Draft Decision

Multinet Gas Networks
Access Arrangement 2023 to 2028

(1 July 2023 to 30 June 2028)

Attachment 6
Operating expenditure

December 2022

AUSTRALIAN ENERGY REGULATOR

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Note

This attachment forms part of the AER's draft decision on the access arrangement that will apply to Multinet Gas Networks (MGN) for the 2023–28 access arrangement period. It should be read with all other parts of the draft decision.

The draft decision includes the following documents:

Overview

Attachment 1 – Services covered by the access arrangement

Attachment 2 – Capital base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency carryover mechanism

Attachment 9 – Reference tariff setting

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Attachment 11 – Non-tariff components

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6 Operating expenditure

Operating expenditure (opex) is the operating, maintenance and other non-capital expenses, incurred in the provision of pipeline services. Forecast opex is one of the building blocks we use to determine a service provider's total revenue requirement.

This attachment outlines our assessment of Multinet Gas Networks' (MGN's) proposed opex forecast for the 2023–28 access arrangement period.

6.1 Draft decision

Our draft decision is to accept MGN's total opex forecast of $399.4 million ($2022–23), excluding ancillary reference services (ARS) and including debt raising costs.[1] This is because our alternative estimate of $391.8 million ($2022–23) is not materially different ($7.5 million ($2022–23), or 1.9% lower) from MGN's total opex forecast proposal. Therefore, we consider that MGN's total opex forecast satisfies the opex criteria,[2] and satisfies the criteria for forecasts and estimates.[3]

Our draft decision is:

- $47.2 million ($2022–23), or 10.6%, lower than the opex forecast we approved in our final decision for the 2018–22 period.
- $52.7 million ($2022–23), or 15.2%, higher than MGN's actual (and estimated) opex in the 2018–22 period.

After its initial proposal in July 2022, MGN submitted an addendum in September 2022, to reflect changes to estimates following release of the Victorian Government's *Gas Substitution Roadmap.* From an opex perspective, this primarily impacted the trend forecasts including MGN's output and productivity growth forecasts. We have considered this updated proposal, and the opex forecast it contained, in making our draft decision to accept the proposed opex forecast.

Table 6.1 sets out MGN's updated opex proposal, our alternative estimate for the draft decision and the difference between these forecasts.

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1 MGN, 2*023–28 Revisions to final plan – Attachment 8.1A – Opex Forecast Model*, September 2022; AER Analysis. Note: These costs reflect those in the updated initial proposal MGN submitted on 2 September 2022 and as with all subsequent opex costs are in $2022–23.

2 NGR, r. 91.

3 NGR, r. 74.

Table 6.1 AER's alternative estimate compared to MGN's updated opex proposal ($million, 2022–23)

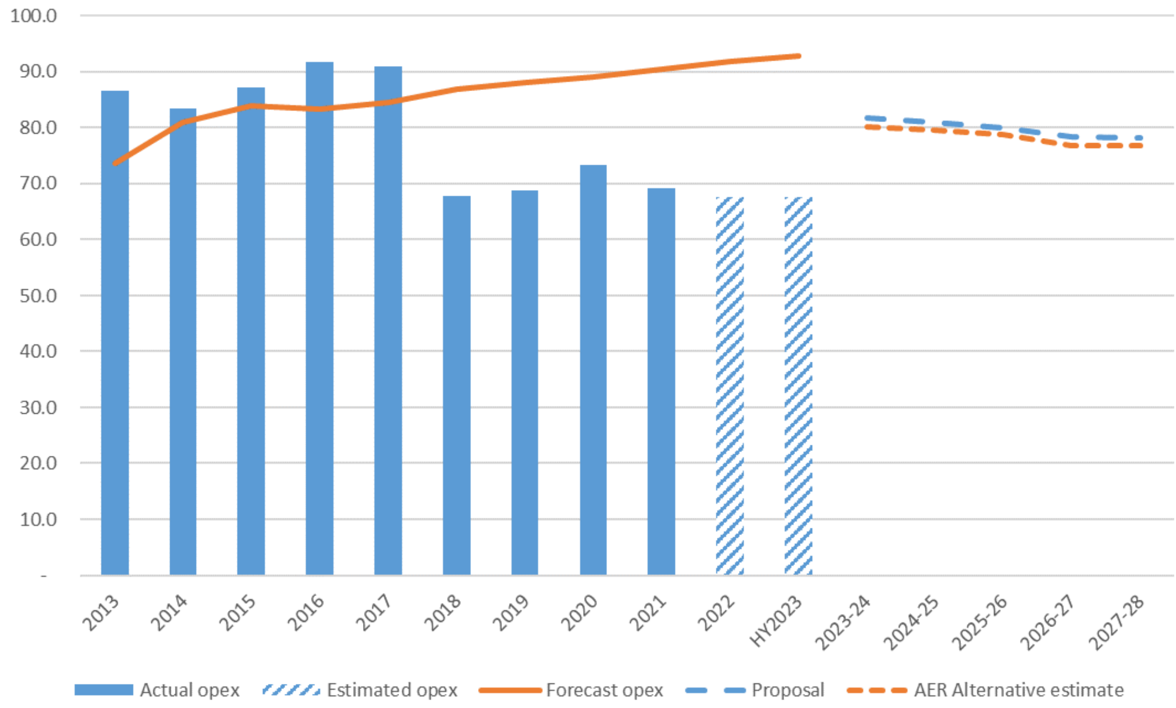
	MGN's updated proposal	AER alternative estimate	Difference
Base (reported opex in 2021)	**339.2**	**345.8**	**6.5**
Base year adjustments	**9.8**	**10.0**	**0.2**
Remove category specific costs	**7.3**	**7.5**	**0.2**
Final year increment	**22.4**	**11.4**	**–11.1**
Trend: Price growth	5.1	7.9	2.8
Trend: Output growth	–11.0	–11.0	0.0
Trend: Productivity growth	–	–	–
Total trend	**–5.9**	**–3.0**	**2.8**
Capital expenditure to opex	11.2	11.2	–
Cyber security	3.6	–	–3.6
Renewable gas communication and education	3.0	–	–3.0
Total step changes	**17.9**	**11.2**	**–6.6**
Category specific forecasts	**4.8**	**4.9**	**0.1**
Total opex (excluding debt raising costs)	**395.6**	**387.8**	**–7.9**
Debt raising costs	**3.7**	**4.0**	**0.3**
Total opex (including debt raising costs)	**399.4**	**391.8**	**–7.3**
Percentage difference to proposal			**–1.9%**

Source: MGN, *2023–28 Revisions to final plan – Attachment 8.1A – Opex Forecast Model*, September 2022; AER analysis.

Note: Numbers may not add up to total due to rounding. Differences of '0.0' and '–0.0' represent small variances and '–' represents no variance.

In Figure 6.1 we compare our alternative estimate of opex to MGN's proposal for the next access arrangement period. We also show the forecasts we approved for the last two access arrangement periods and MGN's actual and estimated opex.

Figure 6.1 Historical and forecast opex ($million, 2022–23)



Source: MGN, *Regulatory accounts 2013 to 2021*; MGN, 2023–28 *Revisions to final plan – Attachment 8.1A – Opex Forecast Model*, September 2022; AER, *MGN Access arrangement – PTRM* (multiple periods: 2013–17, 2018–22, 2023–28); AER analysis.

Note: Includes debt raising costs and movements in provisions.

While there is not a material difference between our alternative estimate of total opex and MGN's proposed opex, we have arrived at our alternative estimate in a different way to MGN. The key differences between MGN's opex proposal, which we have accepted, and our alternative estimate are that we have included:

- a more recent inflation forecast from the Reserve Bank of Australia (RBA)[4]
- higher base year opex, which is $6.5 million ($2022–23) more than MGN's proposal, largely because MGN incorrectly applied inflation when escalating into $2022–23 terms[5]
- a final year increment, which is $11.1 million ($2022–23) lower than MGN proposed, primarily due to:
  - updating forecast inflation through to June 2023
  - MGN incorrectly applying inflation when escalating into $2022–23 terms
  - MGN removing debt raising costs from base year opex of the six-months extension period twice[6]

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4 RBA, *Statement on Monetary Policy – Appendix: Forecast*, November 2022.

5 MGN, *2023–28 Access arrangement proposal – Information request 22*, 11 October 2022.

6 MGN, *2023–28 Access arrangement proposal – Information request 22,* 11 October 2022; MGN, *2023–28 Revisions to final plan – Attachment 8.1A – Opex Forecast Model*, September 2022.

- a higher price growth forecast, which is $2.8 million ($2022–23) more than MGN forecast because we have used a more recent labour price growth forecast and different input price weights
- our exclusion of two step changes proposed by MGN which related to cyber security ($3.6 million, $2022–23) and the renewable gas communication and customer education program ($3.0 million, $2022–23). This is because there is insufficient evidence to justify the additional expenditure as being prudent and efficient, and, in the case of the education program, strong stakeholder opposition.

We note that in our alternative estimate we have included corrections to what in our view are errors in the calculation of some of MGN's forecasts. These largely relate to converting all dollars into a $2022–23 basis. While this in some cases has increased forecast opex, we consider this is appropriate as it provides a total opex forecast that would be incurred by a prudent service provider acting efficiently to deliver pipeline services.

Given our draft decision is to accept MGN's total opex forecast, reflecting that our alternative estimate is not materially different from MGN's forecast, we do not require any revisions to be made to MGN's access arrangement opex proposal. In forming any revised proposal, MGN should consider all of the corrections, amendments and reasoning we have made in forming our alternative estimate.

6.2 MGN's proposal

MGN used a 'base-step-trend' approach to forecast opex for the 2023–28 period, consistent with our preferred approach.[7]

After its initial submission in July 2022, MGN submitted an addendum in September 2022, to reflect changes to estimates following release of the Victorian Government's *Gas Substitution Roadmap.* From an opex perspective this primarily impacted the trend forecasts including MGN's output and productivity growth forecasts.

MGN proposed a total opex forecast of $399.4 million ($2022–23).[8] This included:

- using reported opex in 2021 as the base for forecasting opex over the 2023–28 period (total forecast base opex $339.2 million ($2022–23))
- adjusting its total base forecast opex by:
  - adding in previously capitalised overheads that are proposed to be expensed going forward ($3.0 million, $2022–23)
  - adding opex to comply with new obligations for a full year associated with call-centre onshoring ($6.8 million, $2022–23)
  - removing unaccounted for gas (UAFG) and debt raising costs ($7.3 million, $2022–23), which it forecast separately as category specific forecasts.

