the incentives between capex and opex.
- The DMIS. This is designed to encourage NSPs to appropriately consider demand side management solutions as an alternative to capex.

The combined effect of these incentives on NSPs is complex, and the NSPs understanding and interpretation of these mechanisms may not be the response that was intended. Given the complexity, and the interaction with other cultural incentives, it is difficult to conclude how the combined incentives will influence the NSPs' decisions. However, the results of our incentive modelling suggest that it is not clear that the design of the EBSS and CESS do equalise the financial incentives between opex and capex.

The building blocks regulatory regime created by the NEL and NER places a number of financial incentives on the NSPs. These financial incentives have been developed and enhanced over time. Currently the expenditure related incentives on the NSPs include:[23]

- WACC set based on the benchmark efficient entity (BEE).
- The Efficiency Benefit Sharing Scheme (EBSS). Introduced for use in determinations from 2008.
- The Capital Expenditure Sharing Scheme (CESS). Introduced for use in determinations from 2013.
- The Demand Management Incentive Scheme (DMIS). Introduced for use in determinations from April 2018 (including for existing determinations).

These financial incentive mechanisms are intended to work together to ensure that the NSPs choose the most efficient solutions to provide ongoing services to their customers. Before we discuss each of these incentives in turn below, it is important to set out our definitions of **incentive strength** and **sharing factors**:

- **Incentive strength**. In this report, incentive strength refers to the proportion of under-/over- spend that the regulated company retains/ bears relative to the length of a price control. If, for example, an NSP retained only the full amount of an underspend for five years (the current price control length), then the incentive strength would be 100%.
- **Sharing factors**. Sharing factors are either:
    - an estimate of how much of the 'in perpetuity' value of any under-/over-spend a company retains/bears; or
    - a fixed, *ex ante,* factor that applies directly to a company's under-/over-spend. In this case the fixed factor (for the company) will match the incentive strength.

There are two timeframes in which the incentives faced by the NSPs operate:

1. **Pre-allowance determination incentives.** Under the NER, the NSPs are required to submit their revenue proposals,[24] including capex and opex forecasts, to the AER.[25] The AER will then assess the capex and opex forecasts and either accept the NSPs' forecasts or substitute these with their own view. The NSPs have a specific set of incentives, financial and non-financial, in preparing their initial and revised

[23] There are quality requirements placed on the NSPs to help ensure that NSPs do not avoid expenditure required to provide services to their customers.
[24] DNSPs are required to submit building blocks proposals while transmission operators are required to submit revenue proposals. For opex and capex forecasts there is no difference between these aside from their names.
[25] NER 6.5.6, 6.5.7, 6A.6.6 and 6A.6.7.

proposals. These incentives may influence the NSPs' decision to propose capex or opex solutions.

2. **Post-allowance determination incentives.** After the NSPs receive their allowances, they will need to consider how best to respond to the within-price control incentives, such as the CESS and EBSS, when faced with the possibility to out/underperform.

NSPs will almost certainly consider *both* pre-allowance incentives and post-allowance incentives in developing their proposals. For example, as we discuss below, any difference between the incentive strength on opex or capex from the CESS and EBSS will influence the NSPs proposals, although the incentive applies post-allowance.

2.1. Pre-allowance determination incentives

2.1.1. The AER's assessment of forecast expenditure

As a general rule, NSPs have an incentive to obtain an expenditure allowance above their forecast of efficient costs, in order to increase their opportunity to outperform (or provide protection against the downside risk of higher actual costs) and therefore increase investor returns. Part of the AER's role is to assess the NSPs' expenditure forecasts. Both **information asymmetry** and how **the AER approaches the assessment** of the NSPs' expenditure forecasts affect the NSPs' incentives at this stage.

Chapters 6 and 6A of the NER set out the objectives and criteria that the NSPs need to consider when preparing their building block/ revenue proposals. These objectives and criteria are also applied by the AER to determine whether to accept the NSPs' proposed cost forecasts, or to substitute their own assessment. The opex and capex objectives are the same, and they only differ across the DNSPs and TNSPs by reference to the services that are covered under the opex and capex objectives; DNSPs' services are *standard control services* while TNSPs' services are *prescribed transmission services*. The expenditure objectives are to:[26]

(1) meet or manage the expected demand for *standard control services/prescribed transmission services* over that period;

(2) comply with all applicable regulatory obligations or requirements associated with the provision of *standard control services/prescribed transmission services*;

(3) to the extent that there is no applicable regulatory obligation or requirement in relation to:

    (i) the quality, reliability or security of supply of *standard control services/ prescribed transmission services*; or

[26] NER v106 6.5.6(a), 6.5.7(a), 6A.6.6(a), and 6A.6.7(a).

(ii) the reliability or security of the *distribution/transmission system* through the supply of *standard control services/prescribed transmission services*,

to the relevant extent:

(iii) maintain the quality, reliability and security of supply of *standard control services/prescribed transmission services*; and

(iv) maintain the reliability and security of the *distribution/transmission system* through the supply of *standard control services/prescribed transmission services*; and

(4) maintain the safety of the *distribution/transmission system* through the supply of *standard control services/prescribed transmission services*.

The forecast operating and capital expenditure criteria are:

(1) the efficient costs of achieving the *[operating or capital] expenditure objectives*;

(2) the costs that a prudent operator would require to achieve the *[operating or capital] expenditure objectives*; and

(3) a realistic expectation of the demand forecast and cost inputs required to achieve the *[operating or capital] expenditure objectives*.

The factors that the AER must have regard to in assessing opex and capex are also almost identical. In particular, the AER must take account of:[27]

- its most recent annual benchmarking report which covers both opex and capex, and total factor productivity. The extent of the benchmarking approach differs between TNSPs and DNSPs, with an additional econometric benchmarking approach undertaken for DNSP opex.
- The NSP's historical performance against its allowances.
- The substitution possibilities between opex and capex.
- The extent to which the NSPs have considered non-network opex.

While the NER set similar objectives and obligations on the NSPs' expenditure forecasts and the AER's assessment of them, in practice the mechanics of developing the forecasts and assessing them are quite different. This may well impact the incentives for the NSPs.

For opex, the AER typically relies on a revealed cost base-step-trend assessment approach which relies on the assumption that opex is relatively consistent overtime.[28] The AER determines efficient opex in a base year, then applies step changes for opex not reflected in

[27] NER v106 6.5.6(e), 6.5.7(e), 6A.6.6(e) and 6A.6.7(e).

[28] The base-step-trend approach is a top-down approach and the AER also use bottom-up assessments to support its base-step-trend analysis. However, if it substitutes an NSP's forecast it typically uses the base-step-trend approach.

the base year and finally trends this forecast using input costs, productivity and output growth. The AER uses benchmarking and other bottom-up approaches to determine efficient costs in the base year.

Because of this relatively mechanistic approach to determining the opex allowance, the NSPs will understand that revealing their efficient opex levels will affect their allowances in future regulatory periods. However, the only way for the NSPs to profit from opex outperformance is to achieve efficiencies above their allowance.

Capex is a different story. While an NSP may seek to plan capex in a relatively smooth way, the capex profile is still heavily driven by the need to replace assets and the changes in demand across its network. While revealed capex is a useful input into the AER's assessment of future capex, and the AER can assess this alongside output measures, unit cost, and asset age/ health profiles, revealed capex does not play the same role as revealed opex. In addition, it is more difficult for the AER to independently assess the prudency and efficiency of specific capex projects, particularly for load related projects. This is because these often involve bespoke solutions that are not readily comparable across NSPs and therefore rely on (subjective) judgement around (a) the specific need for the capex (b) appropriateness of the solution, and (c) whether the expenditure associated with the proposed solution is efficient.

This means that there are likely to be greater **information asymmetries** around forecast capex compared to forecast opex, or at least longer-term asymmetries as opex will be revealed each five-year period.

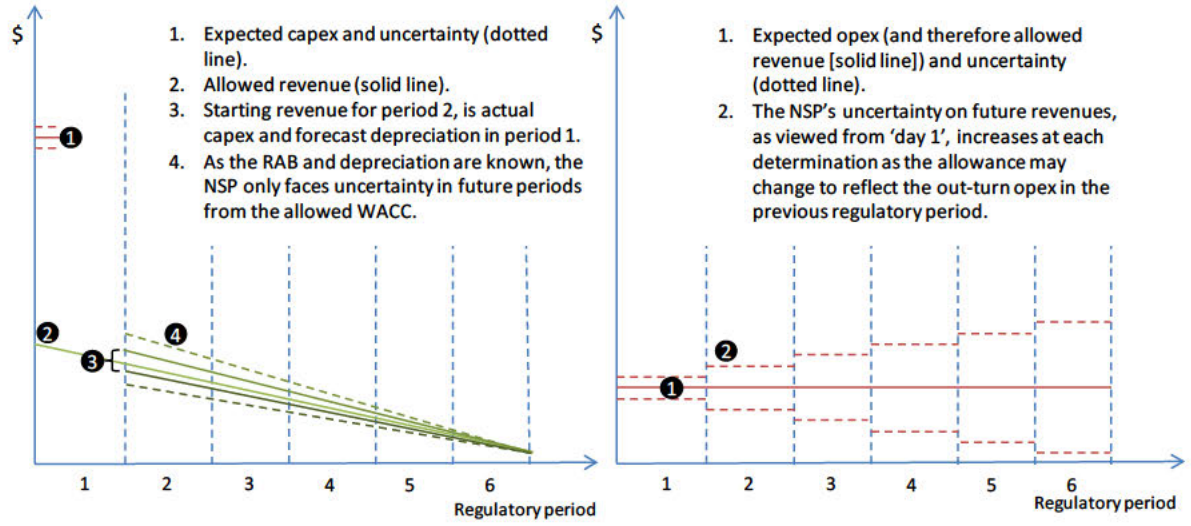
Does this mean that there is a capex bias? This is not obviously the case, assuming that the NSPs' expected actual WACC is equal to the allowed WACC, However, if we consider an example where an NSP is considering whether to propose a capex solution *or* an equally efficient opex solution which achieves the same outcome:

- There is greater uncertainty around the future allowances for an opex project.
    - If the NSP's approach to using opex solutions is out of sync with other NSPs, then it may be considered to be inefficient in the benchmarking. It may be able to request an operating environment factor; however this would require the NSP to prove why it should get an uplift for these costs. It would be subject to this for the duration of the opex solution.
    - The opex solution is exposed to input price and productivity changes that may be above or below the AER's expectation.
- For a capex project, the NSP is exposed to the risk/reward that its future actual cost of capital may be higher/lower than the allowed level.
- There is also a potential behavioural bias to capex solutions that may be due to risk aversion and/or that favours established engineering approaches.

- The AER also has the ability to conduct an *ex post* review of capex, however this is only when an NSP overspends against its allowance. While this encourages NSPs to underspend to avoid this review, it also may create an incentive for them to seek higher capex allowances to provide *headroom* to avoid the review.

We illustrate the dilemma facing NSP management when choosing a capex or opex capex solution in Figure 3.1 below. Without losing the generality of the example, we assume that the opex solution delivers the same outcomes as the capex solution, both solutions result in the same PV costs, the NSP's actual WACC is equal to the allowed, and the EBSS and CESS do not apply.

Figure 2.1: Difference between revenue flows (LHS = capex, RHS = opex)



Source: CEPA

On the **left-hand side chart**, we have the example of an investment in capex in the first year of the first price control period and the resulting revenue flows to the NSP. The NSP faces uncertainty around the actual capex (illustrated by the dotted lines) due to design, input price changes, etc. Once the capex is added to the RAB the NSP is likely to receive relatively stable revenue flows for the rest of the assets useful life – as the depreciation is fixed and therefore the remaining RAB at each period is known. The only uncertainty stems from the return on capital as the WACC is reset at each price control (illustrated by the dotted lines). As the RAB decreases over the life of the asset, the share of revenue subject to this uncertainty decreases. If there is an overspend (the top solid line) then the NSPs RAB will be increased at the start of the second price control period to reflect this (as actual capex and forecast depreciation are used to rollforward the RAB). An underspend (bottom solid line) will result in a lower RAB.

On the **right-hand side chart**, we have an example of an opex solution being employed. Revenue is equal to opex.[29] Because the AER reassess the opex allowance at each price control the NSP will face uncertainty from changes in input prices (e.g., wages), required volumes (e.g., hours), and whether any overspend will be allowed by the AER or if its allowance will be adjusted down for any underspend. Therefore, the longer the opex solution lasts for the greater the uncertainty will be at the point at which it is implemented.

Overall, we consider that NSPs have a financial incentive to increase both their capex and opex forecasts in order to improve their scope for outperformance, although there may be reputational incentives that offsets this to some extent. Due to the differences in the assessment of the expenditure types, NSPs may find it more attractive to put forward a capex solution rather than an opex solution. This does not prevent an NSP from choosing an opex solution after receiving its determination. However, as we discuss below, this depends on the incentives *during* the price control.

2.1.2. WACC allowance – Benchmark efficient entity (BEE)

The National Electricity Rules (NER) specify that:

> *"The allowed rate of return objective is that the rate of return for a …[NSP]… is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the …[NSP]… in respect of the provision of standard control services (the allowed rate of return objective)."*[30]

As the NER requires that the allowed rate of return (the Weighted Average Cost of Capital (WACC)) is set for the NSPs on the basis of a BEE, there is scope for the NSPs to out/underperform against the allowed WACC.

If an NSP considers that it can outperform the allowed WACC (i.e., achieve financing at a lower rate or that the allowed cost of equity is higher than required) then it may favour capex solutions as this will increase the RAB. If it considers that it will underperform against the allowed WACC then it may reduce capex and/or favour opex.

The NSP will retain/ bear all of the difference between its actual and allowed cost of capital.

The AER's Rate of Return Guidelines, which are to become binding guidelines,[31] are published in advance of the AER making a determination. Therefore, the NSPs are aware of the approach to estimating the allowed cost of capital and will be able to estimate what

[29] The NSP only earns a return it if can outperform its opex allowance and loses money if it underperforms against its allowance.
[30] NER, v106, clauses 6.5.2(c) and 6A.6.2(c).
[31] Draft legislation to affect this decision by COAG (Statutes Amendment (National Energy Laws) (Binding Rate of Return Instrument) Bill 2018, v08, 20 February 2018.

their allowed cost of capital will be at the time of putting together their building blocks/revenue proposals.

