# Jemena Electricity Networks (Vic) Ltd

## 2016-20 Electricity Distribution Price Review Regulatory Proposal

Attachment 8-2

Operating expenditure forecasting method and base year efficiency

Public

30 April 2015

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# ABBREVIATIONS

| | |
|---|---|
| 2016 regulatory period | 2016-20 Electricity Distribution Price Review period |
| ACIL | ACIL Allen Consulting |
| AER | Australian Energy Regulator |
| BIS | BIS Shrapnel |
| CAM | Cost Allocation Methodology |
| CMEN | Common Multiple Earthed Neutral |
| CROIC | Cost Recovery Order In Council |
| EGWWS | Electricity, Gas, Water and Waste Services |
| EI | Economic Insights |
| ESV | Energy Safe Victoria |
| FTE | Full-Time Equivalent |
| GSL | Guaranteed Service Level |
| Incenta | Incenta Economic Consulting |
| JAM | Jemena Asset Management |
| JEN | Jemena Electricity Network |
| NEM | National Electricity Market |
| NER | National Electricity Rules |
| NSP | Network Service Provider |
| Opex | Operating Expenditure |
| PFP | Partial Factor Productivity |
| RAB | Regulatory Asset Base |
| RIN | Regulatory Information Notice |
| S&P | Standard & Poor’s |
| SCS | Standard Control Services |
| STPIS | Service Target Performance Incentive Scheme |
| TFP | Total Factor Productivity |
| Totex | Total Expenditure |
| UE | United Energy |
| VBRC | Victorian Bushfire Royal Commission |
| VESI | Victorian Electricity Supply Industry |
| WPI | Wage Price Index |

# OVERVIEW

1. Jemena Electricity Networks' (**JEN**) operating expenditure (**opex**) program delivers critical activities to support the operation and maintenance of our assets, and the continued management of our electricity distribution business.

2. JEN's forecast opex program for the 2016-20 electricity distribution price review period (**2016 regulatory period**) will support the delivery of the safe, reliable and secure electricity supply that our customers told us they value. This is achieved through integrated long-term asset management planning. Delivering this requires robust data, information management processes and investment in maintenance programs that manage risk and meet regulatory requirements.

3. The purpose of this document is to describe our opex forecasts for our electricity distribution[1] and metering services. It also outlines that our method is designed so that the opex forecasts meet the operating expenditure criteria[2] in the National Electricity Rules (**NER**)[3] for our electricity distribution services.

**Key messages**

- Our opex forecast for distribution and metering services are $499m ($2015) and $57m ($2015) respectively over the 2016 regulatory period (see section 3). We developed these using an approach consistent with the opex objective and factor(s) from the NER and guidance from the Australian Energy Regulator (**AER**) (see section 4).
- In the process, we used two methods (see section 1.2):
  - **Base, step and trend method.** This method uses a base year that (i) reflects an efficient and recurrent operating expenditure (base), (ii) adjusts this to account for future changes in our circumstances and operating environment (step) and (iii) changes in output and cost inputs over the 2016 regulatory period (trend), and
  - **Specific year-on-year method.** For items where the use of base, step and trend method is not representative of future costs we forecast incremental costs for each year using a 'zero-based' forecast method.
- We propose 2014 as our base year because we consider this to be an efficient 'launch point' to forecast our opex over the 2016 regulatory period. This is supported by our comparable productivity performances, highlighted in the AER's most recent annual benchmarking report (see section 2.1.1.2 ).
- Despite the challenges we faced in the 2011 regulatory period (see section 2.1.1.1 ), we achieved estimated efficiency gains of $23m ($2015) through the AER's efficiency benefit sharing scheme (**EBSS**) (see Attachment 8–1). These benefits will be shared with our consumers over the 2016 regulatory period.
- Our opex forecast includes a productivity improvement of 4.5% by 2020, in line with expert advice on the productivity improvements attainable and consistent with the AER's expenditure forecasting guideline method.
- We considered our customers' preference (see Attachment 4–1) to maintain our current safety and service levels and respond to changes occurring in our energy market.
- We identified new regulatory, safety or compliance obligations and propose $30m ($2015) of step changes (e.g. for enhanced maintenance program, customer engagement or vulnerable customer assistance) (see section 2.4).

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1 For the purpose of this document, distribution services represent standard control services (**SCS**).

2 In that it reasonably reflects (a) the efficient costs of achieving the *operating expenditure objectives* (NER cl. 6.5.6(a)) and (b) the costs that a prudent operator would require to achieve the *operating expenditure objectives* (see section 4).

3 NER 6.5.6(c) (1) and (2)

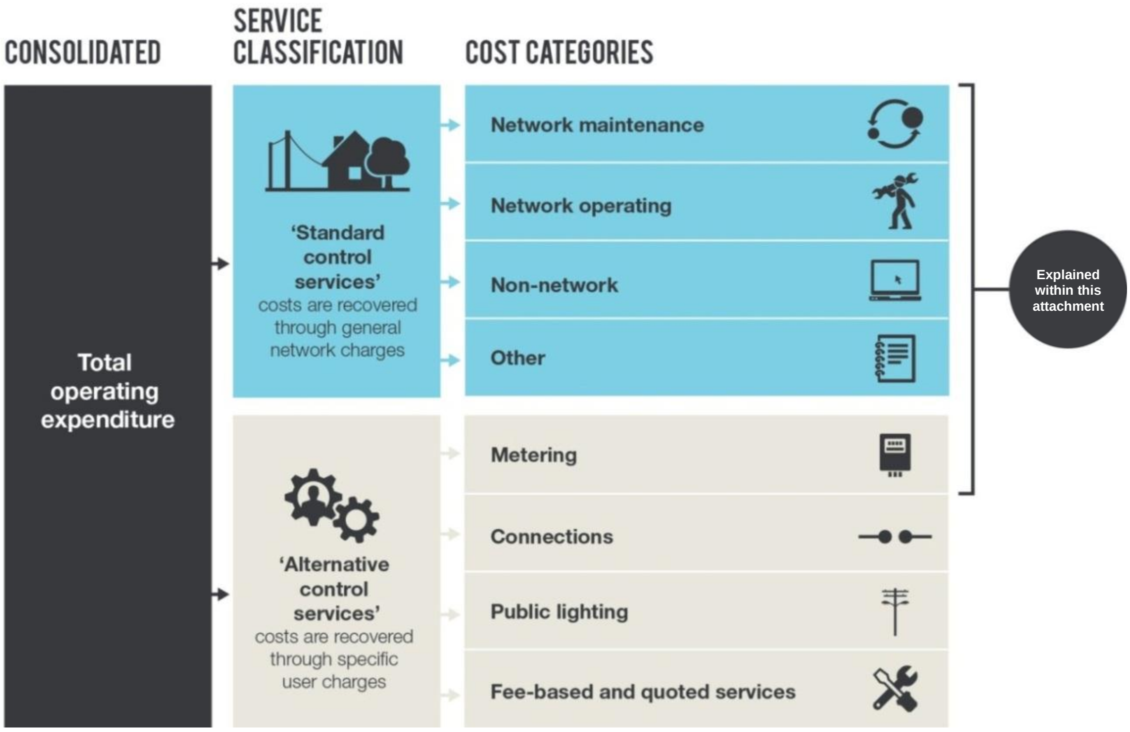
# 1. OUR FORECASTING METHODOLOGY

## 1.1 OPEX CATEGORIES

4. To comply with the NER and to assist the AER in assessing our forecast opex allowance, we have reported our costs in the categories, illustrated in Figure 1–1, and allocated these costs to the relevant services using our approved cost allocation methodology (**CAM**) (see Attachment 7–9). For the purposes of our regulatory proposal the categories include:

1. **Network maintenance**[4] — expenditure associated with conducting routine, non-routine and vegetation maintenance of and around our network, and responding to emergencies (such as outages caused by storms) to ensure we can meet our safety and service obligations and provide the level of service our customers expect, at lowest sustainable cost
2. **Network operating** — expenditure associated with managing the design, planning and operations of the network, and providing training, safety and corporate support
3. **Non-network** — expenditure associated with the operation, maintenance and leasing costs of our IT systems, vehicles and property
4. **Other** — expenditure including levies and land taxes, insurance costs to manage specific risks and the debt-raising costs required to finance our capital program.

**Figure 1–1: Our operating expenditure categories**[5]




4 In response to NER Cl. S6.1.2(1)(4), we do not propose any planned maintenance programs designed to improve the performances for Service Target Performance Incentive Scheme (**STPIS**) benefits and therefore cannot report any cost or methodology.

5 For 'Metering services' expenditure (also explained in this document), we have reported the costs of providing metering and meter data charges for type 5 and 6 smart meters, into the categories (used for distribution services).

## 1.2 FORECASTING METHODS

5. We used two methods to develop our forecast opex for each expenditure category,:

- **Base, step and trend method**[6]—this uses a base year that reflects efficient and recurrent opex, and adjusts this to account for future changes in our circumstances and operating environment and changes in output and other cost inputs over the 2016 regulatory period. To apply this method we:
  - Propose 2014 as our base year, which is the most recent year for which full-year actual costs are available prior to the AER's final decision being made, and subtracted costs relating to non-recurrent events and circumstances that are not expected to endure
  - Trend the adjusted base year costs forward—by escalating or de-escalating the forecast to reflect changes in key cost inputs, productivity improvements and output growth, and
  - Add or subtracted step changes in opex not captured by the base year expenditure or trend escalation, to reflect other expected events or programs over the 2016 regulatory period, such as changes to regulatory obligations, our operating environment or customer preferences identified through our engagement with them, and
- **Specific year-on-year method**—for items where the use of the 'base, step and trend' method is not representative of future costs, we estimated the forecast incremental costs for each year of the 2016 regulatory period, using a 'zero-based' forecast method.