7 MGN, *2023–28 Final plan*, July 2022, p. 75.

8 AER analysis; MGN, *2023–28 Revisions to Final plan – Attachment 8.1A – Opex Forecast Model*, September 2022; MGN, *2023–28 Final plan*, July 2022, pp. 70–89; MGN, *2023–28 Revisions to final plan*, September 2022, pp.18–21.

- adding an estimate of the difference between the base year opex and the opex it will incur in the final year of the current access arrangement period, increasing opex by $22.4 million ($2022–23).
- applying its overall rate of change forecast to its adjusted base opex, reducing opex by $5.9 million ($2022–23). This included:
  - input price growth increasing opex by $5.1 million ($2022–23)
  - output growth reducing opex by $11.0 million ($2022–23)
  - zero productivity growth.
- three step changes for a capex to opex transfer, new cyber security obligations and a renewable gas communication and community education program. This increased its opex forecast by $17.9 million ($2022–23)
- a category specific forecast for a priority service program (PSP) of $4.8 million ($2022–23)
- debt raising costs of $3.7 million ($2022–23).

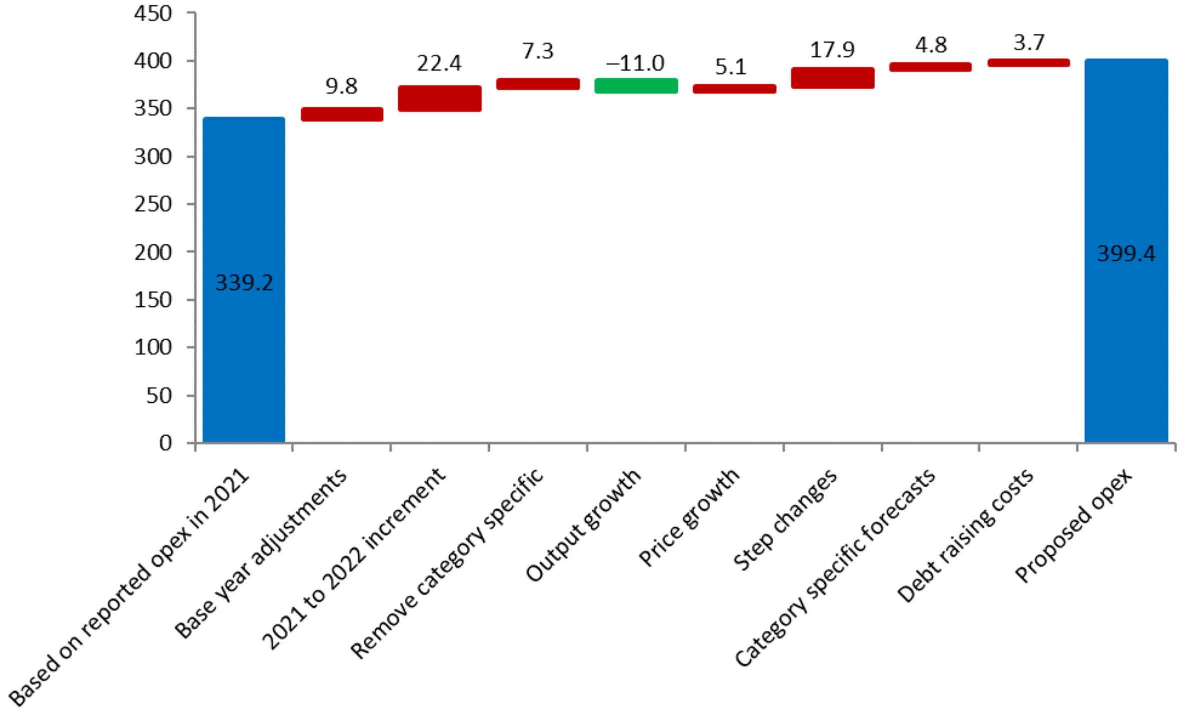
Table 6.2 MGN's proposed opex for the 2022–23 access arrangement period ($million, 2022–23)

	2023–24	2024–25	2025–26	2026–27	2027–28	Total
Total opex, excluding debt raising costs	81.1	80.2	79.3	77.6	77.4	**395.6**
Debt raising costs	0.7	0.7	0.8	0.8	0.8	**3.7**
Total opex, including debt raising costs	**81.8**	**80.9**	**80.0**	**78.4**	**78.2**	**399.4**

Source: AER analysis; *2023–28 Revisions to final plan – Attachment 8.1A – Opex Forecast Model*, September 2022.
Note: Numbers may not add up due to rounding.

We show in Figure 6.2 the different elements that make up MGN’s opex forecast.

Figure 6.2 MGN's proposed opex for the 2022–23 access arrangement period ($million, 2022–23)



Source: MGN, *2023–28 Revisions to final plan – Attachment 8.1A – Opex Forecast Model,* September 2022; AER analysis.
Note: Numbers may not add up to total due to rounding.

MGN’s total opex forecast of $399.4 million ($2022–23) is $47.2 million ($2022–23), or 10.6%, lower than the amount we determined in our 2018–22 decision for MGN[9] and $52.7 million ($2022–23), or 15.2%, higher than its actual and estimated opex over the 2018–22 access arrangement period.[10]

6.2.1 Stakeholder views

We received submissions raising opex issues from 16 stakeholders, including a joint community organisation submission made up of 8 stakeholders, and our Consumer Challenge Panel (CCP28).

We have taken these submissions into account in this draft decision and have summarised them in Table 6.3.

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9 AER, *Multinet Gas access arrangement 2018–22, PTRM – return on debt update for 2022*, September 2021.

10 MGN, *Regulatory accounts 2018 to 2021*; MGN, *2023–28 Revisions to final plan – Attachment 8.1A – Opex Forecast Model*, September 2022.

Table 6.3 Submissions on MGN's 2023–28 opex proposal

Stakeholder(s)	Issue	Description
Brotherhood of St Laurence (BSL), Joint Victorian Community Organisation (VCO) Submission, Energy Australia, BSL (TRAC Partners)	Total opex	BSL considered that due to stranding risk opex increases should be avoided or minimised. It also stated that the current MGN gas appliance rebates are not responsible expenditure and should be considered in relation to productivity and discretionary expenditure.[11] BSL does not consider that there is evidence of MGN passing on benefits from its merger (with AGN) to consumers.[12] TRAC Partners, on behalf of BSL, also stated that they were not certain the base year is efficient.[13] The Joint VCO submission considered that a high standard of evidence is required for any opex increases.[14] Energy Australia expressed concerns that MGN's spending in the current period was consistently below forecasts, possibly indicating gaming or a material forecasting error.[15]
Origin Energy, BSL (TRAC Partners)	Base adjustments	Origin Energy noted the relative ease of migrating costs between capex and opex and considered that cost allocation should be consistent with the cause of the costs and should only change in exceptional circumstances.[16] TRAC Partners, on behalf of BSL, expressed concerns about expensing items as opex. It considered it in the best interests of consumers for these costs to remain as capex.[17]
Energy Users Association of Australia (EUAA), BSL, Origin Energy	Rate of change / trend	The EUAA considered that the *Gas Substitution Roadmap* does not inhibit productivity improvements and that businesses are still incentivised to make productivity improvements.[18] BSL considered higher productivity targets should be applied, noting that the current offer of rebates indicate that businesses could be more efficient.[19] Origin Energy considered zero productivity growth reasonable considering the demand projections.[20] TRAC Partners, on behalf of BSL, did not consider zero productivity growth appropriate because, even if demand declines, costs are also likely to decrease somewhat, and there is still opportunity for technical change.[21]
CCP28, EUAA, BSL, Energy	Step changes – renewable	CCP28 expressed concerns about end consumer consultation on the program, noting a need to distinguish between willingness to pay and in

11 Brotherhood of St. Laurence, *2023–28 Access arrangement proposal submission*, September 2022, pp. 23–24. Note: Brotherhood of St. Laurence also provided a supporting document prepared on their behalf by TRAC Partners. This supporting document is only cited separately where it provides additional information from BSL's submission.

12 Brotherhood of St. Laurence, *2023–28 Access arrangement proposal submission,* September 2022, p. 26

13 TRAC Partners prepared on behalf of Brotherhood of St. Laurence, *2023–28 Access arrangement proposal submission,* September 2022 pp. 83–84.

14 Victorian community organisations, *2023–28 Access arrangement proposal submission*, September 2022, p. 2.

15 Energy Australia, *2023–28 Access arrangement proposal submission*, September 2022, p. 3.

16 Origin Energy, *2023–28 Access arrangement proposal submission*, September 2022, p. 3.

17 TRAC Partners prepared on behalf of Brotherhood of St. Laurence, *2023–28 Access arrangement proposal submission*, September 2022, pp. 83–84.

18 EUAA, *2023–28 Access arrangement proposal submission*, September 2022, p. 9.

19 Brotherhood of St. Laurence, *2023–28 Access arrangement proposal submission*, September 2022, p. 27.

20 Origin Energy, *2023–28 Access arrangement proposal submission*, September 2022, p. 3.

21 TRAC Partners prepared on behalf of Brotherhood of St. Laurence, *2023–28 Access arrangement proposal submission*, September 2022, p. 85.

Stakeholder(s)	Issue	Description
Australia, Joint VCO Submission, Friends of the Earth Melbourne, Darebin Climate Action Now	gas communication and customer education program	principle / values-based support. CCP28 stated that it appeared the businesses did not explore whether it should be business as usual expenditure, who should pay and who should be responsible for providing the service.[22] The EUAA did not support the program. It noted in principle support does not indicate willingness to pay and customers should not be incurring these costs.[23] BSL and the Joint VCO submission strongly opposed the proposed program, highlighting the importance of independent information and the absence of an equivalent fund for electrification.[24] Energy Australia, Friends of the Earth Melbourne and Darebin Climate Action Now also opposed the program.[25]
CCP28, EUAA, Energy Australia, BSL, Joint VCO Submission, Red Energy and Lumo Energy	Category specific forecasts – PSP	CCP28 expressed concerns about consumer consultation on the PSP, noting the need to distinguish between willingness to pay and in principle/values-based support, and that it appears businesses did not explore whether the costs should be business as usual expenditure, who should pay and who should be responsible for providing the service.[26] The EUAA appreciated the efforts in engagement for the PSP but questioned if it is a genuine step change, favouring base opex funding given zero productivity.[27] Energy Australia also considered the initiative admirable but thought that the businesses should fund the PSP internally as the expenditure is more discretionary in nature and thus inconsistent with the lowest cost of delivering pipeline services. It was also concerned the services provided under the PSP may be duplicative.[28] BSL and the Joint VCO submission appreciated the PSP initiative but opposed additional consumer funding and considered that there is not a demonstrated need for the step change. BSL also noted that some consumers stated their support was dependent on consultation with the community sector.[29] The Joint VCO submission also highlighted issues it had with self-identification for the register and considered that the views of some on the PSP advisory panel were misrepresented as support.[30] Red and Lumo also did not support additional funding for the PSP. They considered it reflects business as usual activities and offered limited additional value over retailer customer hardship programs. They were also concerned that they have not yet seen any benefits from the AGN(SA) PSP.[31]

22 CCP28, *2023–28 Access arrangement proposal submission*, September 2022, pp.18–20.

23 EUAA, *2023–28 Access arrangement proposal submission*, 30 September 2022, p. 9.

24 Brotherhood of St. Laurence, *2023–28 Access arrangement proposal submission*, September 2022, pp. 24–25; Victorian community organisations, *2023–28 Access arrangement proposal submission*, September 2022, p. 3.