At this stage, the NSPs will assess whether their expected actual cost of capital is likely to be above or below the allowance:

- If the NSP believes it can ***outperform*** the allowed cost of capital then it may have a financial incentive, to the extent a trade-off is possible, to propose capex instead of opex.
- If the NSP expects to ***underperform*** the allowed cost of capital then it may have a financial incentive, to the extent a trade-off is possible, to propose opex instead of capex. However, as noted above, in this case this means increasing its opex forecast which the AER will assess using a base-step-trend approach.

After the allowed WACC for an NSP has been announced, its decisions during the price control will be based on the incentives within the framework.

A further financial incentive that may influence an NSP's expenditure decisions is likely to be the desire to minimise the NSP's exposure to systematic risk. An NSP's cost of capital would increase with greater exposure to systematic risk via the beta component of the cost of equity, so the NSP is incentivised to minimise exposure to systematic risk in order to improve its chances of outperforming the allowed rate of return. For example, if an NSP's main source of systematic risk relates to opex cash flows (e.g. labour costs), it may favour capex solutions over projects with substantial opex components, as the latter would tend to increase its exposure to systematic risk. It is also important to consider how company-specific risk may affect the incentives. While the investor can diversify away company-specific risk, and this is an underlying assumption of the cost of capital, investors should still be concerned that companies' management appropriately manages business risk. If the company engages in more 'risky' solutions (for example, moving away from more tried-and-tested capex solutions) this may increase the volatility around the investor's expected return. In addition, it is also important to bear in mind that debt providers are concerned about business-specific risk. Debt providers, unlike equity investors, have no upside on their expected yield but face the downside risk that their yield may be lower if a project or company fails or underperforms. Therefore, debt providers may require a higher promised return to reflect the companies' specific risk.

2.2. Post-allowance determination incentives

In this section, we discuss the incentives that apply once an NSP has received its revenue determination.

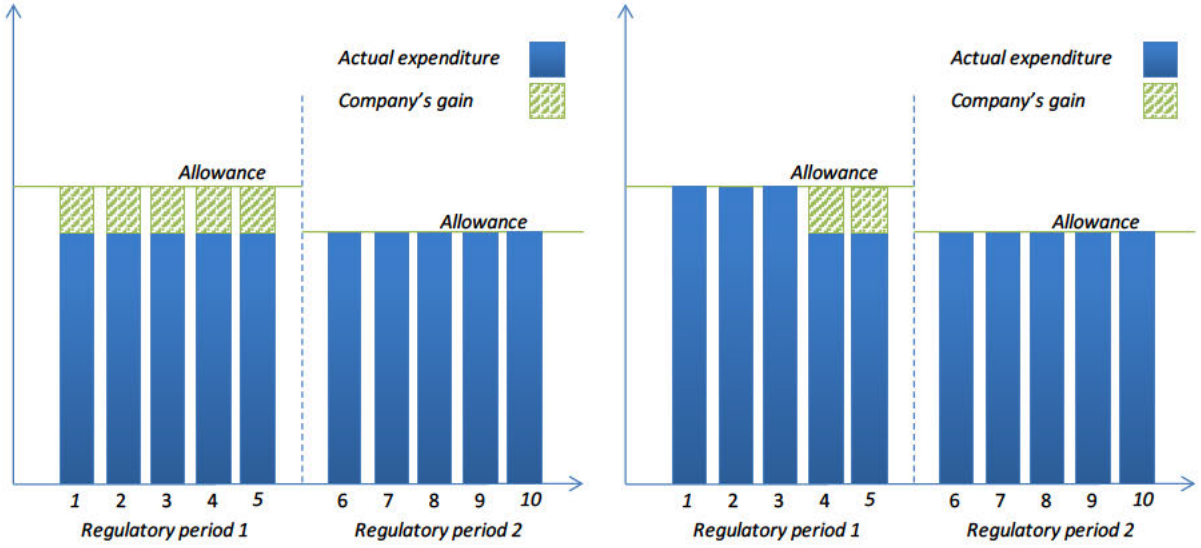
2.2.1. Efficiency Benefit Sharing Scheme (EBSS)[32]

The EBSS only applies to opex. The EBSS was introduced to solve two incentive issues in the regulatory framework, that are particularly prominent when using a base-step-trend approach:[33]

1. NSPs had an incentive to increase costs in the base year, in order to increase allowances for the subsequent regulatory period.
2. NSPs' incentives to make ongoing efficiency savings decreased as the regulatory period progressed, towards the next period's base year. This is because the NSP would only retain savings made up to the base year.[34]

The latter issue is illustrated in Figure 3.2 below. In the LHS figure, if the NSP makes a recurring saving in Year 1, then it keeps the gains for five years before the allowance is reset to the new efficient opex level. In the RHS figure, if the NSP makes a saving in Year 4, then it only keeps it for two years before the allowance is reset for the next control period.

Figure 2.2: Incentive strength over time (without EBSS)



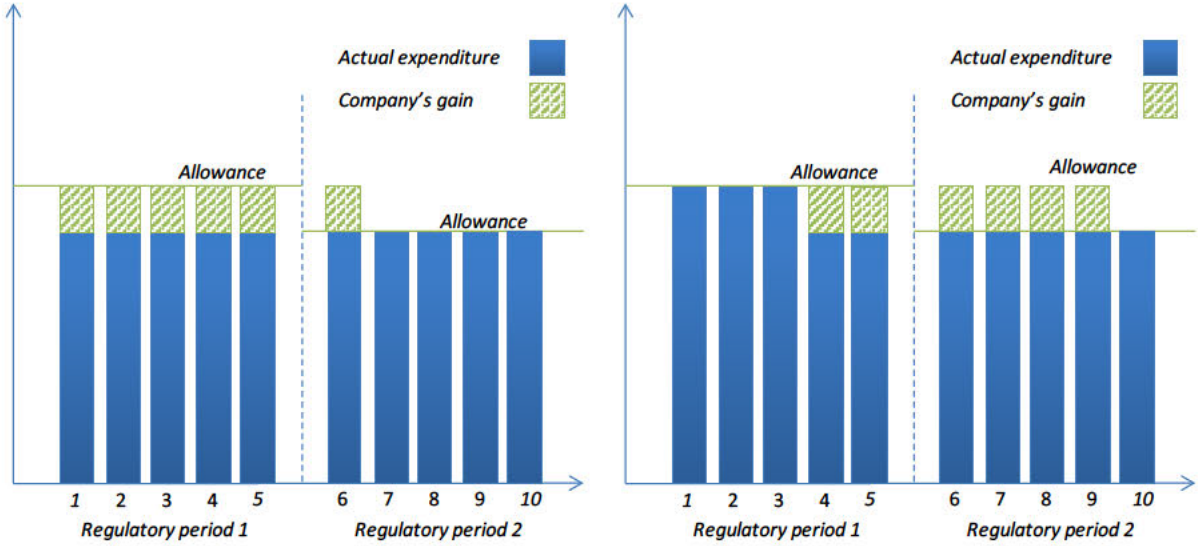
Source: CEPA

The EBSS allows the NSP to keep any recurring (permanent) savings for a period of six years regardless of when the saving is made.[35] This is illustrated in Figure 3.3 below. The LHS figure shows that if the NSP makes a recurring saving in Year 1, it will retain this saving for

[32] The EBSS was first introduced in 2008 and reviewed in 2013. The EBSS was largely unchanged following the 2013 review.
[33] This approach relies on revealed costs in the base year as a starting point, adjusting this for any one-off expenditure, then adding an 'steps' for any additional opex not reflected in the base year, and then applying a 'trend' for productivity, output and input price changes.
[34] AER (2013b), page 6.
[35] The mechanics of the EBSS can be found in AER (2013b).

six years. The RHS figure shows that the NSP will retain a saving made in Year 4 for six years, until Year 9.

Figure 2.3: Incentive strength over time with the EBSS



Source: CEPA

The incentive is symmetric, in that if the NSPs as a recurring overspend it has to bear the costs for six years. The **incentive strength** for permanent savings/ over-spends is over 100% as the NSP will retain/ bear the savings/ over-spends for longer than a single regulatory period. The retention period of the savings is the incentive strength of the EBSS. Temporary savings are treated differently. Temporary underspends or overspends are neutralised through later adjustments to customer bills (aside from the time value of money). This means that NSPs are not incentivised to exploit short term opportunities to cut costs or to prevent possible short term higher costs.

In addition to the incentive strength, regulators also focus on the **sharing factor** (or rate). The AER relies on a savings-in-perpetuity calculation to determine its estimate of the sharing rate. The AER's opex sharing rate is based on companies retaining the efficiency savings for six years with a real discount rate of 6%. This means that if a company makes a recurring $10 saving it retains that benefit for six years. After discounting, the recurring saving is equal to $52. The total 'savings' in perpetuity are $167,[36] therefore the consumers share is $115 (or approximately 69%). The headline sharing factor for the NSPs is therefore approximately 30% (or 31%), i.e., the NSPs retains (gains) 30% of under- (over-)spends while consumers receive (bear) 70% of under- (over-)spends.

The sharing factor estimate is dependent on the regulator placing 100% weight on the revealed costs in setting allowances during the next period and into the foreseeable future. If the regulator uses benchmarking or makes an independent assessment to set allowance

[36] $167 = $10/6%.

for the next regulatory period, i.e., placing less weight on the revealed costs, then it could be argued that consumers would benefit from efficiency gains without additionally rewarding the company.[37]

Therefore, there are two important takeaways from how the EBSS is works:

- The 30% sharing factor does not reflect the financial incentive on the NSPs for under-/over-spending on opex. Rather, this is determined by the retention of under-/over-spends for six years.
- The use of exogenous forecasts (i.e., benchmarking) rather than a base-step-trend approach changes the incentive properties.

2.2.2. Capital Expenditure Sharing Scheme (CESS)

The CESS only applies to capex.[38] It was introduced in 2013 to work alongside the EBSS, primarily to equalise the incentive to make capex savings over the regulatory period, but also to avoid inefficient substitution between opex and capex.[39] Like opex, the NSPs' incentive to underspend (or avoid overspends) on capex diminishes as the price control progresses. This is because the RAB is adjusted for actual capex when rolled forward at the start of the next price control. Therefore, any benefit – the difference between forecast and actual depreciation and the difference between forecast and actual return on RAB – from underspending capex at the start of the period is retained for five years, while underspend later in the period is retained for a shorter time. The AER cited three key reasons why the declining incentive may be an issue:

1. As the incentive to underspend (or avoiding overspending) at the end of the period is low, the NSPs may not be disciplined in their approach to capex towards the end of the period.
2. It could distort decisions on whether opex or capex solutions should be used. This is because the opex incentive over the period is equalised through the EBSS.
3. Capex may be less efficient if entered into at the end of the period. The AER cite concern that projects delayed until the end of the period may create a capacity issue requiring the use of more external contractors and/ or less cost-effective contracts.[40]

Because of the differences between how capex and opex are remunerated, the CESS mechanism needs to be different from the EBSS. Rather than setting a savings retention period, the AER rely on the in-perpetuity calculation from the EBSS to set, *ex ante*, both the **incentive strength** and **sharing factor** for the CESS at 30%. The 30% factor is applied to any

[37] The AER illustrate this in Annex B ("How the EBSS interacts with an exogenous forecasting approach") of, AER (2013b).
[38] NER v106 clause 6A.6.5A.
[39] AER (2013a), page 10.
[40] AER (2013a), pages 24-25.

under-/over-spend across the entire regulatory period, with a discount factor applied to convert the differences between actual and forecast capex into a net present value (NPV).[41] It is important to note that the sharing factor is applied pre-tax, therefore the NSPs will pay tax on any retained underspend which reduces their overall benefits.[42] The NSPs also pay tax on opex savings retained.

Alongside the *ex ante* sharing factor, the AER (in most circumstances) rolls forward the RAB using actual capex and forecast depreciation. The AER stated that the use of actual depreciation would lead to higher powered incentives than the intended 30%.[43]

In addition, unlike opex, the AER is able to scrutinise an NSP's capex on an *ex post* basis – albeit under certain conditions only. Where it deems that some capex may have been inefficient or imprudent, it can remove this capex from the RAB and reverse any penalty/ reward provided by the CESS.

2.2.3. Demand Management Incentive Scheme (DMIS)

In August 2015, the AEMC published its final rule determination setting out revised arrangements to incentivise DNSPs to adopt demand management solutions instead of network projects, where this would be more efficient.[44] (The DMIS and demand management innovation allowance (DMIA) only apply to DNSPs.) The rule change was in response to stakeholder concerns that under the prevailing regulatory framework, DNSPs were biased towards network investment over alternative options. The rule change established two parts to the demand management incentive framework:

i. The **demand management incentive scheme** (DMIS), which provides DNSPs with the opportunity to earn financial rewards for implementing efficient non-network projects that deliver net cost savings to consumers.

ii. The **demand management innovation allowance** (DMIA) which makes funding available to DNSPs for research and development of non-network solutions with the potential to reduce long term network costs.

While the DMIA may over time increase the non-network solutions available to or recognised by DNSPs, we do not consider that it would impact a particular capex/opex trade-off decision at a given point in time. Therefore, we focus here on the DMIS.

In December 2017, the AER published its final design for the DMIS.[45] For each DNSP, the DMIS will be implemented according to the steps outlined below:

[41] AER (2013a), Attachment B provides worked examples.
[42] Similarly there tax will be reduced for overspends.
[43] Economic Insights (2012).
[44] AEMC (2015).
[45] AER (2017c).

i. Through its distribution determination, the AER will set out how (if at all) the scheme will apply to the DNSP during its regulatory control period.

ii. DNSP identifies **eligible projects**, which must: be the preferred option to meet an identified need on the distribution network; must have a positive NPV when assessed against the status quo (unless for reliability corrective action); and have been assessed as the preferred option through either the RIT-D or the minimum project evaluation requirements[46]. A project becomes **committed** when the DNSP enters into a contract to procure the required DM from a third party, or internal approval is granted for self-provision of the DM project.[47]

iii. DNSP calculates the **project incentive** for committed projects. The project incentive is capped at the lower of: (a) the expected present value of the project's DM costs (net of subsidies) multiplied by the **cost multiplier** or (b) the expected present value of the project's net benefit (calculated through a cost-benefit analysis).