6. **Table 1–1** sets out the forecasting method applied for each opex cost category for distribution services.

**Table 1–1: Methods used for each opex category for distribution services**

| Cost categories | Base, step and trend method | Specific year-on-year method |
|---|---|---|
| **Network maintenance** | | |
| Routine maintenance | • | |
| Non-routine maintenance | • | |
| Emergency response | • | |
| Vegetation management | • | |
| **Network operating** | | |
| Management | • | |
| Network planning | • | |
| Network control and operational switching | • | |
| Project governance and related functions | • | |
| Quality and standard functions | • | |
| Other | • | |
| Corporate overheads (excluding IT) | • | |
| **Non-network** | | |

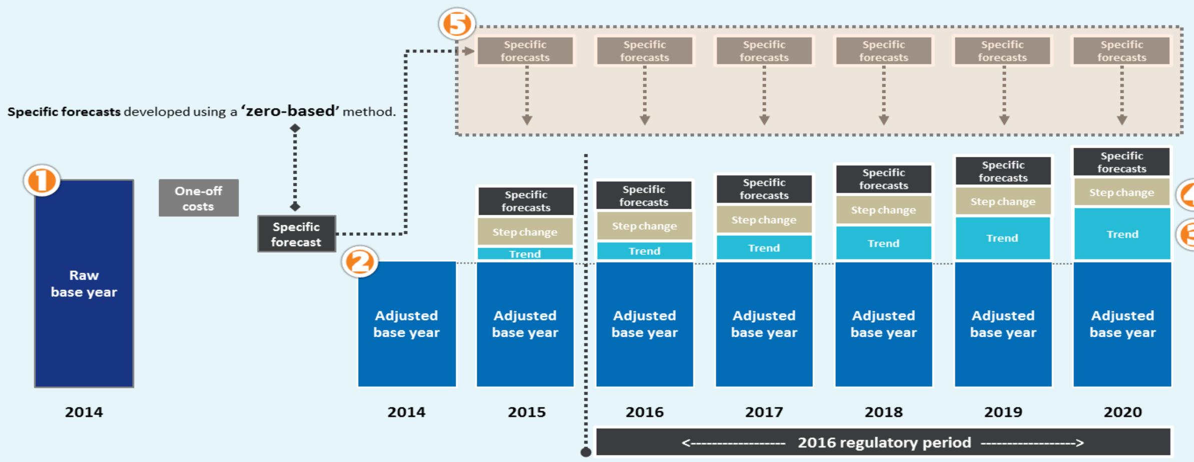
6 For example, see AER, *Better Regulation, Explanatory Statement Expenditure Forecast Assessment Guideline*, November 2013, section 5.3.1 and AER, *Access arrangement final decision, Envestra Ltd 2013–17, Part 1*, March 2013, chapter 7.

| Cost categories | Base, step and trend method | Specific year-on-year method |
|---|---|---|
| Information technology (**IT**) | • | |
| Motor vehicles | • | |
| Buildings and property | • | |
| **Other** | | |
| Levies (incl. license fees) | • | |
| Guaranteed service level (**GSL**) payments | | • |
| Demand side management | | • |
| Self-insurance | | • |
| Debt raising costs | | • |

### 1.2.1 OUR FIVE-STEP APPROACH TO OPEX FORECASTING

7. This section sets out the forecasting approach we have applied to forecast our opex over the 2016 regulatory period, which involves five steps, as illustrated in Box 1–1 and described in the following sections.

**Box 1-1: Our five-step approach to opex forecasting (illustrative purposes only)**




**Our five-step opex forecasting approach**

1. **Step 1:** *Establish the efficient base year.*
2. **Step 2:** *Adjust the base year for non-representative expenditure*
3. **Step 3:** *Trend the base year forward*
4. **Step 4:** *Adjust the trended base year for step changes*
5. **Step 5:** *Add specific forecasts*

8. The specific forecasts are developed using a 'zero-based[7]' forecast methodology (see section 2.5).

[7] Zero-based forecasting is one all estimates are prepared from start and no previous data is available, so all assumptions are made from scratch and all costs relations are made using standard costing methods.

#### 1.2.1.1 Step 1 – establish the efficient base year

9. We reviewed our historical revealed costs and propose 2014 (covering the period 1 January 2014 to 31 December 2014) —which we believe is efficient (see section 2.1.1 for more detail)—as the 'launch point' to forecast our opex for the 2016 regulatory period.

10. Additionally, our private ownership, our customers' expectations and the regulatory framework provide us with strong incentives to continue improving our productivity, including managing and reducing our opex over time. This is reflected in our opex current period performance for distribution services, where we managed to reduce our opex over time to 2014 (see Attachment 8–1 for more detail).

#### 1.2.1.2 Step 2 – adjust the base year for non-representative expenditure

11. We then adjust our base year opex to create a recurrent 'launch point' for forecasting opex in the 2016 regulatory period by:

- Subtracting costs that are not expected to endure—non-recurrent (or one-off) costs (see section 2.2.1), and
- Adjusting categories of cost for which the base year does not provide an efficient base level from which to forecast future expenditure requirements, or for which there exists another specific forecasting method that will provide a better estimate of these forecast costs (see section 2.2.2).

#### 1.2.1.3 Step 3 – trend the base year forward

12. We then trend our adjusted base year opex forward, escalating the forecast for our proposed real rate of change in opex (see section 2.3.1), which is made up of:

- **Price growth** — labour and material costs or the 'input costs to do the work' (see section 2.3.2)
- **Output growth** — customer numbers and system physical capacity of our network or the 'amount of work' that will need to take place (see section 2.3.3), and
- **Productivity growth** — opex partial factor productivity or the 'improvement in productivity to do the work' to account for returns to scale, operating environment factors and technical changes (see section (1)).

#### 1.2.1.4 Step 4 – adjust the trended base year for step changes

13. We then add or subtract forecast costs and savings arising from foreseeable incremental step changes to our opex forecast (see section 2.4).

14. We consider that each proposed step change reflects expenditure required by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering electricity distribution services (see Attachment 8–6).

#### 1.2.1.5 Step 5 – add specific forecasts to the trended base year

15. We finally add the specific forecasts — that we estimate using a 'zero-based' forecasting methodology—to our trended adjusted base year (including step changes) to derive our total opex forecasts for the 2016 regulatory period. These occur due to service reclassifications between the 2011 and 2016 regulatory periods (see section 2.5.6).

# 2. KEY INPUTS AND ASSUMPTIONS

16. The NER require us to set out the key variables and assumptions used in developing our forecast opex, and the methods used to develop these forecasts.[8] This section describes the key inputs and assumptions underlying our opex forecast, including the basis of the specific forecasts, and substantiates these inputs and assumptions.

## 2.1 ESTABLISHING THE EFFICIENT BASE YEAR

### 2.1.1 BASE YEAR EFFICIENCY

17. We propose 2014 as the base year for both our distribution and metering services, for which we have audited revealed costs, and use this as the basis for developing our forecast opex over the 2016 regulatory period.

**Box 1-2: Our proposed base year is efficient—consistent with the NER**

After making the adjustments set out in section 2.2, our adjusted base year opex is consistent with the NER[9] given it is:

- The latest available information at the time of preparing the forecast, consistent with the AER's expenditure forecast assessment guideline[10]
- Representative of our recurrent opex—non-recurrent costs and specific forecasts have been subtracted from the base year opex (see section 2.2.2)
- In line with the AER opex allowances over the 2011 regulatory period (see section 2.1.1.1 ), despite the challenges we faced through unforeseen and uncontrollable increases in our costs following additional regulatory, safety and compliance obligations (see Table 2–2 within Attachment 8–1) and the loss of cost savings previously realised through synergies after JEN (via JAM) handed back shared functions arrangements back to United Energy (**UE**)
- Consistent with the AER's guidance, where it notes "*if a network service provider (***NSP***) operated under, and responded to, an effective incentive framework, actual past expenditure should be a good indicator of the efficient expenditure the NSP requires in the future."* [11]Since the Victorian NSPs' privatisation, it is clear that we responded positively to the EBSS over the past twenty years (see Attachment 8–1)
- Supported by a time series analysis of historical opex and econometric analysis of our opex cost function (see section 2.1.1.2 ), with sufficient evidence to suggest that the base year is materially efficient (see Attachment 8–5), and
- Consistent with the costs incurred by a prudent service provider acting efficiently (see section 2.1.1.3 ).

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8 NER Cl S6.1.2(3)

9 NER, C 6.5.6 (a) requires our forecast operating expenditure to achieve the *operating expenditure objectives*.

10 The AER notes on page 92 of its Forecast Expenditure Assessment Guideline (Nov 2013), that *"typically, we use the revealed costs of the second or third last year in a regulatory control period as the base year. The second last year is the most recent available data at the time of the determination and likely to best reflect the forecast period. Sometimes, we use the third last year, being the most recent year of available data when the NSP submitted its regulatory proposal."*

11 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, Nov 2013, p 42

#### 2.1.1.1 Current period performance

18. Figure 2–1 summarises our distribution services opex performance against the AER allowances over the 2011 regulatory period. At a total level, we expect to incur $379m ($2015), which is $43m (or 13%) above the allowance of $336m ($2015).

19. The AER set our opex allowances back in 2010. Since then, the energy market has significantly evolved, reflected in unforeseen (and mostly uncontrollable) increases in costs, which are primarily due to:

- Additional regulatory, safety and compliance obligations, which were mandated by Energy Safe Victoria (**ESV**) or the Victorian Bushfire Royal Commission (**VBRC**), including the Bushfire Powerline Safety Task Force (see Attachment 8–1 for more detail on these new obligations)
- The handing back of some back office functions (which we shared with UE), resulting in dis-synergies.