25 Energy Australia, *2023–28 Access arrangement proposal submission*, September 2022, p. 2; Darebin Climate Action Now (DCAN), *2023–28 Access arrangement proposal submission*, 28 September 2022, p. 3; Friends of the Earth Melbourne, *2023–28 Access arrangement proposal submission*, September 2022, p. 2.

26 CCP28, *2023–28 Access arrangement proposal submission*, 30 September 2022, pp. 12–13, 18–20.

27 EUAA, *2023–28 Access arrangement proposal submission*, 30 September 2022, p. 9.

28 Energy Australia, *2023–28 Access arrangement proposal submission*, September 2022, p. 3.

29 Brotherhood of St. Laurence, *2023–28 Access arrangement proposal submission*, September 2022, p. 24.

30 Victorian community organisations, *2023–28 Access arrangement proposal submission*, September 2022, pp. 2–3.

31 Red Energy and Lumo Energy, *2023–28 Access arrangement proposal submission*, October 2022, pp. 3–4.

Stakeholder(s)	Issue	Description
CCP28, EUAA, Brotherhood of St Laurence (BSL)	Consumer engagement	CCP28 considered that the engagement was broad, genuine in intent and provided depth on some topics. However, CCP28 had concerns about how topics were raised, adequacy of the level of engagement, the methods used (such as the use of live polls), customer attrition, distinction of in-principle support versus willingness to pay and the absence of engagement with consumers since March 2022, noting economic and policy changes since. It felt that divergent views from stakeholders were insufficiently resolved on some issues, did not consider the supporting stakeholder KPMG report was genuinely independent and viewed the statistics presented in the customer engagement KPMG report as not a meaningful quantitative measures of consumer support.[32] The EUAA considered the combined network engagement process excellent.[33] BSL felt engagement was well coordinated and supported by useful information, but not all consumer advocate concerns were addressed, and they felt some of their views were misrepresented.[34]

6.3 Assessment approach

Our role is to decide whether or not to accept a business's forecast opex. We approve the business's forecast opex if we are satisfied that it meets the opex criteria. The opex criteria require that:

> Operating expenditure must be as such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services.[35]

In deciding whether forecast opex meets the opex criteria, we also apply the forecasting and estimate requirements under the National Gas Rules (NGR), which include that:

> A forecast or estimate must be arrived at on a reasonable basis and must represent the best forecast or estimate possible in the circumstances.[36]

We use a form of incentive-based regulation to assess the business's forecast opex over the access arrangement period at a total level. To do so, we develop an alternative estimate of total opex using a 'top-down' forecasting method, known as the 'base–step–trend' approach.[37]

Once we have developed our alternative estimate of total opex, we compare it with the business's total opex forecast to form a view on the reasonableness of the business's

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32 CCP28, *2023–28 Access arrangement proposal submission*, 30 September 2022, pp. 14–18.

33 EUAA, *2023–28 Access arrangement proposal submission*, 30 September 2022, p. 3.

34 Brotherhood of St. Laurence, *2023–28 Access arrangement proposal submission*, September 2022, pp. 5, 9–10.

35 NGR, r. 91(1). Rule 91(2) also provides that the forecast of required operating expenditure of a pipeline service that is included in the full access arrangement must be for expenditure that is allocated between reference services in accordance with Rule 93.

36 NGR, r. 74(2).

37 A 'top-down' approach forecasts total opex at an aggregate level, rather than forecasting all individual projects or categories to build a total opex forecast from the 'bottom up'.

proposal. If we are satisfied the business's total forecast meets the NGR requirements, we accept the forecast. If we are not satisfied, we substitute the business's forecast with our alternative estimate.

In making this decision, we consider the reasons for the difference between our alternative estimate and the business's forecast, and the materiality of that difference. We also take into consideration the interrelationships between the opex forecast and other constituent components of our decision, such that our decision is likely to contribute to the achievement of the National Gas Objective (NGO).[38]

6.3.1 Incentive regulation and the 'top-down' approach

Incentive regulation is designed to prevent network businesses from exploiting their natural monopoly position by setting prices in excess of efficient costs.[39] A key feature of the regulatory framework is that it is based on incentivising networks to be as efficient as possible. We apply incentive-based regulation across the energy networks we regulate, including gas networks. More specifically for opex, we rely on the efficiency incentives created by both ex-ante revenue regulation (where an opex allowance is granted over a multi-year regulatory period) and the efficiency carryover mechanism (ECM).[40]

The incentive-based regulatory framework partially overcomes the information asymmetries between the regulated businesses and us.[41] It is intended to align the commercial goals of the network businesses to the objectives of the regulatory regime—especially the long-term interests of consumers (the NGO).[42]

Incentive regulation aligns these goals by encouraging regulated businesses to reduce costs below our forecast, in order for them to make higher profits, and 'reveal' their costs in doing so. The information revealed by the businesses allows us to develop better expenditure forecasts over time. Revealed opex reflects any efficiency gains made by a business over time. As a network business becomes more efficient, this translates to lower forecasts of opex in future access arrangements, which means consumers also receive the benefits of the efficiency gains made by the business. Incentive regulation therefore aligns the business' commercial interests with consumer interests.

The Productivity Commission explains:

> Under incentive regulations, the regulator forecasts efficient aggregate costs over the upcoming regulatory period (of usually five years), which it uses to set a revenue allowance for that period. The business makes higher profits if it

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38 NGL, s. 28(1)(a); NGL, s. 23.

39 Productivity Commission, *Electricity Network Regulatory Frameworks, volume 1, No. 62*, 9 April 2013, p. 188.

40 The approach we apply to assessing a business' opex (and which we have applied in this decision) is more fully described in the Expenditure Forecast Assessment Guideline and its accompanying explanatory materials, which are published on the AER's website.

41 Productivity Commission, *Electricity Network Regulatory Frameworks, volume 1, No. 62*, 9 April 2013, p. 189.

42 The NGO is set out under the NGL, s. 23 which is: '...to promote efficient investment in, and efficient operation and use of, natural gas services for the long-term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas.'

> reduces costs below those forecast by the regulator. In doing so, the business reveals the efficient costs of delivering the service, which would then influence the regulator's determination in the next period. Accordingly, incentive regulation encourages efficiency while reducing the risks that networks use their monopoly positions to set unreasonably high prices.[43]

Incentive regulation is designed to leave the day-to-day decisions to the network businesses.[44] It allows the network businesses the flexibility to manage their assets and labour as they see fit to comply with the opex criteria[45] and achieve the NGO.[46]

Our general approach is to assess whether opex, in aggregate, is sufficient to satisfy the opex criteria over the access arrangement period, rather than to assess all individual opex projects or programs. As noted above, to do so, we develop an alternative estimate of total opex using the 'base–step–trend' forecasting approach (section 6.3.2). This is generally a 'top-down' approach, but there may be circumstances where we need to use 'bottom-up' analysis, particularly in relation to our base opex assessment and for step changes.

6.3.2 Building an alternative estimate of total forecast opex

As a comparison tool to assess a business's opex forecast, we develop an alternative estimate of the business' total opex requirements in the forecast period, using the base–step–trend forecasting approach. We apply the forecasts and estimate requirements under the NGR.[47]

If a business adopts a different forecasting approach to derive its opex forecast, we develop an alternative estimate and assess any differences with the business' forecast opex

Figure 6.3 summarises the base-step-trend forecasting approach:

43 Productivity Commission, *Electricity Network Regulatory Frameworks, volume 1, No. 62*, 9 April 2013, p. 27.

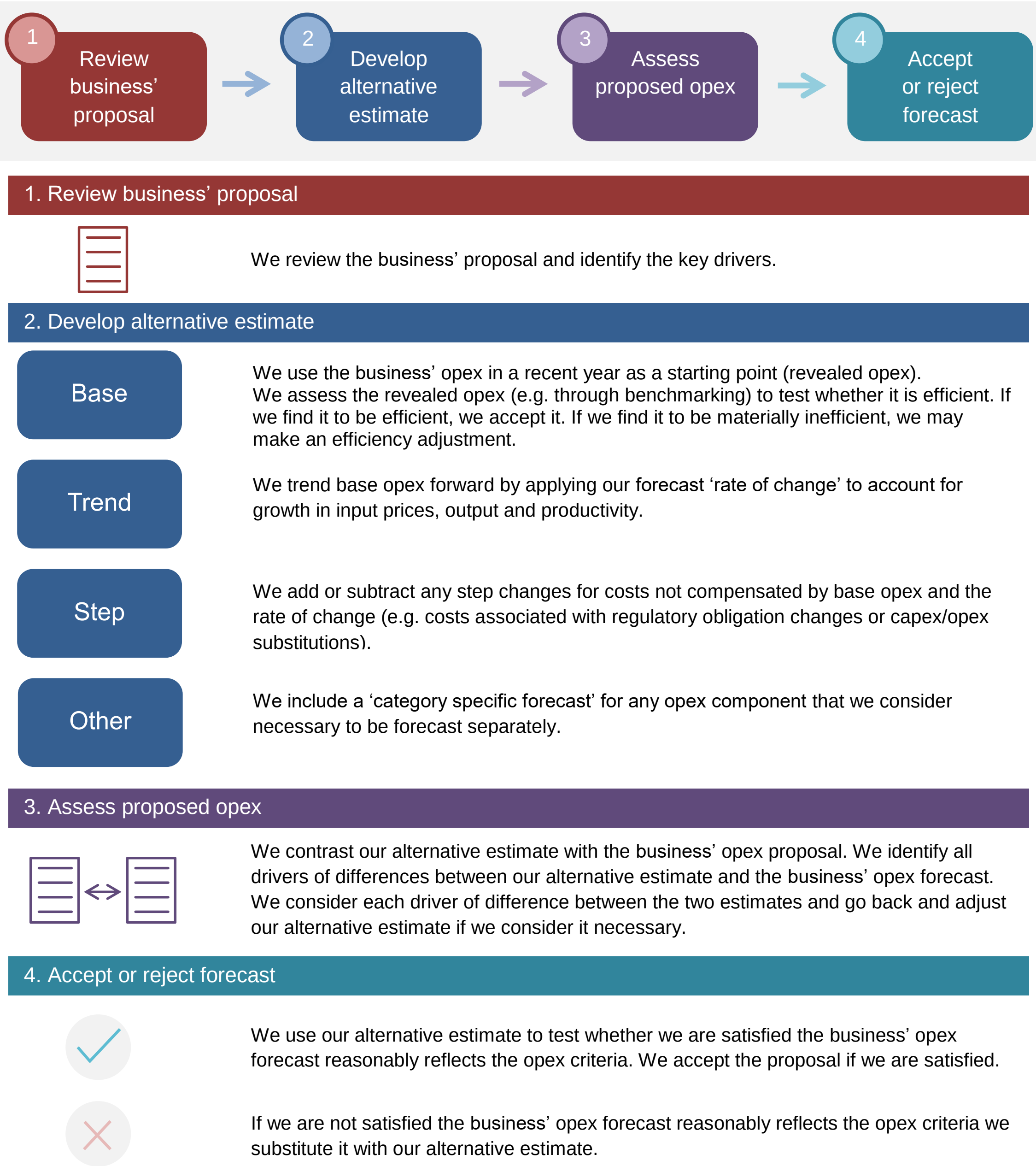
44 Productivity Commission, *Electricity Network Regulatory Frameworks, volume 1, No. 62*, 9 April 2013, pp. 27–28.