The cost multiplier under the current DMIS is **50 per cent**. While the AER may vary this, the multiplier prevailing at the time an eligible project becomes a committed project will still continue to apply for that project.

iv. DNSP prepares and submits an annual DM **compliance report** to the AER, setting out the details of both committed and eligible projects.

v. Based on the compliance report, the AER determines the **total financial incentive** available to the DNSP for each year of its regulatory control period. This includes adjustments for projects previously committed, but not fully implemented. The total financial incentive that a DNSP may accrue across all committed projects is capped at 1 per cent of their allowed annual revenue for that year.

vi. The total financial incentive for year *t-2* will then be included in the DNSP's total revenue allowance for year *t*.

The DMIS can operate as both a pre- and post-allowance determination incentive.

2.3. Summary

The discussion above highlights the complexity of the incentives faced by NSPs. Consequently, there is a risk that when combined, the difference incentives may not produce their intended outcomes. Each NSP needs to work out how it responds to these

[46] As set out in the AER's final DMIS design, clause 2.2.1.

[47] The DMIS is neutral on whether the DM project is procured from a third-party or implemented in-house, provided that this is consistent with other aspects of the regulatory framework. For example, this would include the ring-fencing guideline and other restrictions, such as limitations on whether behind-the-meter assets can be included in a DNSP's RAB.

incentives and their understanding may differ from what the designers of the incentives intended.

We provide a high-level summary of how the factors above may influence the financial decisions of NSPs in Table 3.1 below.

Table 3.1: Summary of financial incentives

Factor/ incentive mechanism	Influences
Expenditure assessment	• Broad incentive to seek high expenditure allowances to create a greater chance of outperformance or cover risks from higher outturn costs. • Lower future opex allowances from revealed efficiency gains. • Capex assessment typically 'one-off' based on merits of individual projects.
WACC	• Incentive to outperform a broad BEE target WACC allowance. • More 'risky' innovative or alternative opex solutions may increase volatility around the expected return.
EBSS	• Equalises the opex incentive over the regulatory period. • Strong financial incentive to decrease opex, although this leads to a reduction in base opex.
CESS	• Equalises the capex incentive over the regulatory period. • Ex ante proportion of over/underspend retained by the NSP.
DMIS	• Specific revenue reward to encourage NSPs to consider demand management solutions. • Can influence NSP decisions pre-allowance and post-allowance.

We cannot model an NSP's *response* to these incentives. However, in the following sections, firstly, we review how we might measure the NSPs response from available data and secondly, we model the *interaction* of the incentives to determine whether there might be an overall financial incentive on the NSPs to prefer opex or capex solutions.

3. OBSERVABLE INDICATORS AND A REVIEW OF ACTUAL VERSUS ALLOWED EXPENDITURE

In this section we set out the ways that a capex bias might be observed. We identify four potential indicators:

- Changes in opex and capex over time, with an increasing capex to opex ratio indicating a bias.
- Out/ under performance against the incentives.
- Evidence that NSPs have chosen a less optimal capex solution over an opex solution.
- Evidence that NSPs are not considering opex solutions.

In this section we have focused on the first two of these indicators, with the remaining two considered in Section 5. However, in relation to all these indicators there is a lack of a counterfactual (bias free) to compare with. This limits the usefulness of any comparisons.

In relation to the first indicator, it is difficult to disentangle the effects of incentives from other factors. These include: changes in the DNSPs capitalisation policies; changing customer requirements; changing technology; changes in the NEM and introduction of different incentive mechanisms; and changing input costs. Because of these reasons, it is difficult to review a long consistent time series for the NSPs. Therefore, we do not consider that we can draw concrete conclusions from the trends in the capex to opex ratio.

In relation to the second indicator, using RIN data from the DNSPs for their most recently completed regulatory determinations,[48] we find that over the most recently completed price control DNSPs generally outperformed their capex allowances (only three underperformed), but only four outperformed their opex allowances. However, because forecast demand did not eventuate augmentation capex was not required and therefore the capex outperformance is likely to be higher than a counterfactual where the demand did eventuate. All the TNSPs outperformed both opex and capex, however their capex outperformance was significantly higher.

Given the lack of a counterfactual and our inability to disentangle the different factors influencing the NSPs' spending, we cannot conclude from this evidence either way whether there is a capex bias or not.

3.1. Indicators

In this section we set out the ways that a capex bias might be observed. We identified four potential indicators:

1. Relative changes in opex and capex over time.
2. Out/ under performance against the incentives.
3. Evidence that NSPs have chosen a less optimal capex solution over an opex solution.
4. Evidence that NSPs are not considering opex solutions.[49]

The first two indicators can be quantitatively observed, while the latter two are typically qualitative and rely on judgement as to whether the NSPs are considering opex solutions appropriately. We discuss these latter two indicators in more detail under corporate and behavioural biases in Section 5.

[48] 2009/10 to 2013/14 for the NSW and ACT and 2011 to 2015 for QLD, SA and VIC.
[49] These are similar to those identified in Ofwat (2011).

One issue with the first two indicators is that there is no counterfactual which we can compare them against. There is also a myriad of factors that could influence the observed indicators – these include changes in demand, input price changes and data limitations, among others.

In the case of the last two factors, it is conceivable that project-specific counterfactuals could be developed, in order to assess whether a more optimal opex solution exists. This is similar to the approach taken by the 2017 IFS study.[50] Given the need for engineering judgements and project-specific analysis, we have not undertaken a similar assessment for this paper. However, we note the analysis reported by the AER as part of the ongoing RIT application guidelines review.

3.1.1. Capex to opex ratios

In relation to the first indicator, a capex bias could potentially be indicated by increasing capex relative to opex. However, there is limited timeseries data available for the NEM NSPs with a consistent regulatory framework and it is difficult to disentangle the effects of incentives from other factors. These include:

- changes in capitalisation policies;
- changing customer requirements, such as demand growth/ reductions;
- changing technology;
- changes in the NEM and introduction of different incentive mechanisms; and
- changing input costs.

For example, the available data for the most recently completed DNSPs price controls (2009-2015[51]) covers a period where actual demand was much lower than forecast and therefore augmentation capex fell away significantly.

For the reasons outlined above, particularly changes in the regulatory framework, it is difficult to establish a long, consistent time series for the NSPs. Therefore, we cannot draw any conclusions from this indicator.

3.2. Out/underperformance – actual versus allowed expenditure

A number of interpretations could be drawn from out/underperformance:

[50] IFS (2017).

[51] For ACT and NSW this is the 2009/10 to 2013/14 period, 2010/11 to 2014/15 period for QLD, and 2011 to 2015 period for VIC and SA. For TasNetworks the average is from 2013 to 2015 only and category RIN data for Ergon and Energex was not available on the AER's website for 2013/14.

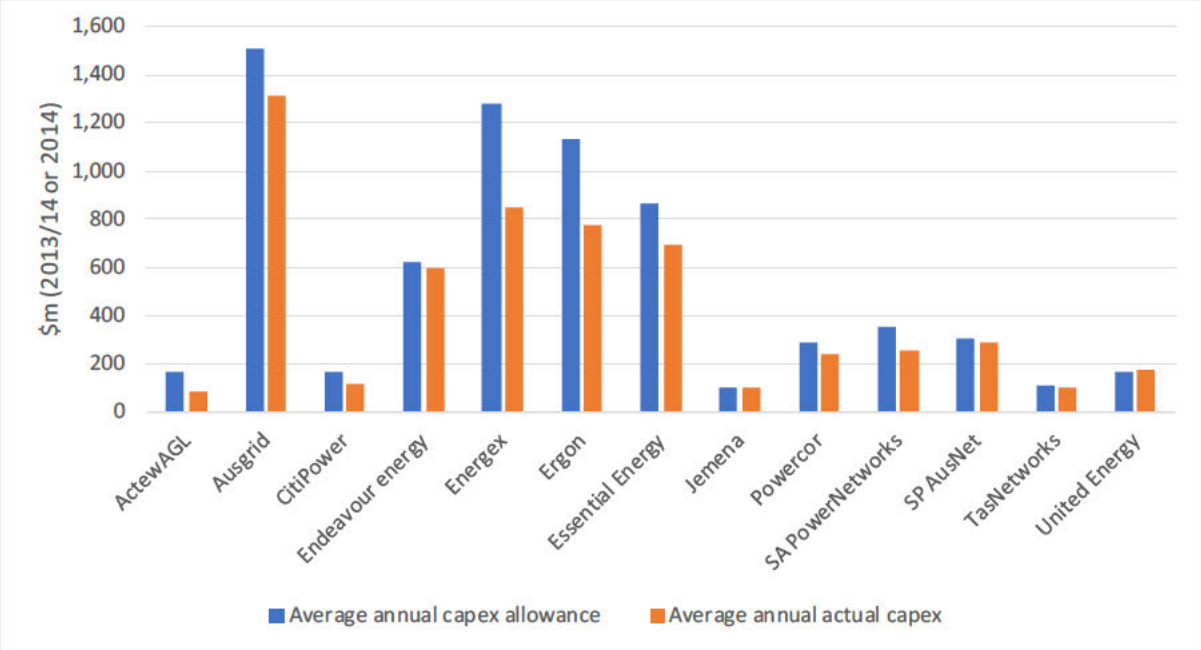
- Relatively high levels of capex outperformance compared to opex could indicate information asymmetries i.e., NSPs putting forward additional capex as it is relatively harder to assess (see our discussion on this in Section 3.1.1).
- Relatively high/ low levels of capex outperformance could be driven by demand being lower/ higher than forecast.

We present evidence from NSPs' actual versus allowed expenditure for their most recently completed price controls. The data on their allowed expenditure was derived from the AER's final decisions, corrected for any successful appeal, and the data on actual expenditure was sourced from the category Regulatory Information Notices (RINs). The EBSS was in place for the all of these price controls, however the CESS was not yet introduced.

3.2.1. Distribution NSPs

Figure 2.1 below sets out the DNSPs' average annual allowed and actual net capex (gross capex less customer contributions) for each DNPS's most recently completed price control period. We can see that the majority of DNSPs, apart from Jemena and United Energy, outperformed their capex allowances.

Figure 3.1: DNSP total average annual real allowed and actual net capex[52]



Source: CEPA analysis of AER determinations and annual RINs

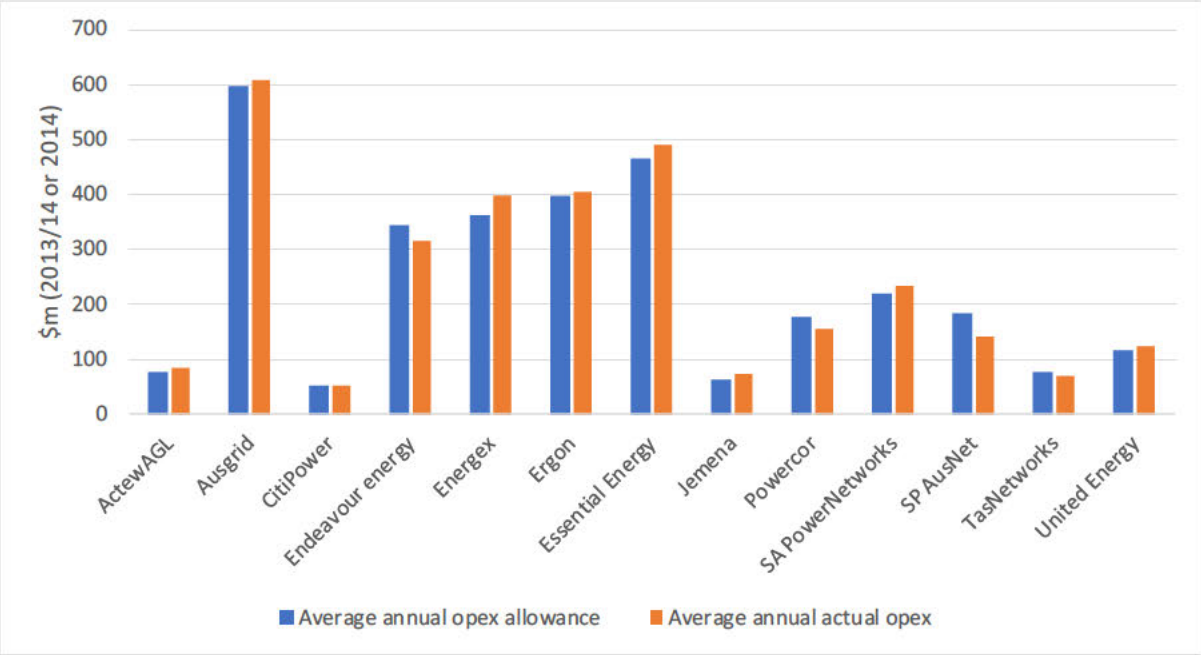
The capex underspending was largely driven by:[53]

[52] For ACT and NSW this is the 2009/10 to 2013/14 period, 2010/11 to 2014/15 period for QLD, and 2011 to 2015 period for VIC and SA. For TasNetworks the average is from 2013 to 2015 only and category RIN data for Ergon and Energex was not available on the AER's website for 2013/14.
[53] AER (2015b), page 22.

- Lower actual demand than forecast, therefore augmentation projects were deferred or avoided.
- DNSPs actively seeking to reduce the need for capex.
- Improvements in risk management that led to a reduced volume of works.

Figure 2.2 below sets out the DNSPs' average annual allowed and actual controllable opex. In contrast to capex, the majority of DNSPs underperformed against their opex allowances.