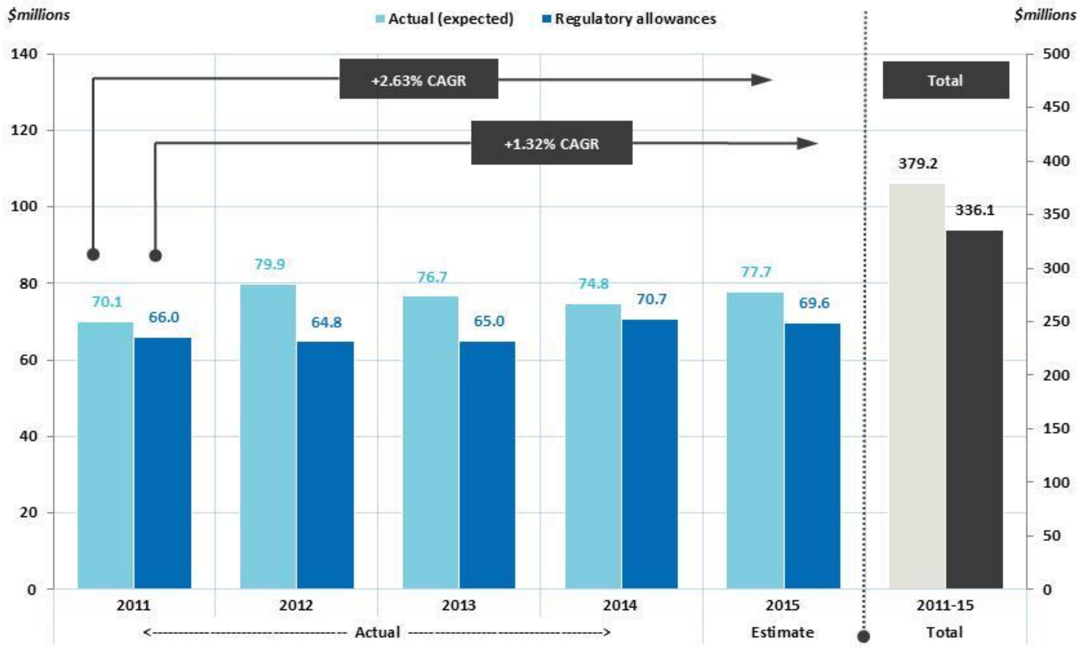
20. Despite these challenges and our stakeholders' pressures (private shareholders, customers and the regulatory framework), we ensured our costs incurred—to meet these additional obligations and transitionary arrangement following the hand back of shared functions—are reflective of a prudent service provider acting efficiently.

21. The AER's EBSS is designed to incentivise network service providers (including JEN) to reduce opex over time to outperform regulatory allowances, and also mute any disincentive to lower costs in the base year. We have been responding positively to the EBSS for the past twenty years following privatisation (see Attachment 5–3).

22. The AER distorted the regulatory framework (by setting our allowances on the premise that synergies would be ongoing, *but* disallowing margins on these shared functions), meaning we had to 'self-fund' our opex over-spend in the 2011 regulatory. This was funded through the benefits that we achieved, through our response to incentives in the 2006 regulatory period. Importantly, our customers did not pay for these additional costs.

23. We were also able to achieve estimated efficiency gains of $23.1m ($2015), which will be shared with our customers over the 2016 regulatory period (see Attachment 8–1 and Attachment 5–3).

**Figure 2–1: Our distribution services opex performance against AER allowances ($2015, $millions)**




(1) Actuals cover the period up to 2014, with 2015 being an estimate.

#### 2.1.1.2 Time series analysis of historical spend and econometric analysis of opex cost function

24. We commissioned an independent report from expert consultant Huegin to analyse the total factor productivity (**TFP**) and opex partial factor productivity (**PFP**)[12] performance of our network to:

- Assess our efficiency—as a cost performer—in both total expenditure (**totex**) and opex against other electricity network service providers (**NSP**s) across the National Electricity Market (**NEM**), and
- Estimate the opex cost function and our forecast opex partial productivity growth rate, in a form that is suitable for incorporation into the rate of change approach for forecasting opex.

**Box 1-3: Our base year is efficient based on our historical productivity performance**

- For the period 2006 to 2013, Huegin[13] states that:
  - No MTFP or opex PFP model is perfect and that these models should not be used in isolation to infer managerial inefficiency due to their limitations
  - While our opex PFP results are generally lower than our MTFP results, consideration of both opex and capex PFP results suggests that our opex PFP performance is not symptomatic of managerial inefficiency
  - These models should not be used deterministically (for example to set expenditure allowances), *but* instead should be used in conjunction with other information (e.g. a NSP's regulatory proposal)
  - With reference to its opex cost function econometric analysis, our forecast average annual opex PFP growth rate over the 2016 regulatory period is 0.89% when returns to scale, the impact of operating environment factors and technical changes are considered, and
  - There is sufficient evidence to suggest our revealed base year is materially efficient.

25. We have carefully reviewed the AER's most recent annual benchmarking report[14] and other relevant measures of benchmark opex that would be incurred by an efficient distribution NSP. We support the use of benchmarking as useful cross-check information, but not in a deterministic way to set expenditure allowances. Attachment 8–4 provides more detail our view on the role of benchmarking in assessing the opex efficiency.

26. We further note that when assessing forecast productivity, the AER

> *"will likely consider…how close the DNSP under consideration is to the efficient frontier in [its] benchmarking analysis".*[15]

27. The AER notes in its most recent benchmarking report that we are in the top quartile of the efficient operators in the NEM and is close to the 'notional' efficient frontier. The following sections summarise the findings from both AER and Huegin on our historical performance for both MTFP and opex PFP.

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12 Both TFP and PFP are comprehensive measures of both (a) actual and (b) forecast year-on-year overall economic performance, which enable targets to be set for productivity growth and its progress to be monitored.

TFP measures total output relative to an index of all inputs used. Output can be increased by using more inputs, making better use of current inputs and by exploiting economies of scale. The TFP index measures the impact of all the factors affecting growth in output rather than changes in input levels.

PFP measures one or more outputs relative to one particular input (e.g. labour productivity is the ratio of output to labour input).

13 Huegin, *Efficiency and growth for the 2016-20 regulatory period, Jemena Electricity Networks (VIC) Ltd Productivity Study*, April 2015.

14 In response to NER cl. 6.5.6(e)(4)

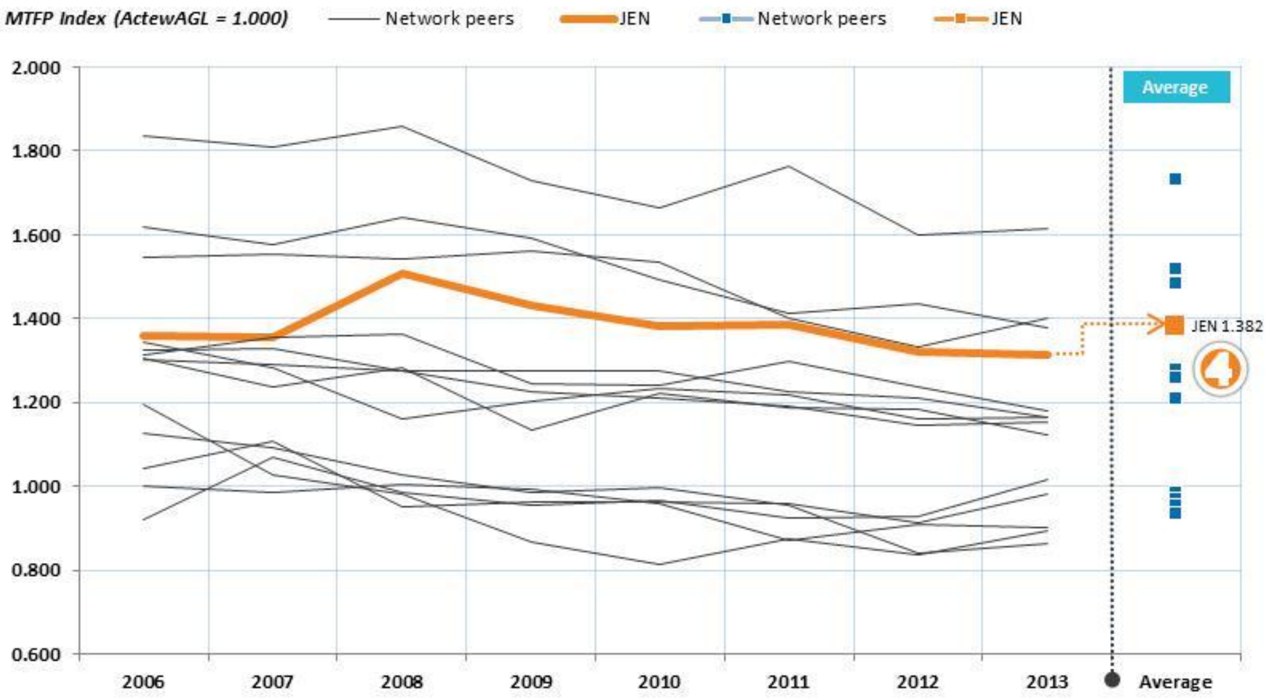
15 AER, *Better Regulation Expenditure Forecast Assessment Guideline*, November 2013, pp.23-24

### Our multilateral total factor productivity (or aggregate performance) – we rank fourth across the NEM

28. On our historical MTFP performance (see Figure 2–2), Huegin concludes that:

- The NEM's TFP faced a decline over time as input variables such opex and capex proxies outweigh the fairly stable output variables (e.g. customer numbers, ratcheted peak demand, circuit length or minutes off supply)
- We are among the top industry performers (ranked fourth across the NEM) based on MTFP measures, in that our historical total expenditure is around or above the threshold for the top quartile efficient frontier for the majority of MTFP models considered by the AER, and
- This provides strong evidence that our expenditure is prudent and efficient, in accordance with NER clause 6.5.6(c), and highlights our ability to balance capex/opex trade-offs for the long-term interests of our consumers, meaning we are operating at lowest sustainable cost.