45 NGR, r. 91.

46 NGL, s. 28(1)(a); s. 23.

47 NGR, r. 74.

Figure 6.3 Our opex assessment approach



6.3.3 Interrelationships

In assessing MGN's total forecast opex, we also considered other components of the access arrangement proposal that could interrelate with our opex decision. The matters we considered in this regard included:

- the ECM carryover—the level of opex used as the starting point to forecast opex (the final year of the current access arrangement period, 2018–22) should be the same as the level of opex used to calculate ECM carryovers. This ensures that the business is rewarded (or penalised) for any efficiency gains (or losses) it makes in the final year the same as it would for gains or losses made in other years
- the operation of the ECM in the 2018–22 access arrangement period, which provides MGN an incentive to reduce opex in the base year

- our assessment of forecast demand growth, including MGN's forecast growth in customer numbers and mains length, which we used to forecast output growth
- the impact of cost drivers that affect both forecast opex and forecast capex, including forecast labour price growth
- our assessment of the rate of return, to ensure there is consistency between our determination of debt raising costs and the rate of return building block
- the outcomes of MGN's engagement with consumers and stakeholders in developing its proposal.

6.4 Reasons for draft decision

Our draft decision is to accept MGN's total opex forecast of $399.4 million ($2022–23), including debt raising costs, for the 2023–28 period.[48]

As detailed in Table 6.1, our alternative estimate of $391.8 million ($2022–23) is not materially different ($7.5 million, $2022–23, or 1.9% lower) from MGN's total opex forecast proposal. Therefore, we are satisfied that MGN's total opex forecast satisfies the opex criteria.[49] We are satisfied it was arrived at on a reasonable basis and represents the best forecast possible in the circumstances.[50]

The main drivers for the differences are set out in section 6.1 and we discuss the components of our alternative estimate, and our assessment of MGN's proposal, below. Full details of our alternative estimate are set out in our opex model, which is available on our website.

6.4.1 Base opex

This section provides our view on the prudent and efficient level of base opex that we consider MGN would need for the safe and reliable provision of services over the 2023–28 access arrangement period.

In its updated proposal, MGN used a base year of 2021 and base year opex of $67.8 million ($2022–23) or $339.2 million ($2022–23) over the five years of the next access arrangement period.[51]

In our alternative estimate, we also used 2021 as the base year but used a base year opex of $69.2 million ($2022–23) or $345.8 million ($2022–23) over 5 years to form our alternative estimate. Our higher alternative estimate is largely due to correcting an error in MGN's proposal related to applying inflation to convert amounts into a $2022–23 basis.[52]

MGN's opex in the first four years of the access arrangement period was significantly lower than allowed in our last determination. In particular, MGN's opex in 2021 was $21.3 million

48 MGN, *2023–28 Revisions to final plan – Attachment 8.1A – Opex Forecast Model*, September 2022.

49 NGR, r. 91.

50 NGR, r. 74.

51 MGN, *2023–28 Revisions to final plan – Attachment 8.1A – Opex Forecast Model*, September 2022.

52 MGN, *2023–28 Access arrangement proposal – Information request 22*, 11 October 2022.

(23.6%) lower than the forecast opex we approved in our last determination.[53] Opex in 2021 was also $0.8 million ($2022–23) or 1.2% lower than the opex for previous three years of the current period (2018–2020). MGN stated it has been able to reduce its internal costs after joining the Australian Gas Infrastructure Group (AGIG). It stated that it had also lowered its network operational and management services agreement contract costs due to consolidation. These savings have been partly offset by higher safety levies.[54]

We do not undertake our own economic benchmarking of gas distributors or category analysis review to assess the efficiency of base year opex. Instead, we rely on the economic benchmarking undertaken by the gas network businesses.

MGN's proposal referred to gas distribution benchmarking analysis (from the AGN (SA) revenue determination process) to support its view that its base year was efficient.[55] This was undertaken in 2020 by Economic Insights and MGN noted that it is the most recent industry benchmarking available. This analysis indicated that MGN's actual opex per customer was below average compared to the other gas distribution businesses over the 2015–19 period.[56] However, the results from the benchmarking which normalised the opex per customer measure found MGN's normalised results were typically above average.[57]

While not referred to in MGN's initial proposal, Economic Insights also undertook opex multilateral partial factor productivity benchmarking for AGN (SA) in 2020, including other gas distribution businesses. This showed that MGN was the least efficient business in terms of opex multilateral partial factor productivity benchmarking over the 1999–2019 period.[58]

Our assessment of the efficiency of opex in the base year has been informed by the benchmarking studies undertaken by Economic Insights in 2020. While these studies do not include updated data for 2020 or 2021, we consider that the results are indicative of the broader performance of MGN, including in the proposed base year. While the results from the benchmarking are mixed, we consider MGN's base opex likely to be efficient. This is due to the significant reductions in MGN's opex in the current access arrangement period, including in the base year, along with MGN's opex being subject to the incentives of the ECM over the 2018–22 period. Typically, where a service provider is subject to an ECM, we are satisfied that it does not have an incentive to increase its opex above efficient levels in the proposed base year.[59]

Energy Australia's submission expressed concerns about the reduction in MGN's opex in the current period and suggested we investigate as it may reflect a material forecasting error reflecting the gaming of carryover mechanisms.[60] As noted above, we have examined the lower actual opex over the period and consider this relates to the change of ownership and

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53 AER, *Multinet Gas access arrangement 2018–22, PTRM – return on debt update for 2022*, September 2021.

54 MGN, *2023–28 Access arrangement proposal – Information request 3*, 12 August 2022.

55 MGN, *2023–28 Final plan*, July 2022, p. 78.

56 MGN, *2023–28 Final plan*, July 2022, p. 78.

57 Economic Insights, *Benchmarking Operating and Capital Costs of Australian Gas Networks' South Australian Network Using Partial Productivity Indicators*, 15 June 2020, pp. 22–23.

58 Economic Insights, *The Productivity Performance of Australian Gas Networks' South Australian Gas Distribution System*, 15 June 2020, p. 27.

59 NGR, r. 71(1).

60 Energy Australia, *2023–28 Access arrangement proposal submission*, September 2022, p. 3.

systematic changes to costs which are likely to have resulted in lower and more efficient base opex.

6.4.1.1 Adjustments to base year opex

MGN proposed an adjustment to opex in the base year of $2.0 million ($2022–23) or $9.8 million ($2022–23) over the five years of the next access arrangement period.[61] Similarly, we adjusted opex in the base year by $2.0 million ($2022–23) (or $10.0 million ($2022–23) over the five years of the next access arrangement period) when we forecast our alternative estimate to reflect:

- expensing of certain previously capitalised overheads as a result of a change in capitalisation policy, which increased opex by $3.1 million ($2022–23) over the five years of the next access arrangement period
- the full year impact of new call centre onshoring obligations, which increased opex by $6.9 million ($2022–23) over the five years of the next access arrangement period.

The small difference between our total adjustment and that of MGN is primarily driven by the difference in actual and forecast CPI applied.

6.4.1.1.1 Capitalisation policy change

MGN proposed an increase in opex in the base year of $0.6 million ($2022–23), or a total adjustment of $3.0 million ($2022–23) over five years of the access arrangement period, to reflect the change in MGN's proposed capitalisation policy and increased expensing of overheads.[62] In our alternative estimate we have adjusted base year opex by $0.6 million ($2022–23) (or $3.1 million ($2022–23) over five years) to reflect the changes in MGN's capitalisation policy which we consider to be reasonable. The slight difference between our total adjustment and that of MGN is due to the difference in actual and forecast CPI applied.

MGN proposed to change how it classifies some overheads from capex to opex, in line with changes to its capitalisation policy.[63] In doing this, MGN will adopt the same approach to allocating these costs as AGN to align the cost allocation methodology (CAM) between the two businesses, following AGIG's acquisition of MGN in 2017. MGN submitted that the proposed treatment of overheads for the 2023–28 period would ensure alignment with current accounting standards, recognising that the nature of overheads has changed in recent years.[64]

Some stakeholders (Origin Energy and Brotherhood of St. Laurence) did not agree with the proposed expensing of overhead costs in their submissions. Origin Energy requested a more principled and consistent approach to cost allocation[65] and the Brotherhood of St. Laurence

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61 MGN, *2023–28 Revisions to final plan,* September 2022, p. 19.

62 MGN, *2023–28 Revisions to final plan,* September 2022, p. 19.

63 MGN, *2023–28 Final plan,* July 2022, pp. 75–76; MGN, *2023–28 Access arrangement proposal – Information request 19,* 13 September, pp. 1–3.