Figure 3.2: DNSP total average annual real allowed and actual opex[54]



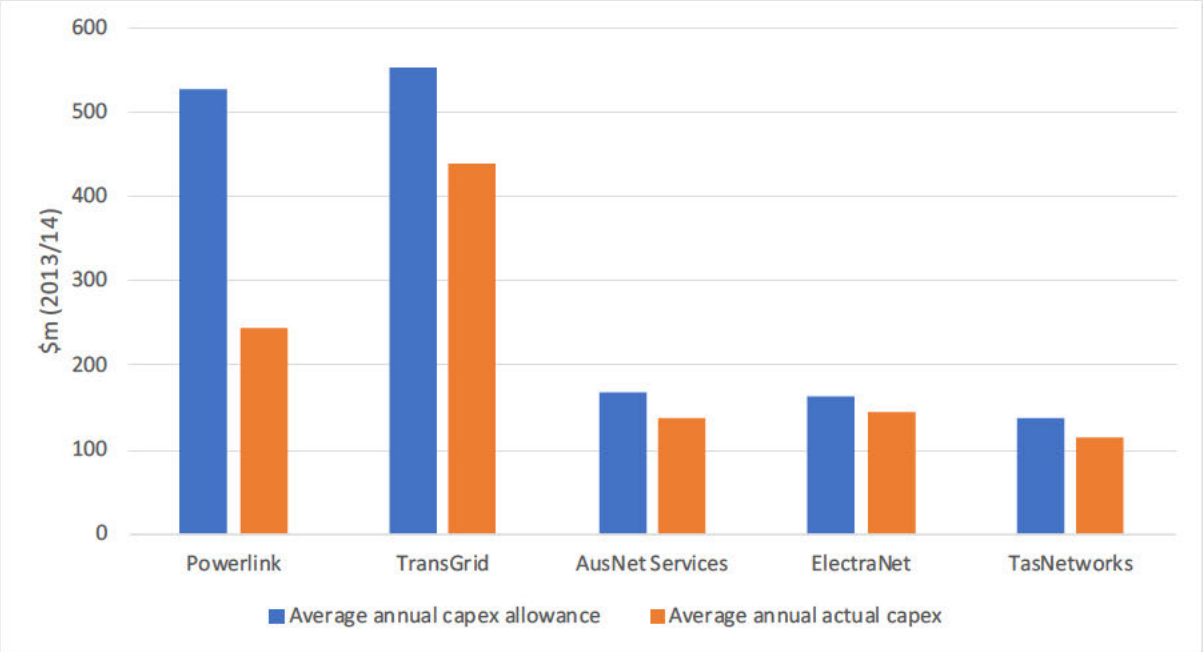
Source: CEPA analysis of AER determinations and annual RINs

3.2.2. Transmission NSPs

Figure 2.3 below sets out the TNSPs' average annual allowed and actual net capex (gross capex less customer contributions) for each TNPS's most recently completed, mostly complete, price control period (we have included ElectraNet's current price control as there is four years of data available). We can see that the all the TNSPs outperformed (or are outperforming) their capex allowances.

[54] For ACT and NSW this is the 2009/10 to 2013/14 period, 2010/11 to 2014/15 period for QLD and SA, and 2011 to 2015 period for VIC. For TasNetworks the average is from 2013 to 2015 only and category RIN data for Ergon and Energex was not available on the AER's website for 2013/14. For Ergon and Energex we have removed the solar feed-in-tariff payments.

Figure 3.3: TNSP total average annual real allowed and actual net capex[55]



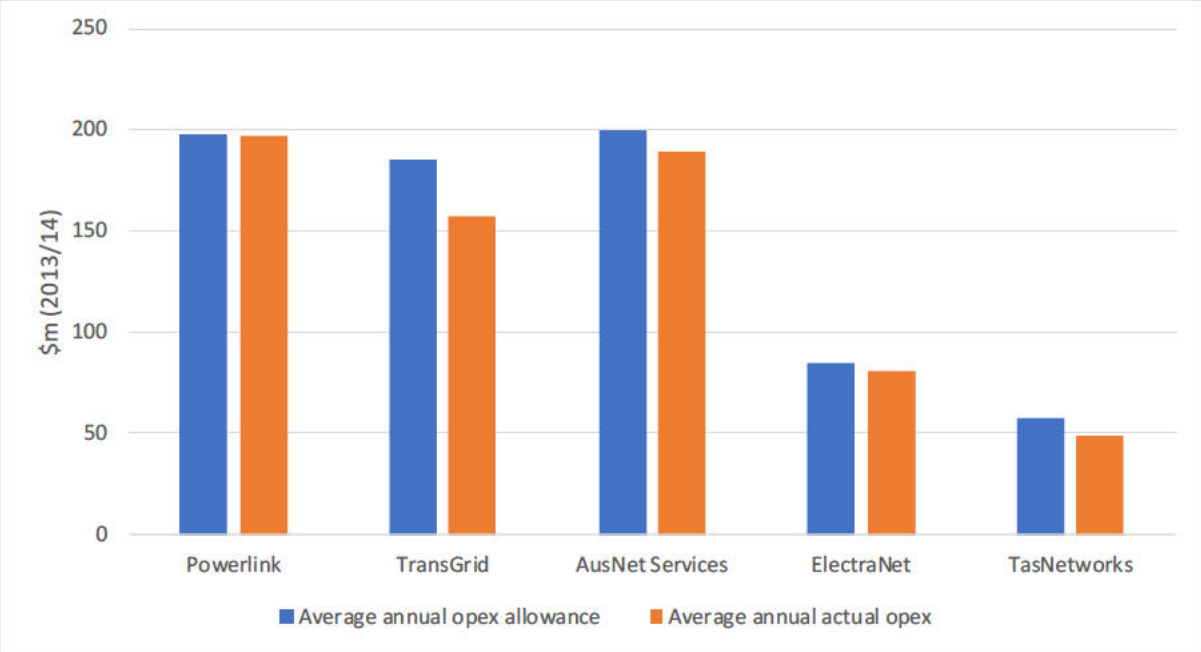
Source: CEPA analysis of AER determinations and annual RINs

The TransGrid and TasNetworks price control periods covered in the figure includes the lower outturn demand period, the other TNSPs price control periods are occurring after demand had dropped compared to forecasts.[56]

Figure 2.4 below sets out the TNSPs' average annual allowed and actual controllable opex. The TNSPs also outperformed their opex allowances, although to a lesser extent than their capex outperformance.

[55] The price controls covered are: Powerlink 2012/13 to 2016/17; TransGrid 2009/10 to 2013/14; AusNet Services 2014/15 to 2016/17; ElectraNet 2013/14 to 2016/17; and TasNetworks 2009/10 to 2013/14.
[56] Overall NEM electricity consumption began falling from around 2009/10.

Figure 3.4: TNSP total average annual real allowed and actual opex[57, 58]



Source: CEPA analysis of AER determinations and annual RINs

3.3. Evidence of inefficient investment decisions, or insufficient consideration of opex solutions

In principle, the RIT process could provide a potential source of information to assess whether capex and opex alternatives to meet identified network needs are being appropriately considered. In particular, the NER set out requirements for the RIT-D process to include screening of potential non-network options. Specifically, a RIT-D proponent must either:

- publish a non-network options report, to assist non-network service providers to propose alternative options for consideration in the RIT-D; or
- if the proponent determines that non-network options cannot form part of a credible option to address the identified need, they must publish a notice, setting out their reasoning.

While not subject to the same provisions as the RIT-D, the RIT-T process still requires TNSPs to consult on credible options.

[57] The price controls covered are: Powerlink 2012/13 to 2016/17; TransGrid 2009/10 to 2013/14; AusNet Services 2014/15 to 2016/17; ElectraNet 2013/14 to 2016/17; and TasNetworks 2009/10 to 2013/14.
[58] This includes network support costs, debt raising costs and movements in provisions. We note that the AER's presentation of out/underperformance in its determinations excludes these costs.

We have not independently reviewed the analysis of non-network options undertaken by NSPs in line with these requirements. However, we note below the AER's analysis as part of the ongoing RIT application guidelines review.

To date, the RIT-D has been applied 17 times, with 11 of the RIT-D's including publication of a non-network options report. Six of the RIT-D's including a non-network options report have been completed, with a non-network solution being identified as the preferred option in one case. However, the AER have noted that *"[o]ur assessment of the RIT–Ds undertaken to date has shown that there have been inconsistent levels of non-network engagement and information in reports, particularly in the non-network options report."*[59]

3.4. Summary

As noted at the start of this section, because of the lack of counterfactual and the myriad of factors that drive expenditure decisions it is difficult to conclude anything concrete from the available evidence. One could argue that the out performance on capex indicates potentially greater information asymmetries. Alternatively, the outperformance (or lack thereof) against opex could indicate a lower financial incentive compared to capex. However, both arguments are not robust to scrutiny as this covers a period where demand forecasts were materially inaccurate.

[59] AER (2018), page 26.

4. MODELLING THE STRENGTH OF THE FINANCIAL INCENTIVE MECHANISM

In this section, we model the financial incentives that apply to equivalent opex or capex solutions. Our model uses the underlying assumptions and mechanisms from the AER's post-tax revenue model, roll forward, EBSS and CESS models.

We have modelled the financial incentives under two broad alternative approaches:

- The NSP faces a choice between two equally efficient opex or capex solutions that deliver the same outcomes. In this case, we assume the NSP is responding to a change in output requirements and can implement an opex or capex solution. This solution has a finite duration. At the end of the solution's useful life, the opex allowance is assumed to be adjusted back to the original opex allowance based on original outputs. In other words, we assume that the EBSS does not apply a second time as the 'base opex' is adjusted for the change in outputs.
- The AER's approach, where the EBSS and CESS are used to provide time-independent incentives on opex and capex. If opex efficiencies (or inefficiencies) occur in perpetuity and the WACC is 6% then the incentive strength on opex and capex will be equal. We note that if the opex efficiencies (or inefficiencies) do not occur in perpetuity the EBSS will reverse any original reward/penalties such that the NSPs should only gain/bear the time value of money (i.e., the WACC in the original savings/overspend).

The findings from this exercise are that:

- Under the first approach, our modelling indicates that there is a positive financial incentive for NSPs to prefer capex to opex, assuming that such a trade-off is possible. This incentive diminishes as the assumed life of the asset - and therefore the duration of the opex solution - increases. However, the incentive remains positive for the more common network asset lives of 40 to 50 years. For an asset with an expected useful life of 10-years, an NSP receives over twice the financial benefit for reducing opex compared to reducing capex,[60] and it would face half the financial loss if it chose to overspend on capex rather than opex. If the asset's expected asset life is 50 years then the benefit reduces to around 10% for favouring capex over opex.[61]
- Under the second approach, our modelling indicates that that achieving capex efficiencies may provide a slightly higher financial return than achieving opex efficiencies (i.e., an incentive to prefer opex rather than capex). This is driven by the different tax outcomes resulting from opex or capex. This differential is smaller than under the alternative assumption, however it also gets closer to 1 as the duration of the solution increases.
- The DMIS increases the incentive to undertake opex, but only for certain projects.

In this section, we set out our approach to testing the financial incentives that NSPs face once they receive their allowances. We do this in order to test whether the NER and AER's current approach to applying the rules may create a financial incentive for NSPs to prefer capex over opex.

As set out above, once the NSPs receive their allowances, different incentives will apply. In our modelling we have focused on the financial implications from the CESS and EBSS. We have excluded the DMIS from the modelling, as this needs to be assessed on a project-by-

[60] An NPV ratio (which is the capex solution divided by the opex solution) of 0.5.
[61] An NPV ratio of 0.91.

project basis and cannot therefore be modelled quantitatively to determine a general effect on NSP incentives.[62] We note that the AER can choose not to use an EBSS or CESS for individual NSPs (it did not apply an EBSS in the 2015 decisions for ACT and NSW). However, as these incentive mechanisms were designed to help balance financial incentives across capex and opex, and are expected to be used by the AER for most NSPs going forward, we apply both mechanisms in our modelling.

4.1. Our approach

We have attempted to keep the modelling relatively simple and focus on the NPV difference of the reward/penalty that NSPs receive from out-/under-performing on capex or opex. As our starting point, we have relied on the AER's January 2015 distribution post-tax revenue model (PTRM) version 3, the AER's November 2013 EBSS and CESS Excel models, and the AER's December 2016 rollforward model (RFM).

We have considered the financial modelling on the basis of two broad alternative assumptions:

- The NSP faces a choice between two equally efficient opex or capex solutions that deliver the same outcomes. In this case we assume the NSP is responding to a change in output requirements and can implement an opex or capex solution. This solution has a finite duration. At the end of the solution's useful life the opex allowance is assumed to be adjusted back to the original opex allowance based on original outputs. In other words, we assume that the EBSS does not apply a second time as the 'base opex' is adjusted for the change in outputs.
- The AER's approach, where the EBSS and CESS are used to provide time-independent incentives on opex and capex. If opex efficiencies (or inefficiencies) occur in perpetuity and the WACC is 6% then the incentive strength on opex and capex will be equal. We note that if the opex efficiencies (or inefficiencies) do not occur in perpetuity the EBSS will reverse any original reward/penalties such that the NSPs should only gain/bear the time value of money (i.e., the WACC in the original savings/overspend).

To model these assumptions, we compare present value (PV) equivalent opex or capex 'solutions'. The solutions are assumed to last for the same time period and deliver the same levels of reliability and safety. That is, the opex solution is in place for the length of the alternative capex solution's useful asset life. However, under the second broad assumption outlined above, we assume that opex continues after the end of the solution's life and the EBSS applies again at this point.

[62] We have also excluded the Service Target Performance Incentive Scheme (STPIS). This is an incentive based on maintaining services quality or self-funding (based on consumers' willingness-to-pay) improvements services.

Starting scenario

We start from a scenario where:

- We have two hypothetical NSPs, with the same starting expenditure and WACC allowances, and the same expected actual expenditure. However, when faced with out- or under-performing against their expenditure allowance:
    - one will choose to out/under-perform only on opex (OpexNSP); and
    - the other will choose to out/ under-perform only on capex (CapexNSP).