**Figure 2–2: Our MTFP performance against other electricity NSPs over 2006-13 period (Index)**




Source: AER, *Annual benchmarking report*, Nov 14 (reproduced by JEN)

(1) Ranking is based on average TFP performance over 2006-13.
(2) The firm 'ActewAGL' is selected by the AER as the 'reference firm', i.e. with a base index of 1.000 in the first year (2006).

### Our multilateral opex partial factor productivity (or partial performance) – we rank seventh across the NEM

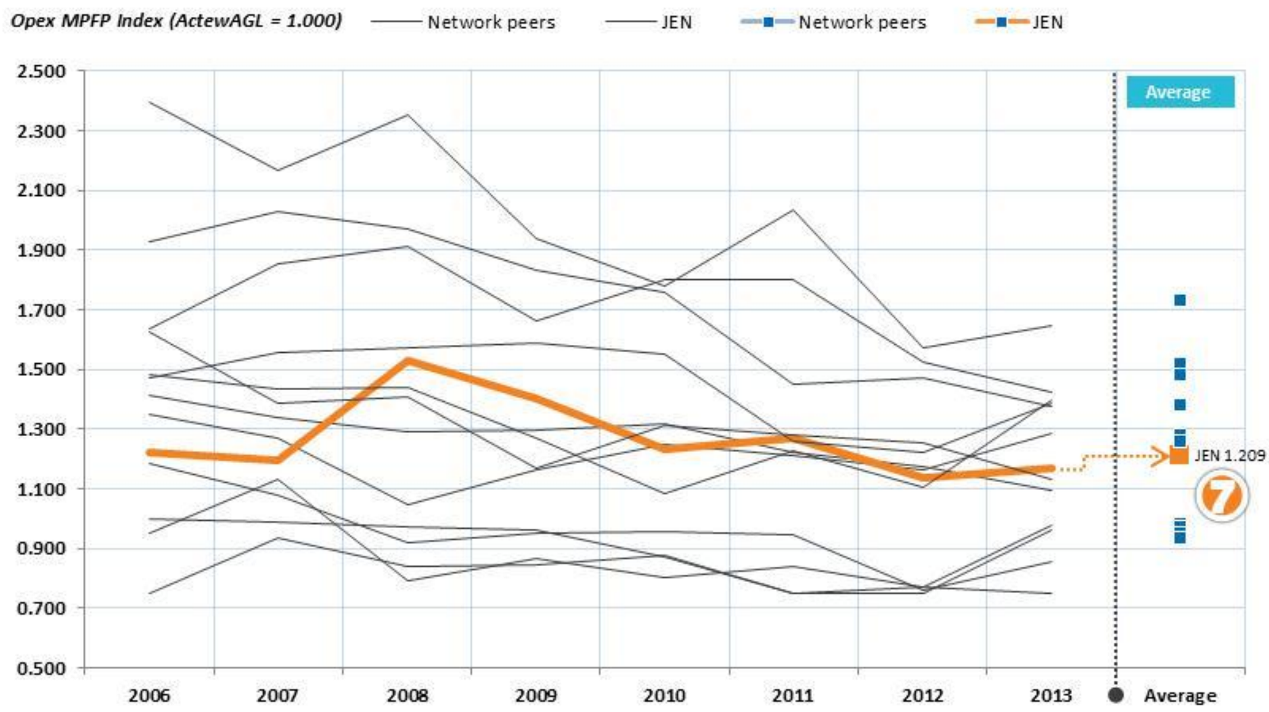
29. On our historical opex MPFP performance (see Figure 2–3), Huegin[16] concludes that:

- While we are ranked seventh in terms of opex multilateral PFP (i.e. relative against other electricity NSPs), the gap between us and the frontier firm has been reduced between 2006 and 2013

16 Huegin, *Efficiency and growth for the 2016-20 regulatory period, Jemena Electricity Networks (VIC) Ltd Productivity Study*, April 2015.

- When considered together, opex and capex PFP measures do not indicate any managerial inefficiency in our historical expenditure. Although our performance on opex PFP measure appears weaker than our performance on capex PFP measures, this is likely to be due to differences in approach to opex/capex trade-offs and capitalisation of expenditure between networks.
- When looking at opex specifically, the results of its analysis of econometric modelling suggest that we are at or above the threshold for top quartile efficiency across the industry.

**Figure 2–3: Our opex MPFP performance against other electricity NSPs over 2006-13 period (Index)**




Source: AER, *Annual benchmarking report*, Nov 14 (reproduced by JEN)

(1) Ranking is based on average TFP performance over 2006-13.

(2) The firm 'ActewAGL' is selected by the AER as the 'reference firm', i.e. with a base index of 1.000 in the first year (2006).

30. Our strong productivity performance provides strong support for the efficiency of our opex forecast. The results demonstrate that we invest in opex programs at lowest sustainable cost and in accordance with good industry practice, promoting the long term interests of our customers.

31. Huegin's full report is provided in Attachment 8–5.

### Huegin's key concerns with the AER's econometric model

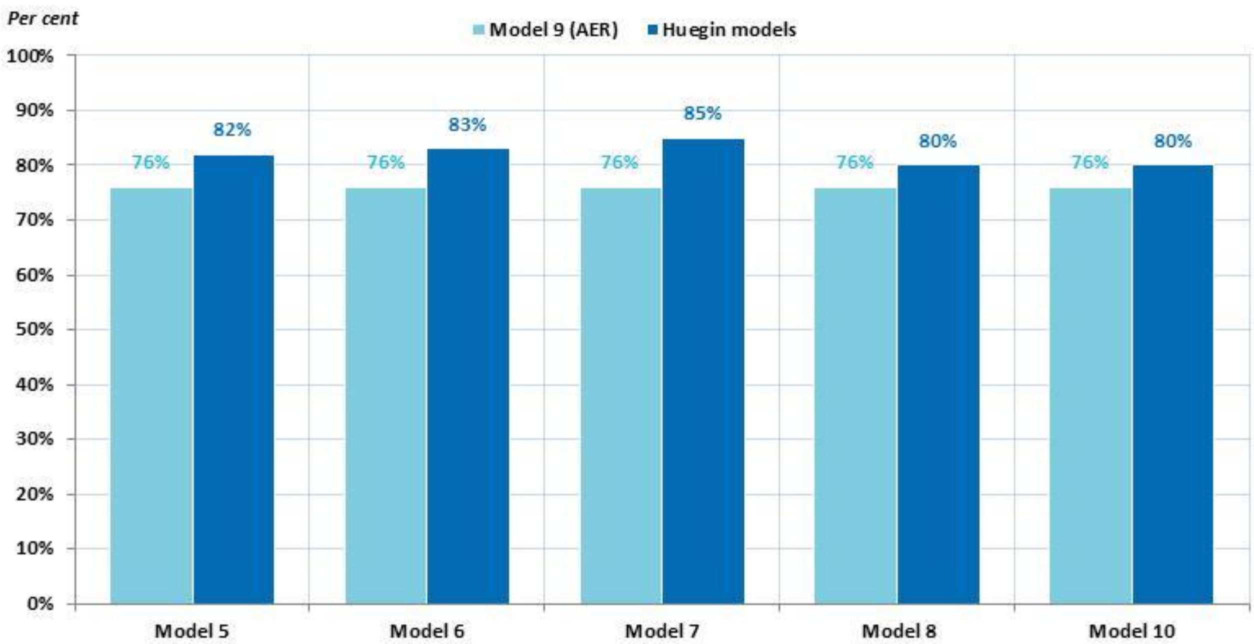
32. Huegin identifies an alternative approach to that set out in the annual benchmarking report, being the econometric method. While econometric methods were not used in the AER's annual benchmarking report, they were relied on by the AER in the New South Wales draft decisions.

33. We agree with Huegin that there are concerns with the AER's preferred econometric model (model 9 in Figure 2–4). Key areas are:

- Reasonableness and meaningfulness relating to the pooling of Australian and international data[17]
- Country dummy variables do not overcome latent heterogeneity[18]
- Selection of explanatory variables is limited to only four environmental variables[19], and
- Differences in data reporting and RIN interpretation among Australian businesses.

34. Attachment 8–4 (see section 3.4.2) discusses the above key concerns in detail and Figure 2–4 sets out the results of Huegin's econometric analysis, where our opex efficiency score ranges between 80% and 85% compared to the AER's estimate of 76%.

**Figure 2–4: Results of Huegin econometric analysis**




Source: Huegin (Attachment 8–5), Figure 13 (reproduced by JEN).

35. While Huegin's results indicate that a small gap between us and the 'frontier' business still exists in terms of opex productivity, this gap is likely be due to differences in asset lifecycles, capitalisation policies and how we balance the capex / opex trade-offs.

17 International data from the DNSPs from New Zealand and Ontario (in Canada) was also pooled.

18 The AER (through Economic Insights) recognises that there is some latent heterogeneity in the sample by including country dummy variables for New Zealand and Ontario in its preferred model. Frontier (on page 42 in its report for Networks NSW: *Review of AER's econometric models and their application in the draft determination for Networks NSW,* January 2015) notes that simply including a dummy variable will not account for differences in the relationships between cost drivers and productivity, since the dummy variable simply shifts the intercept term, without affecting the slope coefficients.

19 The AER (through Economic Insights) only identified four environmental variables (peak demand, customer connections, the share of a network underground assets and circuit length). It is assumed that any variation in opex not explained by variation in these variables related to inefficiency. Huegin (through its "*Response to the AER's draft determination on behalf of Networks NSW and ActewAGL*: *Technical response to the application of benchmarking by the AER,* January 2015, p. 42) identified other variables such as asset age, climate, regulated service standards and demographic factors.