64 MGN, *2023–28 Access arrangement proposal – Information request 19*, 13 September, p. 2.

65 Origin Energy, *2023–28 Access arrangement proposal submission,* 30 September 2022, p. 3.

argued expensing overheads and other large capex items will increase tariffs in the near term and is not in the best interest of consumers in the current environment.[66]

We have reviewed MGN's proposed approach to forecast overheads and we are satisfied that it is reasonable. The expensed overheads are consistent with the new CAM, can be seen as opex in nature, and MGN has made the required offsetting changes to its capex forecast, which does not include any of the same overhead costs capitalised.

Under the National Electricity Rules (NER), network services providers must submit their proposed CAM to us for approval, and we must approve a proposed CAM that complies with the Cost Allocation Guidelines.[67] By contrast, the NGR do not contain a formal cost allocation framework for gas networks and do not require us to assess a change in MGN's cost allocation or capitalisation policy. In this case, MGN provided a copy of its current CAM along with justification for its proposed changes and we are satisfied that the reclassification is reasonable.

6.4.1.1.2 Call centre onshoring

MGN proposed an increase in opex in the base year of $1.4 million ($2022–23), or $6.8 million ($2022–23) over the next access arrangement period, to meet new obligations to onshore its customer call centre and back of house operations from the Philippines.[68] In our alternative estimate we have also made this adjustment to opex in the base year, but for $6.9 million ($2022–23) over the five years of the next access arrangement period. The difference between our total adjustment and that of MGN is driven by the difference in the actual and forecast CPI applied.

MGN stated in its proposal that in 2017 MGN was acquired by CK Infrastructure Holdings (CKI Group) and came together with Australian Gas Networks (AGN) and the Dampier Bunbury Pipeline to form the AGIG.[69] The Foreign Investment Review Board approved the acquisition, contingent on the conditions that all bulk customer data, bulk personal information, and data as to the quantum of gas delivered from sites relating to MGN must remain in Australia. MGN had been outsourcing its combined contact centre and back of house operations from a service provider based in the Philippines. MGN submitted an action plan to the Foreign Investment Review Board that it would continue its existing contract in the Philippines until the contract termination on 31 December 2021.

MGN considered several options to comply with the Foreign Investment Review Board requirements, including exercising a contract extension option with their current provider to establish a contact centre onshore, insourcing front of house and back office operations with MGN, transitioning MGN's front of house and back office operations to AGN, and establishing an onshore contract with a new provider.[70] Based on economic cost benefit

66 Brotherhood of St. Laurence, *2023–28 Access arrangement proposal submission,* 30 September 2022, p. 26.

67 NER, cl. 6.15.4.

68 MGN, *2023–28 Final plan,* July 2022, pp. 71, 76.

69 MGN, *2023–28 Final plan – Attachment 8.2 – Opex Business Cases*, July 2022, p. 3.

70 MGN, *2023–28 Final plan – Attachment 8.2 – Opex Business Cases*, July 2022, p. 3.

analysis, MGN chose to extend the contract with its current provider and bring the front of house and back office operations onshore.

MGN commenced this onshoring project in February 2021 with the recruitment and training of onshore agents taking place from June 2021 to September 2021.[71] During this period onshore agents commenced back-office services under the direct supervision from their Philippines based counterparts. Full transition to the onshoring of front of house and back-office services occurred in October 2021. As a result, MGN's base year opex does not include a full year of recurring onshore call centre costs and it has therefore included this base adjustment in its proposal.

We considered MGN's Commonwealth regulatory obligations for data control requirements under the Foreign Investment Review Board conditions, which we also considered in our draft decision for United Energy's electricity distribution proposal for onshoring costs.[72] We are satisfied that MGN is required to comply with these regulatory obligations for its data control requirements. Our internal technical review of the proposed costs associated with meeting these requires concluded the costs are reasonable and would be incurred by a prudent and efficient business. On this basis we have included the onshoring costs as a base adjustment in our alternative estimate.

6.4.1.2 Removal of category specific costs

In some circumstances a particular category of opex may be removed from the base year expenditure if it is more appropriate to forecast that category separately. We refer to these as 'category specific forecasts' (see section 6.4.4). We have removed unaccounted for gas (UAFG) and debt raising costs from base opex and forecast them separately. This is consistent with our standard approach and MGN's proposal.[73]

MGN added $7.3 million ($2022–23) to its base opex to account for category specific forecasts, which is $0.2 million ($2022–23) lower than the $7.5 million ($2022–23) increase we made in our alternative estimate.[74] The removal of category specific forecasts for MGN had the effect of increasing its reported opex in 2021 due to MGN's UAFG amount being less than the benchmark in the base year. The slight difference between MGN's proposed amount and our alternative estimate is due to our use of the more recent inflation figures when we escalated into $2022–23 terms.

6.4.1.3 Final year increment

Our standard approach to estimating final year opex is to add the difference between the approved forecast opex amounts in the base year (2021) and the final year of the current period to the reported opex in the base year.[75] To account for the six-month extension of the current access arrangement period, we have treated the six-month extension period (1 January–1 July 2023) as the final 'year'. We have annualised forecast opex for the

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71 MGN, *2023–28 Final plan – Attachment 8.2 – Opex Business Cases*, July 2022, p. 3.

72 AER, *Draft decision – United Energy determination 2021–26 – Attachment 6 Operating expenditure*, September 2020, pp.45–46.

73 MGN, *2023–28 Final plan,* July 2022, p. 76.

74 MGN, *2023–28 Revisions to final plan – Attachment 8.1A – Opex Forecast Model,* September 2022.

75 AER, *Expenditure forecast assessment guideline for electricity distribution*, August 2022, pp. 24–25.

extension period to account for its shorter length. This approach is consistent with MGN's proposal and our past decisions for the Victorian electricity distribution networks.

MGN proposed to include $22.4 million ($2022–23) for the estimate of 1 January–1 July 2023 opex, which is higher than the $11.4 million ($2022–23) in our alternative estimate.[76]

The variance between our alternative estimate and MGN's proposal is due to:

- our use of the latest inflation figures when we escalated base year opex into $2022–23
- correction of an error MGN made in its proposal when escalating its base opex for the six-month extension period, which applied a full year's inflation instead of only six months' worth of inflation.

6.4.2 Rate of change

Once we estimate opex in the final year of the 2018–23 period, we apply a forecast annual rate of change to forecast opex for the 2023–28 access arrangement period. We applied an overall annual average rate of change of –0.6% to derive our alternative estimate of opex. This is higher than MGN's forecast of –0.8%. We compare both forecasts in Table 6.4.

Table 6.4 Forecast annual rate of change in opex, %

	2023–24	2024–25	2025–26	2026–27	2027–28
MGN's proposal					
Price growth	0.4	0.5	0.6	0.3	0.3
Output growth	–0.7	–0.7	–1.2	–1.5	–1.9
Productivity growth	–	–	–	–	–
Rate of change	**–0.3**	**–0.1**	**–0.6**	**–1.2**	**–1.6**
AER alternative estimate					
Price growth	0.6	0.9	0.9	0.4	0.3
Output growth	–0.7	–0.7	–1.2	–1.5	–1.9
Productivity growth	–	–	–	–	–
Rate of change	**–0.1**	**0.3**	**–0.3**	**–1.1**	**–1.5**
Difference	**0.2**	**0.4**	**0.2**	**0.1**	**0.0**

Source MGN, *2023–28 Revisions to final plan – Attachment 8.1A – Opex Forecast Model*, September 2022.
Note: The rate of change = (1 + price growth) × (1 + output growth) × (1 − productivity growth) − 1. Numbers may not add up to totals due to rounding. Amounts of '0.0' and '–0.0' represent small non-zero values and '–' represents zero.

The difference between our forecast overall rate of change and MGN's is that we have used a different price growth forecast, which we discuss below.

6.4.2.1 Forecast price growth

MGN proposed average annual price growth of 0.4%, which increased its total opex forecast by $5.1 million ($2022–23). We have used real average annual price growth of 0.6% in our

76 MGN, *2023–28 Revisions to final plan – Attachment 8.1A – Opex Forecast Model,* September 2022.

alternative estimate of total opex. This increases our total opex alternative estimate by $7.9 million ($2022–23).

Both we and MGN forecast price growth as a weighted average of forecast labour price growth and non-labour price growth:

- Both we and MGN used an average of two wage price index (WPI) growth forecasts for the electricity, gas, water and waste services (utilities) industry in Victoria to forecast labour price growth. MGN used forecasts from its consultant, BIS Oxford Economics, and Deloitte Access Economics.[77] It sourced the Deloitte Access Economics forecasts from our final decisions for the Victorian electricity distributors for the 2021–26 regulatory control period. In our alternative estimate, we have replaced the Deloitte Access Economics forecasts with the more recent forecasts from our new consultant KPMG.[78]
- Both we and MGN applied a forecast non-labour real price growth rate of zero.
- We applied the weights of 62% and 38% to account for the proportion of opex that is labour and non-labour respectively. MGN used weights of 59.7% and 40.3%.

Consequently, the key difference between our real price growth forecasts, and MGN's, is that we have updated our labour price growth forecast to include the more recent forecasts from KPMG, instead of the older Deloitte Access Economics forecasts. We also used different input price weights but the impact of this is less significant.

We have updated our forecasts of WPI to reflect the latest available information

Our standard approach to forecasting labour price growth is to use an average of two WPI growth forecasts for the utilities industry in the relevant state. We use one set of forecasts provided by the network, and one set that we receive from our own consultant. For this determination we engaged KPMG to provide WPI growth forecasts for the Victorian utilities industry.

Consistent with this approach, MGN used forecasts from its consultant, BIS Oxford Economics, and Deloitte Access Economics. It sourced the Deloitte Access Economics forecasts from our final decisions for the Victorian electricity distributors for the 2021–26 regulatory control period.

Since MGN submitted its access arrangement proposal, we have received new WPI growth forecasts from KPMG, which reflect more up-to-date economic information. We used these newer forecasts in place of the Deloitte Access Economics forecasts that MGN used.

We show the labour price growth forecasts from BIS Shrapnel, KPMG and the average WPI growth rate in Table 6.5. We then added the legislated superannuation guarantee increases to forecast labour price growth. The last legislated superannuation guarantee increase is due to occur on 1 July 2025.[79] We do this because the WPI does not include superannuation and

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77 BIS Oxford Economics, *Input price escalation forecasts to 2027/28*, p. 4.