  If the NSPs' actual expenditure and WACC are the same as allowed, their NPV of cash flows will be zero.
- We assume that the choice of opex or capex solutions available to the NSPs provide the same outcomes for consumers (i.e., consumers receive the same quality of service from either the capex or opex solution).
- Both companies have a real WACC of 6%. This matches the discount rate used by the AER to calculate the 30% CESS sharing factor, using the EBSS in perpetuity savings. For the base case comparison, the allowed WACC and actual WACC are assumed to be the same.
- We set the capex and opex solutions to have equivalent PV expenditure for the NSP. For example, if the NSP can underspend on capex by $10m in year 1, we estimate the PV opex based on the asset life and the NSP's actual cost of capital. This means that an opex solution/ underspend is assumed to last the same length of time as the capex solution/ underspend. We use actual WACC rather than allowed WACC to discount the cash flows.
- There is only a single regulatory period for the NSPs to make a choice, and each subsequent regulatory period reflects the decisions made in the first. Opex in the fourth year sets the opex allowance and actual for each future year (the 'base-step-trend' approach). The cash flows are assumed to last as long as the asset life.
- Under the first broad approach, we assume that the cash flows stop at the end of the solution's life.
- All values are in real terms (this is to simplify the model and does not impact the outcomes).

Our other starting assumptions are set out in ANNEX B.

Metric to measure the relative financial incentive strength from opex or capex out/underperformance

In order to assess the relative NPV gains/losses from out/underperformance on opex or capex we have calculated an 'NPV ratio' which is:

$$NPV\ ratio = \frac{NPV\ capex\ out/underperformance}{NPV\ opex\ out/underperformance}$$

If the NPV ratio is below 1 then:

- For underspends, reducing opex provides a greater financial return than reducing capex. For example, if the ratio is 0.5 it would mean that reducing opex would provide a financial return twice as much as for reducing capex.
- For overspends, increasing capex is preferred to increasing opex. For example, if the ratio is 0.5 it would mean that increasing capex would cost half as much as increasing opex.

If the NPV ratio is above 1 then:

- For underspends, reducing capex provides a greater financial return than reducing opex. For example, if the ratio is 2.0 it would mean that reducing capex would provide a financial return twice as much as reducing opex.
- For overspends, increasing opex is preferred to increasing capex. For example, if the ratio is 2.0 it would mean that increasing would opex cost half as much as increasing capex.

Theoretically, if the incentives between opex and capex are equalised the NPV ratio should be 1 if the actual WACC is equal to the allowed WACC. A ratio below 1 supports a financial capex bias, while a ratio above 1 supports a financial opex bias.

Model input choices

We have set the model up to allow a range of inputs to be varied. The key variables we have identified as of particular interest are:

- Asset life. This relates to the capex in the first year and any over/underspend from this.
- Allowed and actual WACC parameters: gearing, post-tax real return on equity, and pre-tax return on debt.
- The level of capex out/ underperformance.

4.2. Modelling results

Before looking at the results it is important to note the following:

- Different levels of capex out/underperformance do not change the results of the NPV ratio e.g., a $10m outperformance produces the same NPV ratio as a $1m outperformance.

- The NPV ratio is also symmetrical for out/ underperformance. This is to say that an underspend of $X on capex or opex will generate the same NPV ratio as an overspend of $X on capex or opex.

These factors mean that we do not need to undertake sensitivities around the level of out/underperformance and the type. However, the reader should bear in mind that large under/outperformance may not change the NPV ratio but it will change the overall level of cash flows and therefore the magnitude of these changes may influence the NSP's decisions.

DMIS

Because of the project specific nature of the DMIS we have not been able to model this generically (i.e., to assess the impact across all scenarios and sensitivities). In addition, as the DMIS has not yet been used in practice we have no 'real world' examples to compare against. However, the design of the mechanism is to provide a financial incentive to undertake opex rather capex (or at least defer capex). Our analysis indicates that when applied to projects the DMIS would have the effect of increasing the NPV ratios. That is, we would see a shift upwards of the NPV ratio curve shown in Figure 4.1.

While the DMIS will increase the NPV ratios, we cannot say whether this will increase the ratio to, or above, 1 at every level of the asset life.

4.2.1. Modelling the decision between equally efficient opex and capex solutions

As noted above, our primary modelling starts from a different assumption than the AER's previous analysis. We assume that the solutions, whether an overspend or underspend, are in response to certain requirements. For example, if there is an unexpected increase in demand that needs to be responded to. We assume that the need can have a limited time requirement and that this is known when the solution is put in place, for example, a specific increase in demand for 10 years or 80 years. At the end of the solution requirement we assume that the allowances are adjusted to reflect the forecast changes, i.e., the opex allowance would be reflect a step down in demand.

We believe that this assumption reflects the more micro level decisions that an NSP might make.

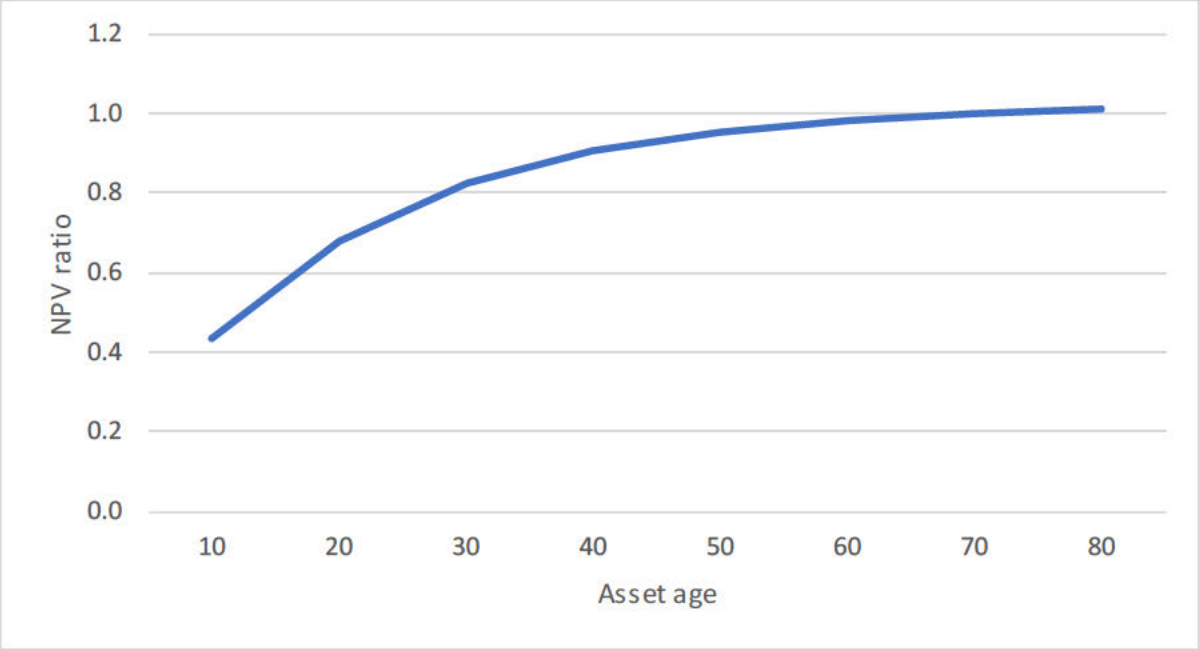
Differences in incentive strength change depending on the expected asset life of the capex solution/ underspend.

From the outset we found that the NPV ratio is highly sensitive to the asset life chosen, and by extension the length of the opex out/underperformance to match the capex out/underperformance.

The changes in the NPV ratio as the asset life changes is illustrated in Figure 4.1 below. We can see that for very short asset lives (10 years) there is a clear financial benefit from opting to reduce opex rather than capex in the case of outperformance or undertake capex rather

than opex in the case of an overspend. As the asset life increases the NPV ratio gets closer to 1,[63] implying that for long-life asset/ opex solutions the NSPs should be relatively in different (for financial reasons) as to the choice of approach. Although, this does not take account of the uncertainty that NSP may face from adopting annual opex rather than an upfront capex solution.

Figure 4.1: NPV ratio based on asset life[64]



Source: CEPA

The unbalanced opex/capex incentives are largely due to how the EBSS and CESS reward the NSPs. The EBSS provides an NSP with a larger upfront savings retention compared to the CESS if the sharing of savings does not last in perpetuity. To illustrate this in simple terms, $10m in savings divided by 10 years creates a large annual saving than $10m divided by 30 years. The CESS upfront reward does not change with the asset age.

Typical network asset lives for the DNSPs are around 40 to 50 years, which, while close to 1 than shorter asset lives, still indicates a financial benefit to the NSP from undertaking capex (for an overspend)/ reducing opex (for an underspend).

Below we provide a series of examples to explore '*what the NPV ratio mean in practice?*' It is important to bear in mind that these are simplified examples that do not allow for *ex post* or other adjustments to future allowances the AER may make to ensure that incentives work as intended.

[63] The NPV ratio exceeds 1 from around the 70-year asset life point.
[64] The NPV ratio is the Capex under/overspend NPV divided by the opex under/overspend NPV.

Example 1: Underperformance (overspend)

Starting from a base case of both NSPs having a capex allowance of $100m, an expected asset useful life of 40 years, and a WACC of 6%. If we assume that the NSPs' actual expenditure and WACC are in line with allowances then their NPV will be zero.

In the first year of the regulatory period, there is a change in requirements that means the NSPs must overspend against their allowance.

The CapexNSP identifies a capex solution that will cost $10m in the first year of the regulatory period (i.e., spending $110m on capex in total). After the incentive mechanisms are taken account of (i.e., the NSP bearing 30% of the overspend), the CapexNSP's NPV loss from overspending on capex is $2.1m.

The Opex NSP identifies an alternative solution that provides the same outcomes but by using opex. The cost of this opex solution is exactly the same as the CapexNSP's solution in PV terms, in this case it leads to an increase in its opex of $0.7m per annum over the next 40 years. After the incentive mechanisms are taken account of (i.e., the NSP bearing $0.7m overspend for six years), the OpexNSP's NPV loss from overspending on opex is $2.3m.

Dividing the CapexNSP's change in NPV by the OpexNSP's change in NPV results in an NPV ratio of 0.91. This means that the OpexNSP is effectively 10% worse-off than the CapexNSP. Therefore, the opex solution would have to be significantly more efficient than the capex solution for a 'neutral' NSP to adopt it. In other words, an NSP using a opex solution would earn a return on equity below that of an NSP adopting a capex solution.

Example 2: Outperformance (underspend)

Starting from a base case of both NSPs having a capex allowance of $50m, an expected asset useful life of 30 years, and a WACC of 6%. If we assume that the NSPs' actual expenditure and WACC are in line with allowances then their NPV will be zero.

In the first year of the regulatory period, the NSPs identify efficiency gains that can be made.

The CapexNSP identifies capex savings of $5m in the first year of the regulatory period (i.e., spending $45m on capex in total). After the incentive mechanisms are taken account of (i.e., the NSP retaining 30% of the underspend), the CapexNSP's NPV gain from underspending on capex is: $1.0m.

The Opex NSP identifies an alternative solution that provides the same outcomes but reducing opex instead. The opex savings are the same as the CapexNSP's savings in PV terms, in this case it leads to a reduction in opex of $0.4m per annum over the next 30 years. After the incentive mechanisms are taken account of (i.e., the NSP retaining $0.4m of the underspend for six years), the OpexNSP's NPV gain from outperforming its allowance is: $1.3m.

Dividing the CapexNSP's change in NPV by the OpexNSP's change in NPV results in an NPV ratio of 0.83. This means that the OpexNSP is around 20% better-off than the CapexNSP.

Therefore, the capex solution would have to be significantly more efficient than the opex solution for a 'neutral' NSP to adopt it. Therefore, there is a financial bias towards undertaking capex rather than opex.

Example 3: Short-life network solution versus services purchased from third parties

What does the NPV ratio mean when considering the implementation of a 'short-lived' capex/opex solution. For example, the use of a battery or demand management to deal with an increase in demand on a feeder.

Let us assume that the capex solution – installing a battery – costs $5m and has a 10 year asset life. The opex solution – purchasing demand response from third parties – has an expected cost of $0.7m per annum for 10 years (PV equivalent to the 10-year battery cost). The reliability and safety to consumers from either solution is the same.

The increase in demand was unexpected and therefore no allowance was made for either the CapexNSP or the OpexNSP. The expenditure is not required for a reliability corrective action.

The NPV cost of implementing the capex solution for the CapexNSP is $1.0m, while the NPV cost of implementing the opex solution for the OpexNSP is $2.3m. The NPV ratio is therefore slightly above 0.4. This means that the CapexNSP will bear less than half the costs of the OpexNSP from investing in a battery rather than buying services from third parties.

While we have not explicitly modelled the DMIS, we understand from AER (2017c) that the NSP will receive an incentive payment equal to 50% of the PV of the expected opex solution costs, in this case $2.5m.[65] Therefore, the OpexNSP will receive a total gain of $0.2m from purchasing services from third parties.

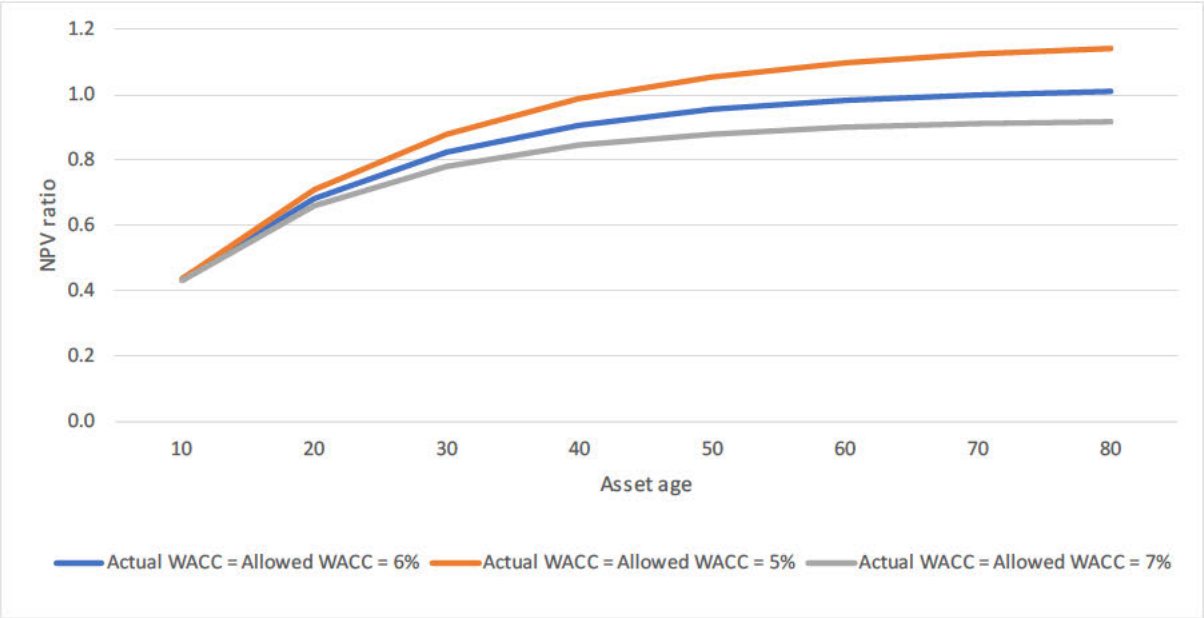
While the DMIS offsets the financial capex bias in this example,[66] it offsets it by requiring additional payments from consumers.[67] We understand from AER (2017c) that if the expenditure was required for a reliability corrective action,[68] the incentive payment would be assessed against the option with the second highest net benefit. In this case as the two options (capex or opex) have the same net benefit the DMIS payment would be zero.