#### 2.1.1.3 Base year prudency

36. Our base year opex is prudent[20] because we have a strong governance framework and set of internal policies that ensure we incur opex only where it is prudent to do so. Examples include:

- **Publicly available specification (PAS) 55**—this world-class accreditation indicates we have sound processes in place to facilitate compliance with asset governance frameworks (see chapter 7 and Attachment 7–2 for more information)
- **Sound budgeting and forecasting processes**—these processes facilitate proper cost control and management as well as timely management and statutory reporting consistent with accounting standards
- **Delegation of financial authority**—effective controls are in place to ensure only personnel with appropriate delegated financial authority approve expenditure
- **Efficient procurement policy and leading procurement practices**—we use outsourcing and competitive tendering with strict evaluation criteria to ensure high-quality services and market-tested prices
- **Sound recruitment policies**—including a well-documented process and a dedicated committee to approve all new employee positions, and
- **Step changes**—we assessed our current compliance and identified additional new obligations (and associated step changes) and consider alternatives available before choosing the most appropriate option to ensure we can meet our obligations and customer expectations.

## 2.2 ADJUSTING THE BASE YEAR

### 2.2.1 ADJUSTING FOR NON-RECURRENT COSTS

37. We identified four cost items that do not represent a typical year of recurrent opex. Our expected non-recurrent costs are set out in Table 2–1.

**Table 2–1: Our non-recurrent costs ($2014 and $2015, $millions)**

| Item | Description | Non-recurrent costs |
|---|---|---|
| Earth testing in non CMEN areas | This expenditure fits within our Electricity Safety Management Scheme testing program and was conducted to assess whether non-Common Multiple Earthed Neutral (**CMEN**) areas are exceeding resistance levels permitted by industry standards. | -0.20 |
| Public lighting switch removal | This expenditure will be 140% higher in 2016-20 than in 2014 due to the materially higher volumes of conductor to be removed. | +0.73 |
| EDPR regulatory costs | Separately identified as a step change due to the lumpy nature of the expenditure profile. | -2.10 |
| Loss on scrapping of assets | JEN is compensated for all cash proceeds arising | -0.39 |

[20] The AER notes (on page 43 of its *Better Regulation Forecast Expenditure Assessment Guideline*, November 2013) that "*Prudent expenditure is that which reflects the best course of action, considering available alternatives. Efficient expenditure results in the lowest cost to consumers over the long term. That is, prudent and efficient expenditure reflects the lowest long term cost to consumers for the most appropriate investment or activity required to achieve the expenditure objectives.*"

| Item | Description | Non-recurrent costs |
|---|---|---|
| | from disposal or sale of its assets. Not adjusting for this item will lead to cost over-recovery. | |
| **Total non-recurrent costs ($2014)** | | **-1.97** |
| **Total non-recurrent costs ($2015)** | | **-2.02** |

(1) These non-recurrent costs are actual expenditure incurred within our proposed base year (2014).

### 2.2.2 REMOVING CATEGORIES OF COSTS WHERE THE BASE YEAR IS NOT REPRESENTATIVE

38. We identified the following cost categories for which the use of the 'base, step and trend' method does not produce representative forecast future expenditure requirements:

- GSL payments
- Demand side management, and
- Debt raising costs[21].

39. These cost categories are removed from the base year, and a 'zero-based' methodology is applied to develop our specific forecasts.

40. Section 2.4 provides further detail on the methods we adopted for our specific forecasts.

## 2.3 TRENDING THE BASE YEAR

### 2.3.1 RATE OF CHANGE

41. Rate of change—which trends the base year forward by escalating and de-escalating the forecast to account for changes in key input costs, any output growth or productivity improvement—contributes around $35m ($2015) or 7.1% to our opex forecasts for distribution services over the 2016 regulatory period.

42. The trending of our base year opex is determined by the rate of change relationship described in Box 1–4.

**Box 1-4: Opex rate of change formula**[22]

**Annual real rate of change** = (1+∆ real price growth) x (1+∆ output growth) x (1-∆ productivity growth) - 1

The formula states that the annual change in opex in real terms is a function of:

- The forecast real increase in price growth (i.e. input cost (labour and materials) escalators)
- The expected increase in output (or the amount of work to do), and
- The expected productivity improvement associated with returns to scale, business conditions or technology.

We then applied forecast Inflation to convert our opex forecast from real to nominal dollars.

21 See section 2.5.4

22 Huegin, *Efficiency and growth for the 2016-20 regulatory period,* Jemena Electricity Networks (VIC) Ltd Productivity Study, April 2015

43. Economic Insights (**EI**) sets out the theory and precedent for this approach in its report, which the AER drew upon to determine the Victorian gas distribution businesses' opex allowances[23], and is consistent with the AER's preferred methodology.[24]

44. We propose an inflation forecast of 2.52% per annum over the 2016 regulatory period. Forecast inflation is the geometric average of the forecast annual inflation for each of the ten years from 2016 to 2025 as set out in chapter 9 and Attachment 9–2 of our regulatory proposal. This is consistent with current AER's practice[25].

45. Our forecast rate of change is set out in Table 2–2. This rate of change is applied to the overall opex amount that is not subject to specific forecasts.

**Table 2–2: Opex rate of change forecast (per cent, $2015, $millions)**

| Parameter | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|
| Rate of change (%) | 1.88% | 2.30% | 2.64% | 2.65% | 2.53% | 2.51% |
| Opex change ($m) | 1.36 | 3.05 | 5.04 | 7.09 | 9.10 | 11.15 |
| **Total over 2016-20 ($m)** | | | | | | **35.44** |

(1) The amounts represent year-on-year changes to our adjusted base year opex.
(2) The rate of change for 2015 is included because the first year of trending for our base year opex starts in 2015.
(3) The amounts for opex change are in $2015 dollars, meaning the impact of inflation (to convert to nominal dollars) is not accounted for.

### 2.3.2 REAL PRICE GROWTH

46. Real price growth contributes around $12m ($2015) or 2.3% to our opex forecasts for distribution services.

47. Our costs are affected by changes in key labour and materials costs. For labour, these include both internal and external (e.g. contractor) labour rates. For materials, these include aluminium, copper, steel, oil, concrete and wood.

48. We commissioned BIS Shrapnel (**BIS**) to forecast real changes in these labour and material costs over the next regulatory period. BIS, a well-regarded economic forecaster, combined its economic outlook for Victoria and Australia with standard forecast methods and historical data to develop reasonable forecasts. BIS's full report is included in Attachment 8–8.

49. We have used BIS's Wage Price Index (**WPI**) for real wage forecasts for the Victorian electricity, gas, water and waste services (**EGWWS**) and construction sectors as proxies for our internal and external labour costs over the 2016 regulatory period. BIS's estimate of our real price growth factors are set out in Table 2–3.

**Table 2–3: Real price growth escalation factors (per cent)**

| Parameters | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|
| **Labour real price growth:** | | | | | | |
| EGWWS WPI – Victoria (1) | 0.48% | 0.88% | 1.35% | 1.76% | 2.11% | 1.81% |
| Construction WPI – Victoria (1) | 0.78% | 1.19% | 1.63% | 1.49% | 1.61% | 1.92% |

23 AER, *Access arrangement final decision, Envestra Ltd 2013–17, Part 1*, March 2013, chapter 7

24 AER, *Better Regulation Expenditure Forecast Assessment Guideline,* November 2013

25 AER, *Draft decision for Jemena Gas Networks (NSW) Ltd Access Arrangement 2015-20, Attachment 3: Rate of return*, November 2014, p. 161.

| Parameters | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|
| **Material real price growth:** | | | | | | |
| Aluminium | 9.52% | 7.98% | 8.23% | 5.15% | -7.01% | -5.21% |
| Copper | 0.44% | 3.46% | 7.68% | 2.13% | -9.99% | -6.09% |
| Steel | 4.81% | 4.72% | 2.99% | 2.71% | -11.01% | -3.36% |
| Oil | -1.91% | -1.11% | 4.32% | 2.54% | -7.66% | -4.97% |
| Concrete | -1.12% | -0.95% | -2.00% | -4.90% | -3.20% | 1.30% |
| Wood | 2.50% | 2.15% | 1.70% | 0.90% | 2.20% | 3.90% |
| General materials (2) | 2.37% | 2.71% | 3.82% | 1.42% | -6.11% | -2.41% |
| Other (3) | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |

(1) For labour, we have applied the EGWWS WPI and the Construction WPI to its internal and external labour cost forecasts respectively.
(2) For materials, we have applied a blended rate—'general materials'—using a simple average of all commodities indexes.
(3) For the 'Other' category, we assume no real cost escalators (i.e. these costs only escalate by inflation).

50. The 'blended' real price growth factor, which takes into account the 'general materials' growth rate and the associated escalation weights, is set out in Table 2–4.

**Table 2–4: Blended real price growth escalation factors ($2015)**

| Parameter | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|
| Real price growth factor (%) | 0.41% | 0.68% | 1.02% | 1.13% | 1.03% | 1.06% |
| Opex change ($m) | 0.30 | 0.78 | 1.51 | 2.33 | 3.09 | 3.87 |
| **Total over 2016-20 ($m)** | | | | | | **11.58** |

51. We then applied a weighted average method to derive a 'blended' rate of change[26] for real price growth, by multiplying the escalation weights (i.e. breakdown of each opex category in either internal labour, external labour, general materials or other) by the real price growth factors provided by BIS.