78 KPMG, *WPI forecast report*, September 2022, p. 41.

79 https://ato.gov.au/SuperRate

thus the WPI growth forecasts do not capture the increase in the price of labour when the superannuation guarantee increases.

Table 6.5 Forecast labour price growth, %

	2023–24	2024–25	2025–26	2026–27	2027–28
WPI growth — KPMG	0.6	1.1	0.8	0.4	0.4
WPI growth — BIS Oxford Economics	0.4	0.9	1.0	0.9	0.7
Average WPI growth	0.5	1.0	0.9	0.6	0.5
Superannuation guarantee increase	0.5	0.5	0.5	–	–
Forecast labour price growth	1.0	1.5	1.4	0.6	0.5

Source: BIS Oxford Economics, *Input price escalation forecasts to 2027/28*, p. 4; KPMG, *WPI forecast report*, September 2022, p. 41; AER analysis.

Note: Numbers may not add up to totals due to rounding. Amounts of '0.0' and '–0.0' represent small non-zero values and '–' represents zero.

Input price weights

We have used input price weights of 62% and 38% respectively for labour and non-labour. These are the weights ACIL Allen used in its econometric analysis of output and productivity growth.[80] We understand that these weights have been used consistently in the econometric analysis of gas distribution that both ACIL Allen and Economic Insights have done, and which has been submitted to the AER previously. It is important that the same input price weights are used to forecast price growth as are used in the econometric modelling for output and productivity growth forecasts. This ensures both inputs and output are consistently defined to forecast price growth, output growth and productivity growth.

MGN, however, applied input price weights of 59.7% and 40.3% for labour and non-labour respectively to forecast price growth.[81] It stated that the weights it used were based on 'the AER's benchmark weights'.[82] However, these are the input price weights we use for electricity distribution. We use different weights for electricity transmission. We do not have 'benchmark weights' for gas distribution because we do not do benchmarking of gas distributors and we do not publish an annual benchmarking report for gas. As a result, we have used the weights in the ACIL Allen 2022 report.

6.4.2.2 Forecast output growth

MGN proposed average annual output growth rate of –1.2% which reduced its proposed opex forecast by $11.0 million ($2022–22). We have also forecast average annual output growth of –1.2%.

For electricity distribution determinations, we typically forecast output growth based on the forecast growth in a defined output measure, based on econometric modelling. However, for

80 ACIL Allen, *Opex partial productivity study 2022*, June 2022, p. 11.

81 MGN, *2023–28 Final plan – Attachment 8.1 – Opex Forecast Model*, July 2022.
We note that these weights are slightly different to the weights (of 59.2% and 40.8%) that Multinet stated it used in its final plan.

82 MGN, *2023–28 Final plan*, July 2022, pp. 79–80.

gas distribution decisions, we have not undertaken the modelling needed to determine a standard industry output specification.

To assess MGN's output and productivity growth forecasts, we tested how the proposed output growth, net of productivity growth, compared to the output and productivity growth forecast using the output specifications derived from the available econometric studies. These econometric studies have been submitted in previous gas distribution determinations and were undertaken between 2015 and 2022.[83] We have taken the opex cost functions estimated by each of these studies and forecast output and productivity growth using the forecast growth in energy throughput, customer numbers, mains length and the regulated asset base. In this way we have produced output and productivity growth forecasts specific to MGN's circumstances. When we compared the results of the different studies we compared forecast output growth and productivity growth together because an output specification that leads to higher output growth often tends to also give higher forecast productivity growth.

We compared MGN's average annual output growth net of productivity growth of –1.2% against the outcomes of the available econometric studies as shown in Table 6.6. We found MGN's forecast (–1.2%) to be only slightly below the forecast based on ACIL Alen's 2022 report (–1.1%), which MGN submitted with its proposal.

The results of ACIL Allen's modelling are lower than all the other econometric models previously submitted to us. However, the other econometric studies were completed up to seven years ago and have not been updated for data published since they were completed. Given this, we have placed less reliance on these older econometric studies to inform our assessment.

Consequently, we are satisfied that MGN's forecast of output growth, net of productivity growth, has been arrived at on a reasonable basis and is the best forecast possible in the circumstances.[84]

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83 ACIL Allen, *Opex partial productivity analysis, Report to Australian Gas Networks Limited*, 20 December 2016; Economic Insights, *Relative opex efficiency and forecast opex productivity growth of Jemena Gas Networks*, February 2015; Economic Insights, *Gas distribution businesses opex cost function, Report prepared for Multinet Gas*, 22 August 2016; Economic Insights, *Relative efficiency and forecast productivity growth of Jemena Gas Networks (NSW)*, 24 April 2019; ACIL Allen, *Opex partial productivity study 2022*, 16 June 2022.

84 NGR, r. 74(2).

Table 6.6 Comparison of forecast output growth net of productivity growth

Model Specification	Output growth	Productivity growth	Output growth net of productivity growth
MGN's initial forecast	0.2	0.4	–0.2
MGN's updated forecast	**–1.2**	**–**	**–1.2**
ACIL Allen (2016)	–2.4	–2.9	0.5
Economic Insights (2015)	–2.9	–4.0	0.9
ACIL Allen (2016)	–2.3	–2.9	0.5
Economic Insights (2016)	–0.7	–1.0	0.3
Economic Insights (2019)	–1.1	–0.7	–0.4
ACIL Allen (2022)	**–1.8**	**–0.7**	**–1.1**

Source: MGN, *2023–28 Final plan – Attachment 8.1 – Opex Forecast Model*, July 2022; MGN, *2023–28 Revisions to final plan – Attachment 8.1A – Opex Forecast Model*, September 2022; AER analysis.
Note: Amounts of '0.0' and '–0.0' represent small non-zero values and '–' represents zero.

6.4.2.3 Forecast productivity growth

MGN forecast average productivity growth of zero in its updated proposal. We have also included forecast average productivity growth of zero in our alternative estimate.

MGN reduced its productivity growth forecast from 0.4% in its initial proposal to zero when it updated its proposal to account for the Victorian Government's *Gas Substitution Roadmap*.[85] The econometric analysis conducted by ACIL Allen in 2022, and submitted by MGN, found positive returns to scale. The econometric results also indicate a reduction in customer density will likely reduce productivity growth. MGN's updated proposal included both lower, negative, output growth and a reduction in customer density. Both factors should put downward pressure on productivity growth. Consequently, we agree that the *Gas Substitution Roadmap* is likely to reduce the productivity growth that can be achieved.

For the reasons outlined in section 6.4.2.2 above, we consider that MGN's forecast of output growth, net of productivity growth, represents the best forecast in the circumstances. Consequently, we have adopted MGN's productivity forecast of zero.

Stakeholder submissions

We received several submissions that addressed productivity growth. The Energy Users Association of Australia and the Brotherhood of St. Laurence considered the gas distributors should be able to achieve positive productivity growth forecasts.[86] Historically we have expected this for gas distributors, given econometric studies have consistently found positive technical change and positive returns to scale. However, the forecast of productivity growth should reflect the outlook facing the network, particularly forecast output growth and the forecast change in business conditions. In this case, the available econometric models suggest positive productivity growth will be hard to achieve (see Table 6.6). This is largely due to the loss of returns to scale due to the forecast decline in output. Further, the decline in

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85 MGN, *2023–28 Revisions to final plan*, September 2022, pp. 20–21.

86 EUAA, *2023–28 Access arrangement proposal submission*, September 2022, p. 9; Brotherhood of St. Laurence, *2023–28 Access arrangement proposal submission*, September 2022, p. 27.

customer density, which is a business condition in many of the econometric models, will put downward pressure on productivity growth.

Origin Energy considered zero productivity growth to be 'a reasonable approach given the networks are no longer expected to grow'. [87] Origin Energy's submission recognised that fewer returns to scale can be expected in a low growth environment. We have taken this into account and, when considered alongside MGN's forecast output growth, we are satisfied that a forecast of zero productivity growth is reasonable.

6.4.3 Step changes

In developing our alternative estimate, we include prudent and efficient step changes for cost drivers such as new regulatory obligations or efficient capex / opex trade-offs. As we explain in the *Expenditure forecast assessment* guideline for electricity, we will generally include a step change if the efficient base opex and the rate of change in opex of an efficient service provider do not already include the proposed cost for such items and they are required to meet the opex criteria.[88]

MGN's proposal included three step changes totalling $17.9 million ($2022–23), or 4.5% of its proposed total opex forecast.[89] We show these in Table 6.7 along with our alternative estimate, which is to include step changes totalling $11.2 million ($2022–23). Our lower alternative estimate reflects that we are not satisfied that all the proposed step changes are prudent and efficient.

Table 6.7 MGN proposal for step changes and our alternative estimate ($million, 2022–23)

Step change	MGN's proposal	AER alternative estimate	Difference to MGN proposal
Capex to opex reclassification	11.2	11.2	–
Cyber security	3.6	–	–3.6
Renewable gas communications and customer education program	3.0	–	–3.0
Total	**17.9**	**11.2**	**–6.6**

Source: AER analysis; MGN, 2023–28 Final plan – Attachment 8.1 – Opex Forecast Model, July 2022.
Note: Numbers may not add up to total due to rounding.

The following sections outline the reasons for our draft decision, including the alternative estimates we have developed.

6.4.3.1 Capex-opex reclassification of activities

MGN initially proposed a $11.6 million ($2022–23) step change for the reclassification of certain activities, previously classified as capex, to opex.[90] MGN subsequently revised this number to $11.2 million ($2022–23) when it submitted its updated proposal.[91] This included

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87 Origin Energy, *2023–28 Access arrangement proposal submission*, September 2022, p. 3.

88 AER, *Expenditure forecast assessment guideline for electricity distribution*, August 2022, p. 26.

89 MGN, *2023–28 Final plan,* July 2022, pp. 78–79.

90 MGN, *2023–28 Final plan,* July 2022, p. 71.

91 MGN, *2023–28 Revisions to final plan,* September 2022, p. 19.

correcting an error we identified in the application of the CPI in the capex model. We have included $11.2 million ($2022–23) in our alternative estimate for this proposed step change because we consider these costs are prudent and efficient.

Table 6.8 MGN's capex-opex reclassification step change ($million, 2022–23)

	2023–24	2024–25	2025–26	2026–27	2027–28	Total
MGN's proposal	3.3	2.7	2.1	1.1	2.1	11.2
AER alternative estimate	3.3	2.7	2.1	1.1	2.1	11.2
Difference	**–**	**–**	**–**	**–**	**–**	**–**

Source: MGN, 2023–28 *Revisions to final plan – Attachment 8.1A – Opex Forecast Model*, September 2022; AER analysis.

Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

MGN proposed that certain activities previously classified as capex were more consistent with an opex classification. As a result, it proposed a step change which increased its forecast opex by $11.2 million ($2022–23). It provided a report from accounting firm BDO to confirm that these costs meet the accounting standards and relevant criteria for opex classification.[92] MGN also provided detailed business cases for each program of costs to be expensed in the 2023–28 period, describing the need for the activity and including the options analysis it had undertaken with a cost breakdown for each option.

We have reviewed MGN's proposed reclassification of activities and we are satisfied that it is reasonable, and the costs are prudent and efficient. The activities proposed for reclassification (such as sampling or repair and maintenance type activities), are driven by safety and compliance obligations, occur every access arrangement period and do not extend the life of the assets. We are also satisfied that no project costs have been counted in both capex and opex, and that all costs moved to opex have been removed from forecast capex.

6.4.3.2 Cyber security

MGN proposed a step change of $3.6 million ($2022–23) to meet new legislative obligations under the *Security Legislation Amendment (Critical Infrastructure Protection) Act 2022*.[93] MGN considered it would need to achieve maturity indicator level 3 (MIL-3), security profile 3 (SP3), capabilities as set out in the Australian energy sector cyber security framework (AESCSF) to meet these obligations.[94] We have not included the proposed step change in our alternative estimate. We consider that MGN's proposal to achieve MIL-3, SP 3, capabilities is higher than the prudent and efficient investment required to meet the likely regulatory obligations of complying with security profile 1 (SP1) capabilities under *Security Legislation Amendment (Critical Infrastructure Protection) Act 2022*.

92 MGN, *2023–28 Final plan – Attachment 8.3 – BDO reclassification of certain programs to opex,* July 2022.

93 MGN, *2023–28 Final plan,* July 2022, p. 71.

94 MGN, *2023–28 Final plan – Attachment 9.19 – IT Business Cases*, July 2021. p. 70.

Table 6.9 MGN's Cyber Security step change ($2022–23)

	2023–24	2024–25	2025–26	2026–27	2027–28	Total
MGN's proposal	0.6	0.6	0.7	0.9	0.9	3.6
AER alternative estimate	–	–	–	–	–	–
Difference	**–0.6**	**–0.6**	**–0.7**	**–0.9**	**–0.9**	**–3.6**

Source: MGN, *2023–28 Revisions to final plan – Attachment 8.1A – Opex Forecast Model*, September 2022; AER analysis

Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

In terms of the legislative requirements for the security of critical infrastructure, we note that the original *Security of Critical Infrastructure Act 2018* has undergone several amendments. The first being the *Security Legislation Amendment (Critical infrastructure) Bill 2020,* which was divided into two separate parts. The first part became the *Security Legislation Amendment (Critical Infrastructure) Act 2021* in December 2021 and put in place the requirements for entities to report cyber security incidents, and the setting up of a regime for the Commonwealth to respond to serious cyber security incidents.[95] The second part became the *Security Legislation Amendment (Critical Infrastructure Protection) Act 2022* in April 2022, which requires responsible entities to have and comply with a critical infrastructure risk management program (RMP) and also imposes enhanced cyber security obligations that relate to Systems of National Significance.[96]

The regulatory obligation to have a RMP in place, under the *Security Legislation Amendment (Critical Infrastructure Protection) Act 2022,* has not yet been switched on by the relevant minister. This is likely to occur in December 2022. The Australian Government Department of Home Affairs has released draft *Security of Critical Infrastructure (Critical Infrastructure risk management program) Rules 2022*,[97] which specifies the matters it proposed to be contained in an RMP and requires responsible entities to meet principle-based outcomes.

The RMP requires responsible entities to identify, and as far as reasonably practicable, take steps to minimise or eliminate material risks that could have a relevant impact on the asset.[98] At present the proposed *Security of Critical Infrastructure (Critical Infrastructure risk management program) Rules 2022* contain obligations relating to protections within four key hazard vectors, being physical and natural, cyber and information security, personnel and supply chain functions.[99] In regard to the cyber and information security vector, a business's RMP must assess cyber security risks and in this regard the *Security of Critical Infrastructure (Critical Infrastructure risk management program) Rules 2022,* if passed, will require energy providers to meet obligations set out in the 2020–21 AESCSF Framework Core, and

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95 Australian Government, *Security Legislation Amendment (Critical Infrastructure) Act 2021*, December 2021.

96 Australian Government, *Security Legislation Amendment (Critical Infrastructure Protection) Act 2022*, Parts 4-6, April 2022.

97 Australian Government, *Security of Critical Infrastructure (Critical infrastructure risk management program) Rules (LIN 22/018) 2022*, Exposure draft.

98 Australian Government, *CISC Factsheet – Risk Management Program,* August 2022, p. 1.

99 Australian Government, *CISC Factsheet – Risk Management Program,* August 2022, p. 2.

specifically requiring the entity to meet SP1. These draft rules are currently undergoing consultation with industry and stakeholders.

We asked MGN to identify the specific regulatory obligation in *the Security Legislation Amendment (Critical Infrastructure Protection) Act 2022* or any other legislative requirement which required compliance with MIL-3, SP3. MGN stated that the *Security Legislation Amendment (Critical Infrastructure Protection) Act 2022* requires it (as a responsible entity for certain critical infrastructure assets) to comply with risk management program obligations once the *Security of Critical Infrastructure (Critical Infrastructure risk management program) Rules 2022* are 'turned on' by the relevant minister. MGN expected, based on its current view of the rules, that a maturity level of SP1 will be required within 18 months of the rules being turned on, which will require MGN to achieve MIL-3 compliance in some areas of the AESCSF.[100]

MGN engaged Ernst & Young and with its assistance developed the AGIG Cyber Security 5 Year Roadmap.[101] The program was designed to uplift AGIG's cyber risk management capabilities to MIL-3 standard (as defined in the AESCSF) over the period 2021–25, including for MGN. The 5 Year Roadmap outlined MGN's step change scope of works for its cyber security domain activities to achieve MIL-3 compliance. We consider some of these security domains achieving MIL-3 compliance to be in excess of the requirements, to meet the compliance obligations of SP1, as defined in the AESCSF.[102]

Our technical advisory group considered that while the AESCSF requirements are currently not compulsory standards, given the *Security Legislation Amendment (Critical Infrastructure) Act 2022*, the AESCSF requirements should be considered good industry practice. We also understand the risk management plan requirements are likely to be switched on in December 2022.[103] When the risk management requirements are switched on it is likely that MGN as a gas distribution business will be required to comply with the rule requirements to reach the capabilities of a maturity level of SP1 against the AESCSF.

The Energy Users Association of Australia supported the concept of a step change for cyber security.[104] It and the Brotherhood of St Laurence commented that it is important that the AER assesses whether the amount is prudent and efficient.[105]

We consider that currently there is no new regulatory obligation for MGN to achieve the capabilities of SP3 of the AESCSF as indicated in its proposal. We also consider that as a result, MGN's proposed expenditure, which is based on MIL-3, SP3 requirements, is higher than the likely efficient expenditure required to meet the regulatory obligations of the RMP when it is switched on (SP1, consistent with the draft rules and the information presented by

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100 MGN, 20*23–28 Access arrangement proposal – Information request 18,* 26 September 2022.

101 MGN, *2023–28 Final Plan – Attachment 9.19 – IT Business Cases,* July 2021, p. 70.

102 Australian Government, *Australian Energy Sector Cyber Security Framework – 2022 AESCSF Framework Core,* 19 April 2022.

103 Australian Government, *Department of Home Affairs – Risk Management Program – Formal Consultation – Town Hall*, October 2022.

104 EUAA, *2023–28 Access arrangement proposal submission*, September 2022, p. 9.

105 TRAC Partners prepared on behalf of Brotherhood of St. Laurence, *2023–28 Access arrangement proposal submission*, September 2022, p. 65.

the Department of Home Affairs consultation on the risk management program). As a result we have not included this step change in our alternative estimate.

6.4.3.3 Renewable gas communication and customer education program

MGN proposed a $3.0 million step ($2022–23) change for a renewable gas communications and customer education program (the program).[106] We have not included this step change in our alternative estimate.

Table 6.10 MGN's Renewable gas communication and customer education step change ($2022–23)

	2023–24	2024–25	2025–26	2026–27	2027–28	Total
MGN's proposal	0.6	0.6	0.6	0.6	0.6	3.0
AER alternative estimate	–	–	–	–	–	–
Difference	**–0.6**	**–0.6**	**–0.6**	**–0.6**	**–0.6**	**–3.0**

Source: MGN, *2023–28 Final plan – Attachment 8.2 – Opex Business Cases*, July 2022, p. 20; AER analysis.
Note: Numbers may not add up to totals due to rounding. Values of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

MGN originally presented this step change in its draft plan at a cost of $7.4 million ($2022-23).[107] However, in response to stakeholder feedback on the draft plan, MGN stated the $4.4 million ($2022–23) marketing component would be funded through MGN's existing opex (now $4.5 million, $2022–23). The customer funded portion of the program, which was included in MGN's proposal, consists of $1.2 million ($2022–23) for expanded community engagement and $1.8 million ($2022–23) for school education, proposed due to customer interest expressed during consultation workshops.[108]

The proposed purpose of the program is to increase customer's awareness of MGN's renewable gas plans and provide customers with information to assist with choices they are making now around energy connections and appliances. MGN proposed this step change based on:

- low customer awareness and strong interest in receiving further information on renewable gas and in emissions reduction [109]
- managing reputational and customer risks associated with customer satisfaction, and information availability and financial risks associated with reductions in demand and new connections[110]
- customer support for the program based on in-workshop polls where 76% of respondents to an in-workshop poll strongly supported, and 17% somewhat supported, the program[111]

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106 MGN, *2023–28 Final plan,* July 2022, p. 71.