How does the NPV ratio change if the allowed/actual WACC is higher/ lower?

We tested how sensitive the NPV ratio is to different WACCs. We still assume that the actual WACC is equal to the allowed WACC, but we have tested the NPV ratio using a 5% WACC and a 7% WACC. The results are shown in Figure 4.2.

[65] We assume that the NPV of the 'solving' the issue is above the PV cost of the solutions, $5m, and therefore 50% of the total cost is the lower of the two options.
[66] We cannot estimate the NPV ratio as we now have a negative numerator and a positive denominator.
[67] This finding is supported by the AER's example B.1 in Annex B of AER (2017c).
[68] AER (2017c), page 41.

Figure 4.2: NPV ratio based on asset life and differing allowed/actual WACCs



Source: CEPA

It can be seen that a lower WACC increases the NPV ratio, while a higher WACC decreases it. The reasons for this is that changing the WACC has a smaller impact on the CapexNSP's NPV than on the OpexNSP's NPV.

This result fits with our *a priori* expectations that a lower than 6% discount rate would decrease the capex bias. This is because the 30% sharing factor estimated for the EBSS is based on a 6% discount rate being used to estimate the share of opex savings in perpetuity. If the discount rate is lower the sharing factor decreases (approximately 25% with a real discount rate of 5%). Therefore, if considering the benefits to NSPs from longer lived solutions, they retain more of the benefits from the 30% *ex ante* capex sharing factor compared to a 25% in perpetuity opex sharing factor.

This is an important point as the WACC (discount rate) does change over time, and there is no guarantee that it will be 6% real at each price control reset.

What happens to the incentive strength if the NSP's actual WACC is different from allowed?

We estimate two sensitivities:

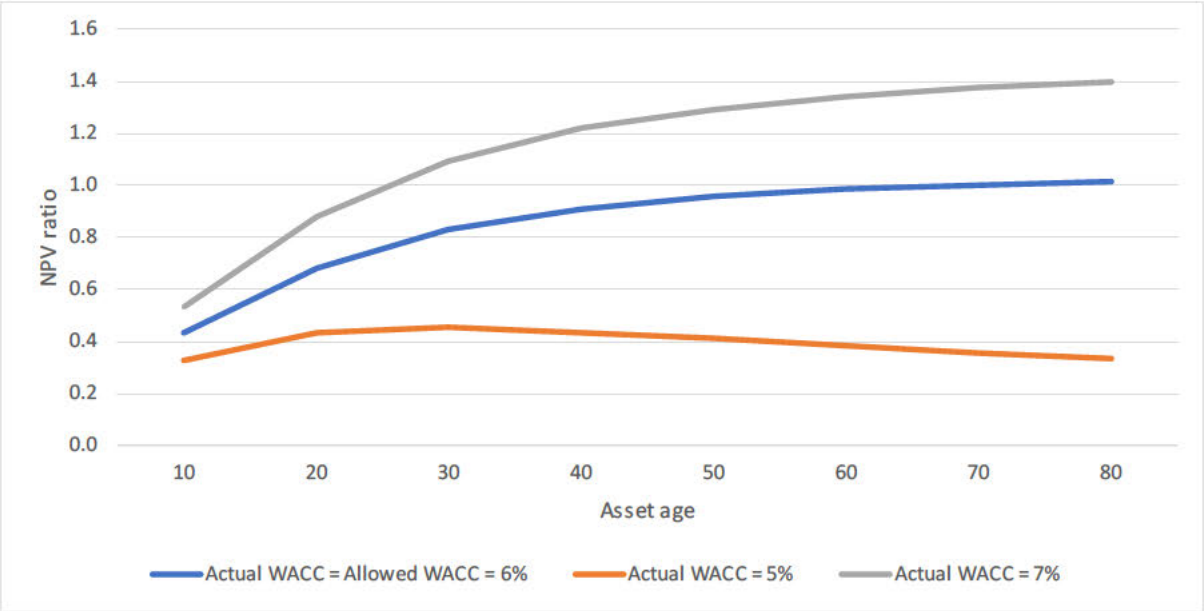
- Actual WACC is lower than allowed, 5% rather than 6%.
- Actual WACC is higher than allowed, 7% rather than 6%.

As there are now two effects occurring – WACC out/underperformance and expenditure out/underperformance – we have estimate the NPV benefit/loss from the WACC being lower/higher than allowed and subtracted this from the NPV benefit/loss from an expenditure out/underperformance.

The outcome here is expected – an actual WACC lower than allowed increases the capex bias, while a higher actual WACC decreases it. However, an interesting result occurs when the actual WACC is lower than allowed and the asset life is increased. As illustrated in Figure 4.3, at first, we see an increase in the NPV ratio, but as the asset life increases the NPV ratio begins to decrease. This means that as the asset life increases the capex bias also increases.

This results from the NPV benefit from the actual WACC being lower than allowed WACC increasing at a faster rate than the benefits/ losses from out/underperformance as the asset life is increased.

Figure 4.3: NPV ratio based on asset life and actual differing from allowed WACC



Source: CEPA

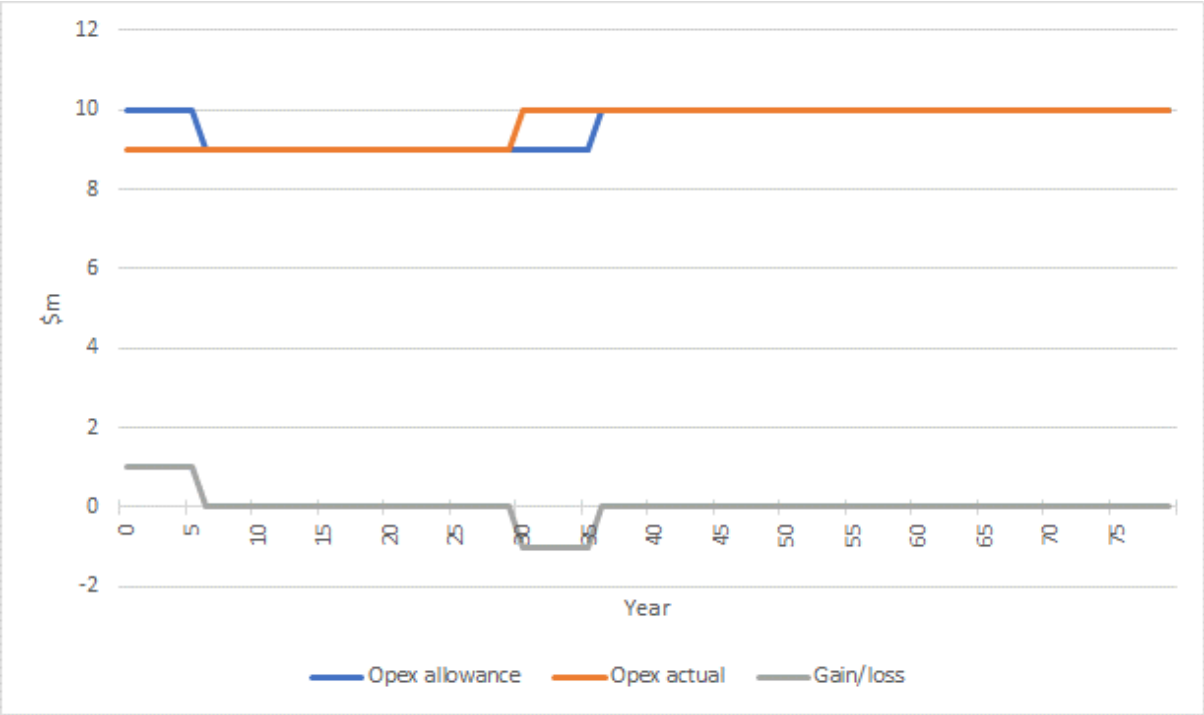
As with the base scenario, the NPV ratio does not change based on the size of expenditure out/underperformance once the WACC out/underperformance is adjusted for.

4.2.2. Financial incentives under the assumption of indefinite opex

An alternative assumption to that which we have used for our modelling above – that the cash flows end when the solution ends – is to assume that the opex cash flows will continue. In this case, the reward/penalty from the EBSS will reverse after the 'solution' ends, and the NSP will only retain/bear the time-value of the under/overspend. We illustrate this in Figure 4.4. In this example, we have an opex underspend in the first year of the first price control and the opex underspend (of $1m per annum) is assumed to last for 30 years. The NSP gains the underspend benefit for 6 years, but after 30 years it bears the six years of overspending its allowance as the life of the underspend comes to an end.[69]

[69] We note that this assumption could also be changed to reflect that the

Figure 4.4: The EBSS with an indefinite opex allowance



Source: CEPA

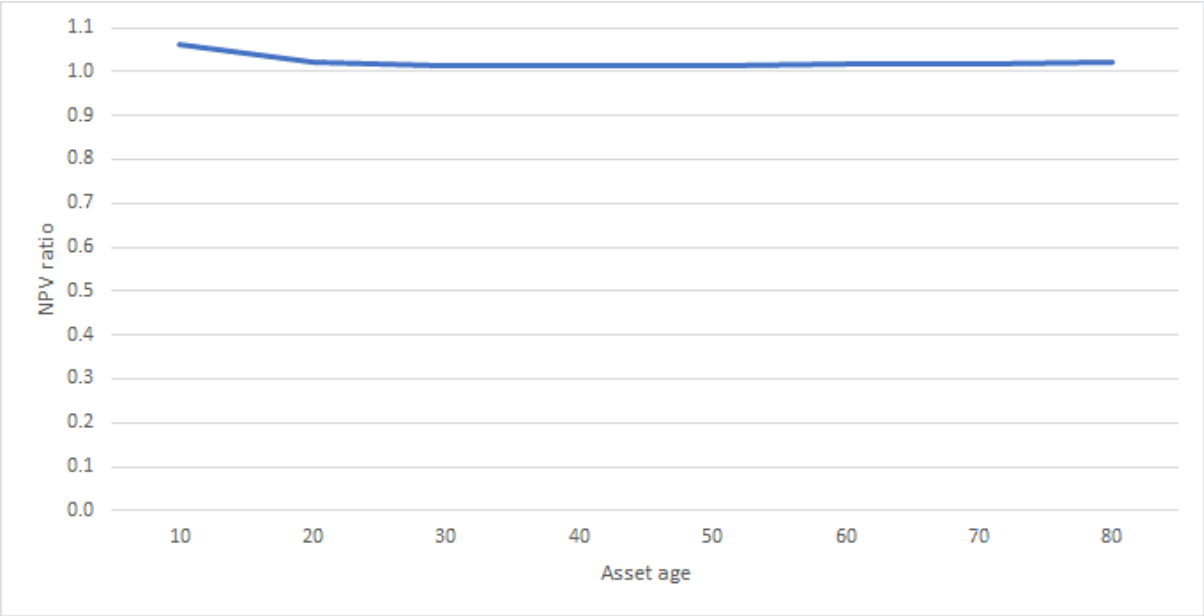
The NSP gains the financing benefits from the early underspend until the 'solution' ends. If the WACC is assumed to be 6% real then the benefits are around 30% of the underspend (as per the AER's in perpetuity calculation). As the capex asset life is assumed to have ended at 30 years and not replaced, the CESS impact does not change.

This assumption is in line with the AER's position of in perpetuity opex savings matching the capex *ex ante* sharing factor. This assumption reflects the AER's top-down approach to setting the opex allowance.

The NPV ratio is closer to one, but there may be a slightly higher financial incentive to make opex efficiency savings compared to capex.

The alternative assumption gives quite a different NPV ratio profile. This is illustrated in Figure 4.5. Here we find that the NPV ratio is much closer to 1, i.e., that the incentive strength on opex and capex is the same. However, for shorter duration 'solutions' there is a higher financial return from reducing capex, when there is the opportunity to underspend, and increasing opex, when faced with an overspend. This is due to the different tax implications from the approaches.

Figure 4.5: NPV alternative assumption



Source: CEPA

Under this alternative assumption, what happens to the incentive strength if the NSP's actual WACC is different from allowed?