### 2.3.3 OUTPUT GROWTH

52. Output growth contributes around $36m ($2015) or 7.3% to our opex forecasts for distribution services.

53. Many of our operating and maintenance activities (including associated costs) will grow in line with our customer base and network's system physical capacity, specifically:

- Growth in our customer base means we will be required to increase our support activities such as billing enquiries and customer service, as well as our maintenance (including emergency response) costs to maintain the service levels our customers expect, and
- Growth in the system physical capacity of our network (estimated as a product of distribution transformer capacity and network line length) means we will need to increase our maintenance expenditure to accordingly maintain and support the expanded network.

26 Blended rate of change for real price growth = $\sum(Wi \times Ei)$, where Wi = relative weight of each opex component (e.g. labour vs. materials) and Ei = input cost escalation factor for that component.

54. To determine reasonable forecasts of growth in customer connections and system physical capacity, we have drawn upon expertise from ACIL Allen Consulting Group (**ACIL**) and our internal engineering or network planning teams respectively. ACIL's full report is included as Attachment 3–3.

55. Our output growth forecasts are shown in Table 2–5.

**Table 2–5: Opex output growth forecast ($2015)**

| Parameter | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|
| Output growth (%) | 2.33% | 2.57% | 2.56% | 2.39% | 2.37% | 2.28% |
| Opex change ($m) | 1.67 | 3.54 | 5.45 | 7.28 | 9.13 | 10.95 |
| **Total over 2016-20 ($m)** | | | | | | **36.35** |

(1) Output growth is estimated by multiplying the annual year-on-year changes (%) of the output drivers (customer numbers and system physical capacity) by the relevant weights (or cross elasticity) between the output drivers, sourced from Huegin.

### 2.3.4 PRODUCTIVITY GROWTH

56. Productivity growth *reduces* our forecast opex costs for distribution services by around $12m ($2015) or 2.5%.

57. As noted in section 2.1.1.2 we engaged Huegin[27] to estimate our opex PFP forecasts to derive the level of opex productivity we are expected to achieve over the 2016 regulatory period. Huegin's approach used industry level data to establish a robust model of productivity changes in electricity networks.

58. The model—which departs from the AER's approach (where appropriate—was then applied to estimate our opex PFP forecast. More detail is set out in Huegin's expert report (see Attachment 8–5).

59. This approach is consistent with the AER's forecast expenditure assessment guideline[28] which requires that our forecast opex reflects the expected improvements in productivity across our industry.

60. This analysis indicates that we are expected to achieve productivity improvements averaging 0.89 per cent per annum over the 2016 regulatory period (see Table 2–6). These forecast productivity gains are passed through to our customers as savings and reflect our commitment to efficiently manage our business.

**Table 2–6: Opex partial factor productivity forecast (per cent, $2015, $millions)**

| Parameter | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|
| Opex PFP (%) | 0.85% | 0.94% | 0.93% | 0.87% | 0.86% | 0.83% |
| Opex change ($m) | -0.61 | -1.27 | -1.92 | -2.52 | -3.11 | -3.67 |
| **Total over 2016-20 ($m)** | | | | | | **-12.49** |

#### 2.3.4.1 Scale efficiency

61. Output growth does not result in a one for one increase in opex requirement, i.e. a 1% increase in output growth does not result in a 1% increase in opex. This is due to economies of scale, which allow us to realise efficiencies from an expanded network, and ultimately passed on to customers as savings.

27 Huegin, *Efficiency and growth for the 2016-20 regulatory period,* Jemena Electricity Networks (VIC) Ltd Productivity Study, April 2015.

28 NER cl 4.2.3, AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution,* Nov, 2013.

62. The economies of scale that we are expected to realise over the 2016 regulatory period are factored into our opex PFP forecast[29].

63. Huegin's model also takes into account a range of other factors such as capital interaction effects, the impact of changes in operating environment factors, technological change and changes in efficiency levels, to ensure we capture the full scale effect in its calculations.

## 2.4 ADJUSTING FOR STEP CHANGES

64. Step changes include increases or decreases in costs due to new regulatory obligations, or changes in the operating environment that are outside our control. These also include changes in costs, resulting from opex to capex trade-off, that provide a benefit to customers or initiatives that are sought by our customers.

65. These costs reflect forecast prudent and efficient opex not captured by the base year expenditure or trend escalation, where we assessed alternative options to ensure we act in the long-term interests of our customers. Insufficient funding for these step changes will deny us a reasonable opportunity to recover our efficient costs.

66. We have identified items that will affect our future opex that are not in our base year. These items represent step changes in our operating environment and regulatory obligations—for example, changes in standards, compliance requirements, and new asset types with new operational and maintenance requirements.

67. We have added step changes amounting to approximately $30m ($2015) to our trended base year opex forecast. Table 2–7 sets out our proposed step changes.

68. Attachment 8–6 provides further details on the individual step change items, their causation and the basis of their forecast costs.

**Table 2–7: Step changes included in forecast opex ($2015, $millions)**

| Change factor | Reason | Five-year total |
|---|---|---|
| Enhanced inspection and maintenance program of aging assets | To meet new safety and technical standards, and target assets that are in need of replacement to maintain our safety and service | 11.41 |
| Regulatory proposal | To meet the requirements of running the 2021-25 price review (including drafting the relevant regulatory proposal documents) | 8.03 |
| Vulnerable customer assistance | To assist vulnerable customers in response to customer preferences | 1.01 |
| Vegetation Management | To comply with changes in Electricity Safety Amendment (Bushfire Mitigation) Act 2014 and proposed Electricity Safety (Electric Line Clearance) Regulations 2015 | 5.63 |
| Targeted Demand Response | Implementing a demand response (DR) programme to mitigate network constraints and limit potential risk of supply interruption to customers | 0.71 |
| Insurance premiums | To prudently and effectively manage the emerging risks posed to our business | 0.17 |

29 Huegin states that its econometric cost function analysis controlled, among other things, for these differences (see Attachment 8–5).

| Change factor | Reason | Five-year total |
|---|---|---|
| Customer, stakeholder and community engagement | To design and deliver customer engagement with respect to best practice principles and identification of relevant concerns in preparing the 2016 regulatory proposal | 0.93 |
| Implementing new tariffs | On 27 November 2014, the AEMC made a rule that introduced new pricing arrangements to the NER. The intent of the rule change is to drive cost-reflective network prices and improve the transparency of distributors pricing information. This has created new obligations on distribution businesses, including JEN. | 2.46 |
| **Total step changes** | | **30.34** |

(1) The first step change consolidates five individual step changes, which relate to (i) service inspection and testing program, (ii) overhead switch inspection, (iii) pole top early detection system trial, (iv) Energy Safe Victoria (**ESV**) or Victorian Electricity Supply Industry (**VESI**) code of practice changes and (v) enclosed substation inspection and rectification program. These step changes are all considered to be maintenance-related obligations.

(2) The 'Targeted Demand Response' step change is separately included as a specific forecast under the 'demand side management' category, meaning there is no double counting in our opex forecasts.

## 2.5 ADDING SPECIFIC YEAR-ON-YEAR FORECASTS

69. JEN has then added to its trended opex forecast, its specific year-on-year forecasts, namely:

- GSL payments (see section 2.5.1)
- Demand side management (see section 2.5.2)
- Self-insurance (see section 2.5.3), and
- Debt raising costs (see section 2.5.5).

### 2.5.1 GSL PAYMENTS

70. GSL payments relate to some distribution services we provide. The GSL service standards and payments are currently set out in the Electricity Distribution Code in Victoria. There are times when, despite our best efforts, we are unable to meet the guaranteed service levels in the codes. When this occurs, we will pay GSL payments to customers entitled to receive the payments.

71. Table 2–8 sets out our forecast GSL payments for each year of the 2016 regulatory period.

**Table 2–8: Forecast GSL payments ($2015, $millions)**

| | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| GSL payments | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 |
| **Total over 2016-20 ($m)** | | | | | **0.35** |

72. We have forecast that our GSL payments will remain unchanged (in real terms) from the amounts within our base year opex over the 2016 regulatory period as the rate of payment is expected to remain constant.

### 2.5.2 DEMAND SIDE MANAGEMENT

73. There are two components of the forecast demand side management costs:

- Energy portal maintenance and demand response field trials, and
- Demand management opex for capex trade-off.

#### 2.5.2.1 Energy portal maintenance and demand response field trials

74. This activity relates to the maintenance of the energy portal that we developed to assist our customers understand and manage their consumption and some demand response field trials that we initiated in 2014. We have forecast this component will remain unchanged (in real terms) from the amounts incurred in 2014 over the 2016 regulatory period.

#### 2.5.2.2 Demand management opex for capex trade-off

75. This relates a step change for operating costs associated with two specific demand response (**DR**) opex programs to mitigate two network constraints and limit potential risk of supply interruption to customers, which would otherwise need to be addressed through a capex response. The areas are:

- Footscray East, and
- North Heidelberg and Watsonia.

76. The long-term solutions for these constraints require network augmentation works. However, by deploying DR programs, network augmentation works can be prudently deferred to the 2021-25 regulatory period. JEN must plan a targeted DR program for the two constrained areas.

77. We used a 'zero-based' methodology to derive the cost estimates (see Attachment 8–6 for more detail).

78. Table 2–9 sets out the forecast demand side management costs for each year of the 2016 regulatory period.

**Table 2–9: Forecast demand side management costs ($2015, $millions)**

| | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| Energy portal maintenance and demand response field trials ($m) | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 |
| Demand management opex for capex trade-off ($m)[30] | 0.11 | 0.15 | 0.15 | 0.15 | 0.15 |
| **Total over 2016-20 ($m)** | **0.17** | **0.22** | **0.22** | **0.22** | **0.22** |

### 2.5.3 SELF-INSURANCE

79. We insure ourselves through third parties against a number of uncontrollable asymmetric risks. For some specific risks, third party insurance policies may not be available or represent commercially prudent or viable options. In these cases, a business may opt to self-insure against these risks, meaning it would incur the costs in the event these risks materialise.

80. We have not proposed any self-insurance costs for the 2016 regulatory period.

[30] This is also included in the full list of step changes that we propose for the 2016 regulatory period.

### 2.5.4 DEBT RAISING COSTS

81. Debt raising costs are the costs of issuing debt, including the costs of maintaining an investment credit rating needed to issue this debt. Consistent with standard regulatory practice, we propose estimating these costs for a benchmark efficient entity with the same characteristics as our network, including:

- The forecast regulatory asset base (**RAB**) over the next regulatory period, and
- Leverage of 60%, consistent with our proposed rate of return (see chapter 9 of our regulatory proposal).

82. Incenta Economic Consulting (**Incenta**) states that there are least three key debt raising costs:[31]

- **Transaction costs**—the costs of issuing bonds with a 10 year maturity, such as legal, investment banking and rating agency fees
- **Liquidity costs**—the costs of establishing and maintaining minimum bank facilities to cover any adverse market conditions, as required by Standard & Poor's (**S&P**) to maintain an investment grade credit rating. This requirement is typical of other major rating agencies. Maintaining an investment grade credit rating is consistent with the credit ratings assumed in the AER's rate of return guideline (BBB+) and proposed by JEN (BBB) for the benchmark entity, and
- **Early refinancing costs**—the costs of refinancing debt at least three months ahead of when it matures, again as required by S&P to maintain an investment grade credit rating.

83. Each of these are financing costs—considered prudent and efficient—that a benchmark entity would incur to issue debt to fund investment in its assets. As such, we consider that each cost should form part of our debt raising cost forecast—a position supported by Incenta.

84. We used benchmark debt raising cost estimate of 0.18% of outstanding debt per year over the 2016 regulatory period. We consider this a reasonable estimate that reflects efficient financing costs.

85. Taking this estimate, we forecast debt raising costs over the 2016 regulatory period using our post-tax revenue model (see Attachment 6–1)—with the resulting forecast set out in Table 2–10. We report these costs as 'Other' when including them in our opex forecast. Further detail is included in Attachments 8–7 and 9–2.

**Table 2–10: Forecast debt raising costs ($2015, $millions)**

| | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| Debt raising costs | 1.27 | 1.34 | 1.43 | 1.51 | 1.58 |
| **Total over 2016-20 ($m)** | | | | | **7.13** |

### 2.5.5 EQUITY RAISING COSTS

86. Equity raising costs are paid by an entity when it raises equity either internally (via reinvested dividends) or externally from new or existing shareholders. New equity is often needed to maintain a given capital structure (i.e. 60% leverage) and credit rating (i.e. BBB as proposed by JEN or BBB+ as proposed by the AER), especially when capital expenditure grows faster than revenues. The costs of raising new equity include lawyers and investment banking fees.

[31] Incenta Economic Consulting, *Debt raising transaction costs – Jemena*, June 2014, p. 3, appendix 7.8.

87. We propose estimating equity raising costs for a benchmark efficient entity with the same characteristics as JEN, including:

- Forecast RAB and cash flows over the next regulatory period
- Leverage of 60%, and
- Dividend payout ratio of 70%, consistent with our proposed value of imputation credits (see chapter 6 of our regulatory proposal).

88. Consistent with recent AER decisions, we propose benchmark efficient equity raising costs of:

- 1% on equity raised internally (through dividend reinvestment)—assuming a dividend payout of 70% and dividend reinvestment take-up rate of 30%, and
- 3% on equity raised externally.

89. We also propose applying these percentages to our forecast RAB for distribution services (and assuming 60% leverage) using the AER's method,[32] and capitalising any equity raising costs to the RAB at the start of the next regulatory period.

90. Our calculation of equity raising costs over the 2016 regulatory period is set out in our post-tax revenue model in Attachment 6–1. Our proposed value of $3.2m ($2015) will change if forecast costs and revenue change.

### 2.5.6 SERVICE RECLASSIFICATION

91. There is a portion of costs that is now included in our forecast opex for distribution services:

- Metering services
- Supply abolishment (up to 100 amps)

92. Through its final Framework and Approach paper[33], the AER has classified:

- *Metering services* as an ACS activity, but a portion of these costs, currently recovered through the CROIC under a transitionary arrangement—but relating to distribution services—is now included in our distribution services opex
- *Supply abolishment (up to 100 amps)* as a distribution service instead of being currently an ACS activity in the 2011 regulatory period.

#### 2.5.6.1 Metering services

93. The costs we incur to provide metering services including the smart meters that we rolled out up to 2014 are currently recovered through the CROIC up to 31 December 2015 (see Box 3-1 of our regulatory proposal).

94. We applied the base, step and trend approach to forecast these costs:

- *First*, we used the 2014 opex for the provision of metering services and adjusted it for non-recurrent costs
- *Second*, we reclassified the base year opex into costs relating to either distribution or metering services

[32] AER, *Post-tax revenue model, October 2014 (change to final PTRM)*, January 2015

[33] AER, *Final Framework and approach for the Victorian Electricity Distributors*, 24 October 2014, p. 43

- *Third*, we trended the two components using the 'blended' rate of change for metering services, and
- *Fourth*, we included the distribution services portion into our opex forecast from 2016 onwards.

#### 2.5.6.2 Supply abolishment services (up to 100 amps)

95. This service is provided by dispatching a service truck to remove the supply asset. We consider the appropriate effort, skill set of the crews and vehicle required to undertake this work is similar to the truck visit service.

96. Similar to metering services costs, we applied the base, step and trend approach to forecast these costs. We do not foresee any other step changes that will affect our opex for metering services and the supply abolishment (up to 100 amps) over the 2016 regulatory period.

97. Attachment 8–3 illustrates our approach. Table 2–11 sets out the forecast portion of metering services costs and supply abolishment (up to 100 amps) that are reclassified.

**Table 2–11: Service reclassification – to distribution services ($2015, $millions)**

| Service reclassification | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| Metering | 11.42 | 11.76 | 12.14 | 12.58 | 12.99 |
| Supply abolishment (up to 100 amps) | 0.57 | 0.58 | 0.60 | 0.62 | 0.64 |
| **Total over 2016-20 ($m)** | **11.99** | **12.35** | **12.75** | **13.19** | **13.63** |

# 3. OUR OPEX FORECAST

## 3.1 DISTRIBUTION SERVICES

98. Table 3–1 summarises our forecast opex for distribution services over the 2016 regulatory period.

**Table 3–1: Forecast opex for distribution services ($2015, $millions)**

| Distribution services opex | 2016 | 2017 | 2018 | 2019 | 2020 | Total |
|---|---|---|---|---|---|---|
| **Network maintenance** | **19.31** | **19.64** | **20.07** | **20.50** | **20.94** | **100.46** |
| Routine maintenance | 6.17 | 6.28 | 6.40 | 6.51 | 6.63 | **31.98** |
| Non-routine maintenance | 3.92 | 4.02 | 4.12 | 4.22 | 4.32 | **20.62** |
| Emergency response | 3.84 | 3.94 | 4.05 | 4.15 | 4.25 | **20.24** |
| Vegetation management | 5.38 | 5.39 | 5.51 | 5.62 | 5.73 | **27.62** |
| **Network operating** | **56.36** | **55.40** | **57.50** | **61.11** | **63.47** | **293.84** |
| Network overheads | 34.28 | 32.73 | 34.22 | 37.23 | 38.98 | **177.43** |
| Corporate overheads (excluding IT) | 22.08 | 22.67 | 23.28 | 23.88 | 24.49 | **116.41** |
| **Non-network** | **16.62** | **17.08** | **17.57** | **18.08** | **18.59** | **87.95** |
| Information technology (IT) | 11.75 | 12.08 | 12.44 | 12.82 | 13.19 | **62.28** |
| Motor vehicles | 0.57 | 0.59 | 0.60 | 0.62 | 0.63 | **3.01** |
| Buildings and property | 4.30 | 4.42 | 4.53 | 4.65 | 4.76 | **22.66** |
| **Other** | **3.08** | **3.23** | **3.36** | **3.48** | **3.60** | **16.76** |
| Levies (incl. licence fees) | 1.56 | 1.60 | 1.65 | 1.69 | 1.73 | **8.24** |
| GSL payments | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | **0.35** |
| Demand-side management | 0.17 | 0.22 | 0.22 | 0.22 | 0.22 | **1.04** |
| Self-insurance | - | - | - | - | - | **-** |
| Debt raising costs | 1.27 | 1.34 | 1.43 | 1.50 | 1.58 | **7.13** |
| **Total forecast opex** | **95.37** | **95.36** | **98.51** | **103.18** | **106.60** | **499.01** |

(1) The forecast distribution services opex includes a portion of costs of metering services and supply abolishment (up to 100 amps). Section 2.5.6 provides more detail.