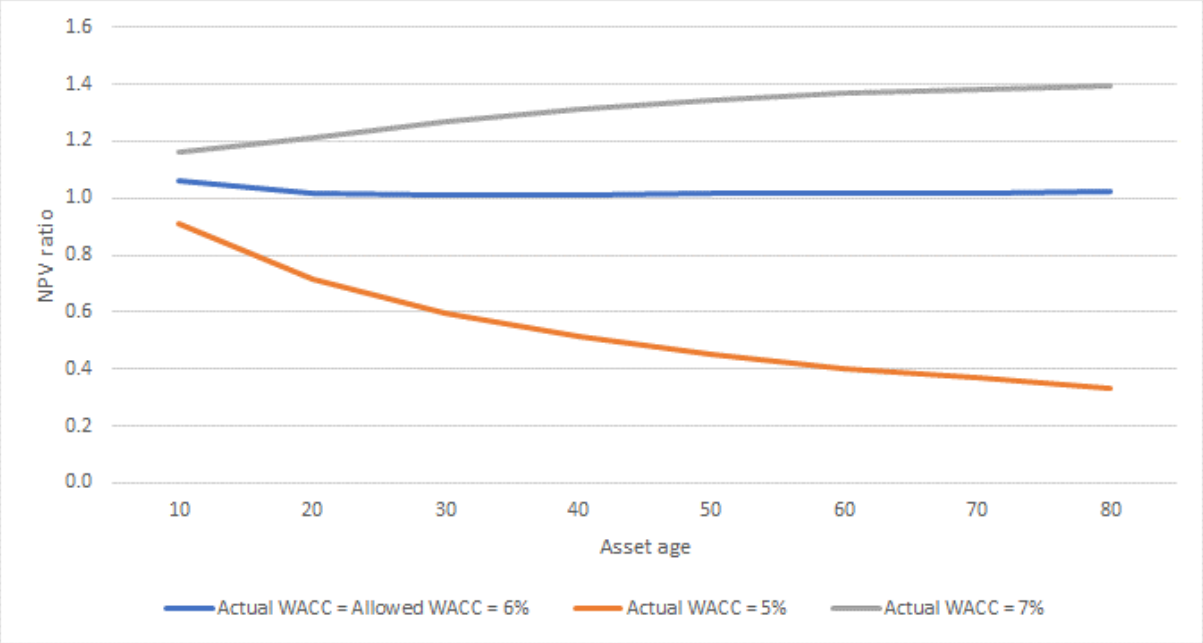
We estimate two sensitivities:

- Actual WACC is lower than allowed, 5% rather than 6%.
- Actual WACC is higher than allowed, 7% rather than 6%.

As there are now two effects occurring – WACC out/underperformance and expenditure out/underperformance – we have estimated the NPV benefit/loss from the WACC being lower/higher than allowed and subtracted this from the NPV benefit/loss from an expenditure out/underperformance.

The outcome here is expected – an actual WACC lower than allowed creates a financial capex bias, while a higher actual WACC creates a financial opex bias. This is illustrated in Figure 4.6, where we can see the NPV ratio for an actual WACC of 5% significantly below that of the base case of a 6% allowed and actual WACC, while the 7% actual WACC scenario provides NPV ratios well above the base case.

Figure 4.6: NPV ratio based alternative assumption, asset life and actual differing from allowed WACC



Source: CEPA

4.3. Deferrals

The examples outlined above describe circumstances in which NSPs may be deciding between equivalent capex or opex solutions. However, it may be equally (or potentially more) likely that NSPs will be able to deploy opex solutions to defer, rather than replace, capital investments. The question is then whether the current framework incentivises efficient capex deferrals. Again, this depends on the interaction between the EBSS, CESS and DMIS (if applicable).

Under the EBSS, if an NSP incurs a *temporary* opex overspend in order to defer capex, this will be neutralised through later adjustments to allowances. That is, the NSP will bear the overspend in the year that it is incurred, but then receive the temporary overspend as an uplift six years later. Therefore, the NSP only bears the time value of money on the overspend.

Under the CESS, the AER may adjust incentive payments in the case of a material capex deferral. At present, materiality is defined qualitatively, allowing the AER to make an adjustment in cases where:

- the amount of deferred capex in the current regulatory period is material;
- the amount of estimated underspend in capex in the current regulatory period is material; and
- the total approved forecast capex in the next regulatory period is materially higher than it is likely to have been without the current period deferral.

When there is a material capex deferral, the AER is able to adjust the CESS payments such that the NSP only retains the 30% of the benefits of the deferral. This is calculated as 30% of the difference between the NPV of the underspend in period n and the NPV of the marginal increase in capex in period n+1.[70]

From the customers' perspective, the capex deferral will be efficient if:

NPV (period n+1 reimbursement for temporary opex overspend in period n) < (NPV capex deferred in period n – NPV capex increase in period n+1)

From the NSP's perspective, they are allowed to retain 30% of the savings from a capex deferral, and only bear the time value of money impact on the temporary opex increase. Therefore, the NSP should have an incentive to implement deferrals so long as:

*30% *(NPV capex deferred in period n – NPV capex increase in period n+1) – NPV (opex overspend in period n) + NPV (period n+1 reimbursement for opex overspend in period n) > 0*

The time value of money impact notwithstanding, this suggests that NSPs should generally have an incentive to undertake a temporary opex overspend in order to defer capex, where the NPV impact of the capex deferral is positive. This is however also subject to:

- implications for reliability standards, and associated penalties and/or reputational impacts if these are not met;
- incentives under the STPIS mechanism; and
- the other incentives referred to in Section 5.

For immaterial capex deferrals, the incentives change. In these cases, the NSP would simply retain 30% of any underspend, strengthening the incentive to undertake a deferral (although it may not necessarily be efficient). Therefore, the incentive strength for deferrals depends partly on how materiality is defined for this purpose; this is likely to become clearer with further experience in the application of the CESS.

The balance of incentives for deferrals could also be impacted by the DMIS, as a DM solution could be used to defer a capex project and therefore be eligible for an incentive payment under that scheme. Again, this would appear to increase the incentive to undertake deferrals (both material and immaterial).[71]

4.4. Summary

Our analysis indicates that the financial incentives on NSPs can vary based on their individual circumstances and assumptions. If we assume that the NSP faces a choice between equally efficient opex or capex solutions then there is a financial incentive for NSPs to prefer capex to opex as long as asset lives are less than 70 years, which they typically are.

[70] AER (2013a), page 42.
[71] Subject to the AER's application of the DMIS in practice.

This unequal incentive exists even if the actual WACC is equal to the allowed WACC. Even if the actual WACC is higher than the allowed rate of return, there is still an incentive in favour of capex where the asset has a relatively short expected useful life.

Alternatively, if we start from the assumption that the EBSS and CESS provide a time-independent financial incentive to achieve efficiencies at any year during a price control, then there is a slightly higher financial incentive to achieve opex rather than capex savings, although this results from differences in tax implications.

Either of the approaches for assessing financial strength may be appropriate depending on the NSP's circumstances. It does highlight that, at least on a post-tax basis (which is how the NSPs should assess the benefits/costs), the incentives are not equal. We note that the AER's implementation of the CESS to match the EBSS was intended to "achieve better balance"[72] between the opex and capex incentives, rather than necessarily equalise them. The introduction of the CESS does help reduce the imbalance between the expenditure approaches.

The DMIS is intended to shift NSPs towards adopting demand management opex solutions by providing NSPs with a financial reward for adopting an opex project over a capex project. The DMIS appears to be more focused around capex project deferrals rather than longer-term solutions.

It is important to note that we are assuming that the capex and opex can be traded-off. At this stage in practice this may be a relatively small proportion of total expenditure, however as we noted in Section 1 with the changing nature of the electricity sector the scope for trade-off may increase in future.

Our assessment of the current incentive arrangements in Section 3 highlights the interactions between the incentives are complex and vary depending on the projects and/or issues the NSPs are reviewing.

Given the differences in how opex and capex are remunerated achieving a balance of incentives between these expenditure types while still using separate mechanisms would be complex. For example, the EBSS sharing factor is determined based on a fixed 6% discount rate, the CESS sharing factor is based on the NSP's allowed WACC, and the assessment of the RITs (and therefore DMIS) uses the regulated cost of capital as the lower bound but there is flexibility for it to be different depending on the level of risk for the project.[73] Therefore, the relative sharing factors and incentive strengths will change over time as the allowed (and actual) WACC change.[74]

[72] AER (2013a), page 12.
[73] AER (2017a), page 20.
[74] Other jurisdictions and regulators, particularly Ofwat, used a combination of mechanisms like the EBSS and CESS to better balance financial incentives over time and between opex and capex. However, Ofwat, like Ofgem, moved to a totex incentive mechanism as it was concerned that the combination of financial incentives

It may be possible to equalise the incentives between opex and capex with separate mechanisms, for example, replacing the EBSS with an *ex ante-based* sharing mechanism (although we do not think this is achievable with the current forms of the EBSS and CESS). However, this does not address other factors, discussed in the following section, that may create a capex bias.

did not provide the balance sort. (The New York PSC also considered the use of totex, however it was ruled (at least for now) due to complications with the accounting standards used in the US.) The totex incentive mechanism allowed for the same ex ante sharing factor to apply to both 'opex' and 'capex' as the regulator capitalises a certain proportion of all expenditure and the appropriate amount of total under/overspend.

5. OTHER INCENTIVES

In addition to the regulatory incentive schemes outlined above, there are a number of other factors that may influence NSP decision making.. The key issues that we identify in this section are:

- A perception that companies prefer to 'grow the RAB', to increase overall earnings and maintain long-term, stable shareholder returns.
- Risk aversion, resulting in a preference for deploying more commonly used capex approaches instead of adopting alternative solutions. This could be due to concerns about the ability to maintain service standards (avoid penalties) or uncertainty around the ongoing expected cost of alternative solutions.
- Reputational incentives. This could include avoiding solutions which may not be 'tried and tested', or concerns about public and investor perceptions if the company appears more inefficient than its peers due to its approach.
- Existing cultural biases that favour a 'poles and wires' solution over alternative solutions, resulting from an NSP's history, skill base and ownership/organisational structure.

On the surface, these factors lean toward promoting a capex bias. However, while it is plausible that these factors could influence capex/opex trade-offs, this is based on relatively subjective judgements.

The preceding sections have assessed the strength of the financial incentives built in to the regulatory framework, both pre-allowance determination (expenditure assessment) and post-allowance determination (incentive schemes). In this section, we consider more qualitative evidence on other incentives that could also influence NSP decisions on opex and capex trade-offs. Drawing on previous investigations into the existence of a capex bias, Table 5.1 below presents a summary of potentially relevant factors.

Table 5.1: Other potential contributors to a capex bias

Factor	Description
Focus on RAB growth	It has been suggested that NSPs (or their shareholders) may operate within a corporate culture that is focussed on growing the RAB, which drives growth in earnings and provides investors with long-term, stable revenue streams. In Section 5.1 we draw on a review of selected analyst reports covering listed NSPs (both in Australia and elsewhere), to consider whether these support this proposition.
Risk aversion	While diversification may balance exposure to business-specific (non-systematic) risks across a portfolio, management of these risks is nonetheless an important consideration for investors. As a result, investors may encourage management to avoid solutions that are higher risk (or at least perceived as such). To the extent that opex solutions are perceived as higher risk than capex solutions, this could influence NSP decisions on whether to undertake opex or capex solutions. We explore this further in Section 0.
Reputational incentives	Reputational incentives could come into capex/opex trade-offs in several ways: • As noted above, if there is uncertainty over the operational performance of opex solutions.

	• A desire to perform well against peers in benchmarking assessments, contributing to a focus on achieving opex efficiencies. Beyond the financial incentives, there may be significant reputational effects from being perceived as an efficient or inefficient network.
NSP culture and skills	Other ways in which corporate culture may influence NSPs' decisions include state or private ownership, the preferences and professional backgrounds (e.g. engineering) of asset managers, organisational structures that separate opex and capex decision-making, and NSP familiarity with or understanding of non-capex options.

Source: CEPA, Ofwat (2011), Frontier Economics (2017).

In the following sections, we focus on the first two sets of factors – RAB (earnings) growth and perceptions of the impact of opex on business risk. It is important to note that this analysis considers evidence for the *presence* of these perceptions, rather than whether they are correct or not. We note Ofwat's 2011 conclusion that the wide-spread perception of a capex bias in the UK water sector was a self-fulling belief.

The latter two factors – reputational incentives and NSP culture and skills - are highly qualitative in nature. Therefore, we are unable to provide a robust view on: the weight that NSPs might place on reputational factors; or how their internal culture, management process and skill base will affect expenditure decisions.

The key reputational considerations for an NSP are likely to centre on:

- Providing the distribution standard network services and prescribed transmission services in a reliable and safe way.[75]
- Being identified as providing efficient delivery of these services.

Anecdotal evidence, such as statements in regulatory submissions and annual reports, indicates that management, at least, may place quite a high weight on these issues.

Ownership structure can affect the decision-making process. State-owned management may have objectives that differ to management of privately-owned utilities; for example, a lesser focus on achieving profits under the incentive framework, with other considerations taking a greater role. A number of Australian commentators, including the AEMC, have noted that government-owned corporations may not have achieved the same level of efficiency as privately-owned companies, although both face the same incentive regime under a CPI-X regulatory design.[76] In addition, and related to the reputational factor, state-owned enterprises may seek to avoid being seen as materially outperforming allowances, as this could indicate that they had over-forecast and therefore charged their customers too much.

[75] There is a financial incentive (STPIS) associated with this as well.
[76] See for example, AEMC (2012b), AER (2015a) and Wood et al (2018).

5.1. Focus on RAB growth

It has been proposed that investor preferences for RAB growth (or at least maintenance), as well as a focus on the RAB as a key metric, could also be a factor in NSP decisions on whether to undertake opex or capex.[77] As discussed in Section 1.4, regulators and other commentators have suggested that NSPs may be focussed on growing their RAB because it allows them to 'earn a return', while opex solutions do not, and this return is stable over the long-term.

While a higher RAB would increase an NSP's absolute profit (other factors held equal), the scope to earn a return above the investors' opportunity cost of capital does not depend on growing the RAB *per se*. Rather, this depends on whether an NSP's actual WACC is below their regulatory allowance. RAB growth must be financed, and new equity investment is required in order to maintain an equity to RAB ratio. Overall, this suggests that a preference for growing the RAB (rather than adopting opex solutions with similar or lower expected PV costs) should hold only when the NSP is able to outperform the allowed WACC.

As noted in Section 1.4, while at odds with economic theory, a preference for RAB growth *could* still exist in the absence of scope for WACC outperformance, due to a number of other factors, including investors seeking long-term stable cash flows, risk aversion (see Section 0) or other behavioural/cultural factors that emphasise the RAB. To assess the plausibility of the latter point being a contributing factor, we have reviewed a selection of analyst reports, to investigate whether their coverage of listed electricity networks generally supports this proposition.

A sample of analyst commentary is presented in Table 5.2 below. While these reports indicate the value that a selection of analysts place on RAB growth, they clearly do not form a comprehensive picture of the market's view of the assets. Nevertheless, they are consistent with our understanding of investor views, both in listed and unlisted markets.

Table 5.2: Focus on the RAB - extracts from investment analyst coverage of energy networks

Analyst/Company	Commentary
Australian energy networks	
Credit Suisse, on Spark Infrastructure	"The [2015 – 2020 regulatory] proposal put forward by SAPN calls for a 50% increase in capex allowance versus the previous regulatory period ... Capex is important as it determines the ability to grow earnings and dividends over time."[78]
Morgans, on Spark Infrastructure	"A key feature of the [AER's draft decision] was a substantially lower capex allowance across the five years (~$1.1bn) than proposed by Transgrid (~$1.8bn). Holding all else constant, this results in higher free cashflow during the regulatory cycle, but reduces long-term growth in the Regulated

[77] See for example, Ofwat (2011), AEC (2017).
[78] Credit Suisse (2014), page 3.

Analyst/Company	Commentary
	Asset Base (and thus long-term revenues and value). However, this capex allowance does not include potentially substantial capex from contingent projects which if triggered will enhance RAB and earnings growth."[79] "We estimate across SKI's three asset companies the return on and return of capital contributes about 60% of revenues. This approach means that the Regulated Asset Base anchors long-term revenues and value."[80]
Morgans, on SP AusNet	"Under the regulatory regime, the [RAB] is a key anchor of revenues and value. All capex deemed efficient and prudent by the AER is rolled into the RAB, providing SPN with surety of a return on and of the capex over the life of the asset."[81]
Macquarie on DUET	"… RAB is not growing, thus making it very difficult for DUE to deliver materially more than inflationary RAB growth across the DUE group." "DUE has limited RAB growth and faces the pressure of regulatory resets in 34% of its asset in CY16 which will ultimately influence its ability to maintain or grow its dividend".[82]
International energy networks	
Credit Suisse, on National Grid UK	"[A]sset base growth underpins the business model" and that National Grid "think that RAB growth and low interest rates can help the shares provide ongoing returns of c8-10%".[83] "Capex and RAB growth is the most important part of NG's bottom-up investment case. .... RAB growth is now the key lever NG has left to grow and try to deliver returns and reach the company's c8-10% p.a. total return objective. … The stock trades on a high premium partly because it has growth, and it has growth because it trades on such a high premium and can get the value creation. The possibility for this circularity turning from a virtuous circle into a vicious circle if capex falls is why we are so concerned about this."[84]
Macquarie, on National Grid UK/US	"National Grid is a highly defensive utility that has benefited from the low interest rate environment, has high returns, unprecedented clarity to beyond 2020, a growing RAB business (particularly in the US), and a strong dividend policy."[85]
Berenberg, on National Grid UK	"More capex is good (it drives RAB growth) as long as it is not too concentrated, putting strains on the balance sheet. For this reason, a sharp reversal of the hiatus in UK generation investment and tightening reserve margin remains a risk."[86]
Macquarie, on	"In our scoring system we have added a 10% discount to transmission RAB in

[79] Morgans (2017), page 1.
[80] Ibid, page 4.
[81] RBS Morgans (2013), page 10.
[82] Macquarie (2015a), page 1.
[83] Credit Suisse (2016a), page 4.
[84] Credit Suisse (2016b), page 6.
[85] Macquarie (2016), page 41.
[86] Berenberg (2017), page 2.

Analyst/Company	Commentary
European energy networks	order to highlight the detrimental use of transmission assets and the subsequent effects on capex, and a 10% premium to power distribution RAB in order to reflect the future opportunity of higher capex in this area and subsequent higher premium to RAB."[87]

While the scope for WACC outperformance is clearly a significant factor in their analysis, the selection of extracts presented above also appears to be consistent with a view that RAB growth is a *generally* desirable outcome in investors' consideration of regulated businesses.

In this context, it is plausible that under the current regulatory framework, a primarily opex-focussed business may not be equally preferred by the current investors in regulated infrastructure assets. If there is a change in operations to favour more opex-based approaches, while overall investment needs might decrease, they may also change. Rather than investors' equity being used for capex (and therefore backed by the RAB), it may instead be needed as working capital to cover the liabilities created from the adoption of opex-based solutions. There are two probable key changes that occur in this scenario:

- **The NSPs' operational leverage decreases.** That is, the NSPs' fixed costs decrease as a proportion of their total costs.
- **Uncertainty over the NSPs' liabilities increases.** As illustrated in Section 3.1.1 and discussed in the following section, NSPs would be more exposed to longer-term cost uncertainty.

The investors that were previously happy to invest in the NSPs when their equity was backed by the RAB may not be so inclined to provide working capital, nor accept the level of risk associated with opex-based solutions, unless reflected appropriately in the regulatory framework. In the extreme - and unlikely - event that NSPs become 'asset light', a margin on all their opex may be required to reflect working capital requirements and risk.[88]

In summary, the anecdotal evidence available indicates that investors are comfortable with the long-term stable returns associated with a RAB-based approach under the current regulatory framework. This perception may discourage NSPs from adopting more opex-based solutions as they may diminish the stability (or growth) of the RAB, without any increase in the return on equity.

5.2. Opex and business risk

As discussed in Section while diversification may balance business-specific (non-systematic) risks across a portfolio, management of these risks is nonetheless an important

[87] Macquarie (2015b), page 16.
[88] It is important to note that simply increasing the allowed WACC will not result in a shift to opex approaches and in fact the existing issues would be exacerbated.

consideration for investors. As a result, investors may encourage management to avoid solutions that are higher risk (or at least perceived as such).

To the extent that opex solutions are perceived as "higher risk" than capex solutions, this could influence NSP decisions on whether to undertaken opex or capex solutions. Potential reasons why opex solutions could be viewed as higher risk include:[89]

- If the opex solution involves an ongoing contractual relationship with a third-party:
    1. Transaction costs associated with finding third-party providers and establishing a contract.
    2. Risks associated with managing this relationship (compared to a solution provided in-house), for example managing disputes, performance or insolvency.
    3. Compared to an in-house opex or capex solution, loss of control of the assets providing the service, with associated concerns as to whether the solution will perform as required, when required.
- Uncertainty around how long-term contracts for services would be treated within the regulatory cost assessment process, if the contract term extended beyond one regulatory period.
- Relative to an upfront capital investment, an ongoing opex solution may involve a greater degree of cost uncertainty, due to fluctuations in input costs over time.
- In relation to opex solutions that are innovative, uncertainty over the expected technical performance of the solution.

We note that in responding to several recent rule changes, NSPs have highlighted risks that could be associated with opex solutions, including solutions procured from third parties. For example, in relation to the draft contestability of energy services rule determination, Endeavour Energy observed that:

"If a network "bias" exists, it may be more attributable to the immaturity and high cost of alternative, non-network technologies or the intrinsic inefficiency of decentralised, distributed solutions".[90]

Commenting on the same draft determination, SAPN, Citipower and Powercor noted that:

"Currently, there are risks from fully procuring (rather than owning or co-owning and having some control) DER such as the risk of service non-performance or other corporate stability issues. DNSPs bear the risk of unreliability through the [STPIS]. While contracts with DER providers could mitigate risks, not all providers may be willing or able to take on this risk. …

[89] Drawn in part from Ofwat's investigation into a capex bias in the UK water sector.
[90] Endeavour Energy (2017), page 2.

Further, the transaction costs of design and monitoring detailed contracts with many small individual providers would be significant".[91]

Other submissions to the contestability determination and the alternative to grid-supplied network services determination highlighted potential risks in relation to:

- transactions costs of establishing a contractual arrangement;[92]
- the necessity for contractual arrangements to compensate the NSP for penalties incurred in the event of failure to achieve reliability targets;[93, 94]
- third-party contractor insolvency;[95] and
- increased risk and complexity.[96]

While it is not implausible that such considerations are relevant factors, it is difficult to establish the extent to which they influence NSP decision making. Further, we note that many of the comments summarised above are objecting to proposed *requirements* for NSPs to contract with third-parties to access particular services, rather than expressing a general view on the disadvantages of opex/third-party solutions compared to capex/in-house options.

5.3. Summary

As with any qualitative assessment, we cannot say categorically that cultural or behavioural factors would result in a capex bias. However, there appears, at least for privately owned businesses, that there is a strong perception that growing the RAB is good for investors, which is not always accompanied by an explicit reference to whether the actual cost of capital is higher than the allowed cost of capital based on the BEE.

We also find it highly plausible that alternative (potentially innovative) solutions to undertaking traditional capex approaches may have higher risk associated with them, even if the expected cost is lower than the capex approaches. If investors and/or management are risk averse, then they may prefer the higher-cost option if the uncertainty around the expected cost is lower.

[91] SAPN / Citipower / Powercor (2016), page 5.
[92] AusNet Services (2017), page 5.
[93] Ibid.
[94] ENA (2017).
[95] Essential Energy (2017).
[96] Ausgrid (2017).

6. CONCLUSIONS

A key design aspect of the NEM regulatory framework, and recent rule changes, is to incentivise genuine outperformance and innovation in order to mimic the operation of a competitive market. The original design of the NEM regulatory framework is unlikely to have anticipated the increasing availability of alternatives to 'traditional' (NSP-initiated, capex-based) approaches to delivering regulated network services, provided in-house by the NSP or out-sourced from third parties, and focused on providing investors only with a return on the RAB to cover their opportunity cost of capital.

The framework is continually evolving with new rule changes and a suite of incentive mechanisms is now in place to meet the requirements set out in the various rule changes. However, using a suite of mechanisms that have been developed at different times over the last 10 to 15 years in response to rule changes, can result in unintended incentives on NSPs, or the NSPs misinterpreting and responding to the incentives incorrectly.

We have analysed the explicit financial incentives built into the regulatory framework and other factors that may influence NSP behaviour. Our analysis indicates that:

- **The financial incentives for NSPs vary depending on individual circumstances, but they are not equal between opex and capex.** If we assume that an NSP is considering whether to undertake equally efficient opex or capex solutions, that deliver the same outcomes, our modelling indicates that the NSP will have a financial incentive to prefer capex over opex. In contrast, if we assume the EBSS and CESS equalise the incentive strength over time to encourage efficiencies, then there is a slight financial incentive for the NSPs to prefer to achieve capex efficiencies over opex efficiencies.
- **There is no simple fix to the EBSS and CESS to equalise the incentives on opex and capex.** The basis of the CESS *ex ante* sharing factor depends on an assumed in perpetuity opex saving and a fixed discount rate of 6%. Neither of these assumptions are likely to hold in practice. *Prima facie* the most straight forward approach for aligning the incentives would be to set an *ex ante* sharing factor for opex. However, in line with our modelling on the 'choice' between an opex or capex solution, this approach does not address the financial incentive if the actual cost of capital is different from the allowed cost of capital as, for example, a capex solution will be preferred if the actual cost of capital is lower.[97]
- **The DMIS provides an incentive, for specific projects, to favour opex demand management over capex.** The DMIS can, depending on the specific requirements of

[97] Ofgem's and Ofwat's solution to this issue was to simplify the incentive mechanism by treating opex and capex together and capitalising a proportion of the total. This approach does lead to changes in other part of the regulatory framework (such as the treatment of depreciation and the need for financeability assessments).

the project, more than fully offset the financial bias in the underlying framework of the EBSS and CESS.

- **The AER assess capex differently from opex.** The AER typically uses top-down opex benchmarking and trends forward a base level of opex, while capex requires a more bespoke assessment as projects can vary over time. Therefore, NSPs may seek to avoid opex solutions in order to avoid appearing inefficient on the opex benchmarking. This creates both a financial incentive, as opex is potentially more likely to be reduced than capex, and a reputational incentive.
- **The combined effects of the incentive mechanisms are complex.** We have found it difficult to model the interaction between all of the financial incentives. Therefore, we predominately focused on the CESS and EBSS. Each NSP has to assess the incentives and determine how they will respond. Greater complexity increases the likelihood that NSPs will respond in unintended ways.
- **Network capex is likely (at least compared to more innovative opex solutions) to provide more stable cash flows to the NSPs.** Aside from the DMIS, there is no explicit working capital allowance (margin on opex) for changes in the operational leverage of individual NSPs and any associated changes in their risk profile from adopting opex solutions with greater levels of uncertainty around future costs. Therefore, risk averse investors/ management may seek to avoid opex projects with greater uncertainty around future costs and outputs.
- **Anecdotal evidence (including company submissions, financial analyst reports, and credit rating agency reports) indicates that investors are interested in stable long-term cash flows.** Therefore, any shift away from maintaining or growing the RAB will reduce the magnitude of future profits, and therefore future dividend growth. This is regardless of the theory that they should be indifferent to a opex or capex solution if the allowed cost of capital is set equal to their actual cost of capital, and that the size of equity and debt will reduce alongside the RAB.

More generally we note that the current regulatory framework was developed with a RAB based approach at its heart. This incentivised capex, as no return (e.g., a margin) was provided on opex to cover working capital. The provisions of the current regulatory framework have in turn attracted a certain type of investor. This may create a self-reinforcing capex bias.

Overall, the analysis we have undertaken highlights the complexity of the interaction between the incentive mechanisms and how the perception of the incentives can change depending on the assumptions made. Under one set of assumptions – when assuming the NSP is comparing equally efficient opex or capex solutions – there is a financial incentive to prefer capex over opex. In contrast, if we assume that the NSP is assessing the incentives from making efficiency savings (or inefficient overspends) there is a slightly higher financial incentive to achieve capex savings compared to opex savings. Non-regulatory incentives

indicate a capex bias. While we are unable to prove the presence of a systematic capex bias, we are similarly unable to conclude that the incentives provided by the current regulatory framework are balanced across capex and opex.

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ANNEX B MODELLING ASSUMPTIONS

In Table B1 we set out the assumptions used in out modelling. These follow those that the AER typically use for the PTRM, RFM, CESS and EBSS.

Table B1: Model assumptions

Assumptions
We assume all expenditure is in real terms (i.e., zero inflation)
Starting WACC of 6%
We assume that future opex allowances in perpetuity are set based on the fourth year of the first price control.
Capex occurs during the middle of the year, and a half year WACC is applied.
Depreciation is straight-line.
The RAB is rolled forward using actual capex and forecast depreciation. Forecast depreciation in future periods is then adjusted for the remaining asset life and RAB.
WACC applies to RAB at the beginning of the year.
Tax is 30%. Depreciation used for tax purposes differs from depreciation is there is an over/underspend.