## 3.2 METERING SERVICES

99. Table 3–2 summarises our forecast opex for distribution services over the 2016 regulatory period.

**Table 3–2: Forecast opex for metering services ($2015, $millions)**

| Metering services opex | 2016 | 2017 | 2018 | 2019 | 2020 | Total |
|---|---|---|---|---|---|---|
| **Network maintenance** | **1.03** | **1.06** | **1.09** | **1.13** | **1.17** | **5.47** |
| Routine maintenance | 1.03 | 1.06 | 1.09 | 1.13 | 1.17 | **5.47** |
| Non-routine maintenance | - | - | - | - | - | **-** |
| Emergency response | - | - | - | - | - | **-** |
| Vegetation management | - | - | - | - | - | **-** |
| **Network operating** | **4.65** | **4.79** | **4.94** | **5.12** | **5.29** | **24.79** |
| Network overheads | 3.80 | 3.92 | 4.04 | 4.19 | 4.32 | **20.27** |
| Corporate overheads (excluding IT) | 0.85 | 0.87 | 0.90 | 0.93 | 0.96 | **4.52** |
| **Non-network** | **4.87** | **5.02** | **5.18** | **5.37** | **5.54** | **25.99** |
| Information technology (IT) | 4.87 | 5.02 | 5.18 | 5.37 | 5.54 | **25.99** |
| Motor vehicles | - | - | - | - | - | **-** |
| Buildings and property | - | - | - | - | - | **-** |
| **Other** | **0.26** | **0.21** | **0.18** | **0.16** | **0.14** | **0.95** |
| Levies (incl. licence fees) | - | - | - | - | - | **-** |
| GSL payments | - | - | - | - | - | **-** |
| Demand-side management | - | - | - | - | - | **-** |
| Self-insurance | - | - | - | - | - | **-** |
| Debt raising costs | 0.13 | 0.10 | 0.09 | 0.08 | 0.07 | **0.47** |
| **Total forecast opex** | **10.68** | **10.97** | **11.31** | **11.70** | **12.07** | **56.73** |

(1) The forecast metering services opex excludes a portion of costs of metering services that is now included in distribution services. Section 2.5.6 provides more detail.

# 4. COMPLIANCE WITH THE NER

100. Our opex forecasts are prepared on a reasonable basis and have been developed to comply with the operating expenditure objectives and operating expenditure criteria and to address the operating expenditure factors[34] along with other NER criteria for standard control services.

## 4.1 OPERATING EXPENDITURE OBJECTIVES

101. We have established our forecasts to comply with the operating expenditure objectives specified in the NER. This was primarily achieved by:

- Examining the proposed base year costs incurred in meeting our current service level and regulatory obligations
- Assessing the sufficiency of our current compliance with safety, regulatory and compliance obligations to identify step changes for corrective actions
- Assessing foreseeable new or changed obligations that will affect our operating activities and costs to identify step changes, and
- Incorporating escalation or de-escalation for the opex the rate of change including real price growth, output growth and productivity improvement.

102. Table 4–1 summarises how we have complied with the operating expenditure objectives.

**Table 4–1: Our compliance with the operating expenditure objectives**

| Operating expenditure objective | Rule | Our compliance |
|---|---|---|
| Meet or manage the expected demand for standard control services | 6.5.6(a)(1) | We have trended our proposed base year opex to account for expected changes in output growth drivers such as customer numbers and our network's system physical capacity (see section 2.3.3). |
| Comply with all applicable regulatory obligations or requirements associated with the provision of standard control services | 6.5.6(a)(2) | We have assessed our current compliance (and associated base year costs), as well as identifying additional new obligations that we expect to be in place over the 2016 regulatory period (see section 2.4 for our list of proposed step changes). |
| Maintain the quality, reliability and security of supply of standard control services | 6.5.6(a)(3) | We have proactively engaged with our consumers to first understand the level of service they value (see Attachment 4–1), to assist the preparation of our comprehensive 7-year asset management plan (see Attachment 7–5), and undertook a detailed service deliverability assessment (see Attachment 7–8) to ensure we are in a position to meet these requirements. |
| Maintain the reliability, safety and security of a distribution system through the standard control services | 6.5.6(a)(4) | |

34 NER cl. 6.5.6(a)

## 4.2 OPERATING EXPENDITURE FACTORS

103. The NER[35] set out the factors that the AER must have regards to when deciding whether or not to approve our opex forecast.

104. Table 4–2 summarises points we consider relevant to these factors.

**Table 4–2: Our consideration of the operating expenditure factors**

| Operating expenditure factor | Rule | Our consideration |
|---|---|---|
| [deleted] | 6.5.6(e)(1) | |
| [deleted] | 6.5.6(e)(2) | |
| [deleted] | 6.5.6(e)(3) | |
| The most recent annual benchmarking report that has been published under rule 6.27 and the benchmark operating expenditure by an efficient Distribution Network Service Provider over the regulatory control period | 6.5.6(e)(4) | We have carefully reviewed the AER's most recent annual benchmarking report and other relevant measures of benchmark opex that would be incurred by an efficient distribution network service provider. We fully support the use of benchmarking as useful cross-check information, but not in a deterministic way to set expenditure allowances. In our regulatory proposal, we included the following relevant documents:<br>– **Attachment 8–4**, which summarises our view on the role of benchmarking in assessing the opex efficiency, and<br>– **Attachment 8–5** (from Huegin), which assesses our historical opex performance over time. |
| The actual and expected operating expenditure of the Distribution Network Service Provider during any preceding regulatory control periods | 6.5.6(e)(5) | We have included our historical expenditure performance for the 2011 regulatory period in Attachment 8–1 and section 2.1.1.1 . For periods prior to the 2011 regulatory period, we reported these in the economic and category analysis benchmarking regulatory information notices (**RINs**). |
| The extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the Distribution Network Service Provider in the course of its engagement with electricity consumers | 6.5.6(e)(5A) | We have proactively engaged with our consumers to first understand the level of service they value (see Attachment 4–1). |

35 NER cl. 6.5.6(e)

| Operating expenditure factor | Rule | Our consideration |
|---|---|---|
| The relative prices of operating and capital inputs | 6.5.6(e)(6) | We rely on lifecycle management planning for each asset, which considers all strategies and options over the entire asset life from planning to disposal to deliver the lowest sustainable cost over the long run.<br>Lifecycle management focuses on ensuring effectiveness and efficiency in maintenance (opex) and replacement (capex) of the network asserts based on reliability centred maintenance analysis and considers issues of safety, cost, risk and reliability.<br>Additionally, we relied upon the same input real cost escalators for both opex and capex (see section 2.3.2). |
| The substitution possibilities between operating and capital expenditure | 6.5.6(e)(7) | We have considered these opportunities and have proposed:<br>– An enhanced asset inspection program (opex) to complement the asset replacement strategy (capex) (see Attachment 2–1), and<br>– Propose a step change in relation to demand management opex for capex trade-off (see Attachment 8–6). |
| Whether the operating expenditure forecast is consistent with any incentive schemes or schemes that apply to the Distribution Network Service Provider under clauses 6.5.8 or 6.6.2 to 6.6.4 | 6.5.6(e)(8) | Our private ownership—along with our consumers' expectations and the regulatory framework—provide us with strong incentives to act prudently and efficiently when assessing our expenditure. The two significant schemes that our opex forecast consider are the EBSS and the service target performance incentive scheme (**STPIS**), and we are committed to both outperform our regulatory allowances over time. We:<br>– Support both schemes and appreciate that the STPIS rewards any improvement in reliability and service levels (see Attachment 5–3)<br>– Note that our opex forecasts are required to maintain the reliability, quality and security of supply (as per NER clause 6.5.6(a)(3)), and not improve these. As a result, we did not propose any step changes to improve these standards. |
| The extent the operating expenditure forecast is preferable to arrangements with a person other than the Distribution Network Service Provider that, in the opinion of the AER, do not reflect arm's length terms | 6.5.6(e)(9) | We have established outsourcing arrangements that reflect prudent commercial terms (see our response to section 19 of the EDPR RIN). |
| Whether the operating expenditure forecast includes an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b) | 6.5.6(e)(9A) | Our proposed opex forecast does not include an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b) |
| The extent the Distribution Network Service Provider has considered and made provision for, efficient and prudent non-network alternatives | 6.5.6(e)(10) | We have considered these non-network alternatives and proposed a step change in relation to demand management opex for capex trade-off (see Attachment 8–6). More detail is included in our response 21.2 of Schedule 1 of the EDPR RIN. |

| Operating expenditure factor | Rule | Our consideration |
|---|---|---|
| Any relevant final project assessment report (as defined in clause 5.10.2) published under clause 5.17.4(o), (p), or (s) | 6.5.6(e)(11) | We do not consider this factor to be relevant to our opex forecast over the 2016 regulatory period. |
| Any other factor the AER considers relevant and which the AER has notified the Distribution Network Service Provider in writing, prior to the submission of its revised regulatory proposal under clause 6.10.3 is an operating expenditure factor | 6.5.6(e)(12) | The AER did not notify us with any other factor, not mentioned above, that it considers relevant. |

## 4.3 FIXED AND VARIABLE COMPONENTS

105. In our building block proposal, we must outline our fixed and variable operating costs[36]. The NER does not specifically stipulate a horizon to use. The forecast horizon of 2016 to 2020 may be characterised in economic terms as the short run. This is because in this time period, we will incur both:

- Variable costs that will change as our output of customer numbers and our network's system physical capacity changes, and
- Fixed costs which by their nature will be incurred regardless of movements in our outputs.

106. The fixed and variable costs may be considered end points on a range of cost characteristics. Within this range, we will incur costs that vary on a one-for-one basis with certain outputs as well as costs that will vary in a stepped nature. Notwithstanding this, Table 4–3 shows those operating activities for which our costs may broadly be characterised as either variable or largely fixed. We do not have access to information in a form suitable for identifying fixed and variable costs for each of our opex category.

**Table 4–3: Fixed and variable opex activities**

| Nature of costs | Examples of opex activities |
|---|---|
| Fixed | Corporate functions such as finance, regulatory management, human resources, legal and business support services<br>Engineering asset management functions<br>License fees |
| Variable | Network planned maintenance costs<br>Emergency response to unplanned maintenance requirements<br>Customer service costs such as those provided through the customer call centre |

(1) Classification of 'fixed costs' does not mean that these costs will not experience cost escalation over a given period. For example, a fixed activity may involve five full time equivalent (**FTE**) staff. While the FTE count may be fixed regardless of output growth, we would still reasonably expect to incur cost growth due to wages growth for those five FTEs.

36 NER, Cl. S6.1.2(1)(iii) .