107 MGN, *2023–28 Draft plan*, January 2022, p. 72.

108 MGN, *2023–28 Final plan – Attachment 8.2 – Opex Business Cases,* July 2022, pp.33–34.

109 MGN, *2023–28 Final plan – Attachment 8.2 – Opex Business Cases,* July 2022, pp.18–21.

110 MGN, *2023–28 Final plan – Attachment 8.2 – Opex Business Cases,* July 2022, pp. 36.

111 MGN, *2023–28 Final plan – Attachment 5.3 – KPMG Final Report – MGN Customer Engagement Program,* July 2022, p.36.

Many stakeholders strongly opposed renewable gas communications from gas distribution businesses and additional funding for the program. Stakeholders were concerned about additional expenditure particularly at a time where there may be network decline, uncertainty as to the viability of hydrogen in networks, and the need for independent information on the future of energy.[112] CCP28, while considering the MGN's engagement to be genuine, raised concerns about what it saw as limitations of the consultation and assessment of customer support, including participant attrition, use of live polls and an apparent absence of a discussion about who should pay.[113]

We have reviewed the materials provided by MGN in supporting the proposed communications and education program, including via additional information requests to clarify specific issues, and we have not included this step change in our alternative estimate. In coming to this decision, we have considered that:

- The program expenditure is not driven by a new regulatory requirement, capex-opex trade off or a necessary response to an external change, but rather a level of customer support for these more discretionary actions.[114] In this regard we recognise the genuine effort and processes undertaken to engage with customers in relation to the program to test their support or otherwise for it, noting that the modest number of diverse, but not representative, customers directly consulted supported, or somewhat supported, the program at a cost of $2.00 annual cost per customer. However, we also consider that there were aspects of the customer consultation and assessment that could have been improved to inform this assessment:
- Despite the support MGN found when engaging with customers directly, there was strong stakeholder opposition to the step change and the associated additional costs. This remained the case even after MGN responded to the feedback it received in relation to its draft plan proposal and removed the marketing costs from the step change.
- Community engagement can be useful to enable customers to engage directly but could also be comparable to marketing in this context. This is particularly the case where there is significant uncertainty, possible further policy changes and changing demands. In addition, at $1.2 million over the 2023–28 access arrangement period, the costs can likely be paid for within business-as-usual expenditure.
- MGN has not in our view provided sufficient evidence that the customer funded community and education components of the step change are an efficient way to meet the objectives of the program (ensuring that customers are informed, involved and engaged in the energy transition as it relates to gas and are provided with the information they need to inform the choices they are making). In particular, we consider insufficient evidence has been provided that shows that school education is an efficient

112 EUAA, *2023–28 Access arrangement proposal submission*, September 2022, p. 9; Brotherhood of St. Laurence, *2023–28 Access arrangement proposal submission*, September 2022, pp. 24–25; Victorian community organisations, *2023–28 Access arrangement proposal submission*, September 2022, p. 3; Energy Australia, *2023–28 Access arrangement proposal submission*, September 2022, p. 2; Darebin Climate Action Now (DCAN), *2023–28 Access arrangement proposal submission*, September 2022, p. 3; Friends of the Earth Melbourne, *2023–28 Access arrangement proposal submission*, September 2022 p. 2.

113 CCP28, *2023–28 Access arrangement proposal submission*, September 2022, pp. 5, 17–20.

114 AER, *Better Resets Handbook – Towards Consumer Centric Network Proposals*, December 2021, pp. 27–28.

means of meeting the program's objectives of providing customers with awareness and practical information they need now. MGN noted that customers wanted this service, and that children can influence their families on sustainability matters and in some product categories. However, it is unclear to us whether it is efficient to use children/students to distribute information to current customers, and whether it is prudent to provide this information to children/students now as future customers, given the current levels of uncertainty, and that choice to use gas is largely limited to homeowners

- In addition, there is currently uncertainty as to the viability of renewable gas in material volumes in the Victorian gas distribution network, to the future of Victorian government policy around gas substitution and appliance replacement requirements. This uncertainty has been highlighted by MGN as presenting an asset stranding risk and which it proposed to reduce via accelerated depreciation.[115] While the future of gas may become clearer within the access arrangement period, we consider that it may be difficult for MGN to meet the program's objectives of offering customers with certainty and practical information about their energy and appliance choices now.
- Further, our view is that it remains open to MGN to use its base opex to communicate to customers, including the $4.5 million in opex funding that MGN noted would be used for marketing purposes, following stakeholder feedback.

6.4.4 Category specific forecasts

MGN's proposal included three expenditure items, or category specific forecasts, which it did not forecast using the base-step-trend approach. These were for debt raising costs, UAFG and the PSP. We have also included category specific forecasts for debt raising costs, UAFG and the PSP in our alternative estimate of total opex.

6.4.4.1 Debt raising costs

MGN proposed a category specific forecast for debt raising costs of $3.7 million in its proposal. We have included debt raising costs of $4.0 million ($2022–23) in our alternative estimate. This is $0.3 million ($2022–23) higher than the $3.7 million forecast ($2022–23) proposed by MGN.[116]

Debt raising costs are transaction costs a service provider incurs each time it raises or refinances debt. Our preferred approach is to forecast debt raising costs based on a benchmarking approach rather than a service provider's actual costs for consistency with the forecast of the cost of debt in the rate of return building block.

We used our standard approach to forecast debt raising costs, which is discussed further in Attachment 3 to the draft decision.

6.4.4.2 Unaccounted for gas

Consistent with MGN's proposal and our past decisions, we have included a category specific forecast of zero dollars in our alternative estimate for any UAFG penalties or rewards MGN receives. Consistent with this, we also propose to exclude UAFG costs from the ECM.

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115 MGN, *2023–28 Final plan*, July 2022, pp. 56–64.

116 MGN, *2023–28 Revisions to final plan – Attachment 8.1A – Opex Forecast Model*, September 2022; AER analysis.

UAFG refers to the difference between the quantity of gas delivered into and out of the distribution system. UAFG may be attributable to gas leakage or inaccurate gas measurement. The Essential Services Commission of Victoria sets a UAFG 'benchmark' within which MGN is expected to operate.[117] To provide an incentive for MGN to minimise gas losses, it incurs a penalty if UAFG exceeds the benchmark and receives a reward if it falls under the benchmark. To preserve this incentive, the business itself should incur the penalty or keep the reward, not consumers. As a result, we include a zero forecast for UAFG in our alternative estimate.

6.4.4.3 Priority service program

MGN proposed $4.8 million ($2022–23) of additional funding for a PSP to support customers experiencing vulnerability. The program includes:

- dedicated staff to design, manage and deliver the program
- development of a 'priority services register'
- improved communications for culturally and linguistically diverse (CALD) customers
- gas safety checks, emergency repairs and outage support.[118]

For the purpose of this draft decision we have included the PSP costs as proposed in our alternative estimate as a category specific forecast. However, we encourage MGN in preparing its revised proposal, to continue to work with customers and relevant stakeholders to potentially refine and revise the scope of the program, test customer support and demonstrate an efficient use of resources.

MGN proposed the PSP as a category specific forecast, consistent with the final decision for the vulnerable customer assistance program (VCAP) in AGN (SA)'s 2021–26 access arrangement. In AGN (SA)'s final decision, we stated that customer supported initiatives should be classified as a category specific forecast instead of a step change. This ensures the funding is spent as intended, requires businesses to report expenditure and allows us to remove the expenditure from the ECM.[119] It is also consistent with the *Better Resets Handbook*, which states that category specific forecasts should be limited to cost categories that have been included as category specific costs in previous AER decisions.[120]

MGN proposed the additional expenditure for this program on the basis:[121]

- that there is a role for networks to support customers experiencing vulnerability, highlighted by the Energy Charter, the AER Draft *Consumer Vulnerability Strategy* and associated Consumer Policy Research Centre research and the Financial Services Royal Commission
- of consistency with good industry practice, social license to operate, and the National Gas Objective in that it is in the long-term interest of customers

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117 MGN, *2023–28 Final plan,* July 2022, p. 76.

118 MGN, *2023–28 Revisions to final plan,* September 2022, p. 19.

119 AER, Final Decision, *Australian Gas Networks (SA) Access Arrangement, 2021–26 – Attachment 6 – Operating expenditure*, April 2021, p .23.

120 AER, *Better Resets Handbook – Towards Consumer Centric Network Proposals*, December 2021, p. 29.

121 MGN, *2023–28 Final plan – Attachment 8.2 – Opex Business Cases*, July 2022, pp. 39–42

- that it facilitates risk management – reducing MGN's risks around reputation, customer experience and occupational health and safety from moderate to low
- customer support – 93% of customers that responded to an in-workshop poll and considered dedicated support for vulnerable customers important or very important in the context of a $1.50 annual cost per customer.[122]

Other stakeholders appreciated the initiative but did not support additional funding for the PSP.[123] The Joint VCO submission raised concerns about the use of a register becoming a barrier for participation.[124] TRAC Partners, on behalf of The Brotherhood of St Laurence also raised concerns about the efficiency of network-specific programs given similar programs are also proposed by the other Victorian gas networks.[125] CCP28, while considering MGN's engagement to be genuine, raised concerns about what it saw as limitations in the consultation and assessment of customer support, including participant attrition, use of live polls and apparent absence of discussion about who should pay.[126]

We have reviewed the materials provided by MGN to support its PSP, including information provided in response to additional information requests. For the purpose of the draft decision, we have included the PSP costs as proposed in our alternative estimate. This is an on-balance decision and reflects that while this proposed step up in costs is not driven by a new obligation or capex/opex trade off:

- the PSP is similar to the VCAP program approved for AGN SA, and we consider the activities proposed result in a material increase in services, including:[127]
  - a dedicated customer service lead and manager to deliver the program and improve the customer experience for customers experiencing vulnerability
  - a priority services register resulting in a more responsive customer environment
  - gas safety appliance checks and emergency appliance repairs improving the safety and reliability of vulnerable customers gas appliances and gas use.
- we recognise the genuine effort and processes undertaken to engage with customers in relation to the PSP to test their support or otherwise for it, noting:
  - the modest number of diverse, but not representative customers directly consulted were of the view that it was important or very important to support vulnerable customers in the context of a $1.50 annual cost per customer, and

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122 MGN, *2023–28 Access arrangement proposal – Information request 17,* 27 September 2022, p. 2.

123 EUAA, *2023–28 Access arrangement proposal submission*, September 2022, p. 9; Brotherhood of St. Laurence, *2023–28 Access arrangement proposal submission*, September 2022, p. 26; Victorian community organisations, *2023–28 Access arrangement proposal submission*, September 2022, pp. 2–3; Energy Australia, *2023–28 Access arrangement proposal submission*, September 2022, p. 3; Red Energy and Lumo Energy, *2023–28 Access arrangement proposal submission*, October 2022, pp. 3–4.

124 Victorian community organisations, *2023–28 Access arrangement proposal submission*, September 2022, p. 2.

125 TRAC Partners prepared on behalf of Brotherhood of St. Laurence, *2023–28 Access arrangement proposal submission*, September 2022, p. 64.

126 CCP28, *2023–28 Access arrangement proposal submission*, September 2022, pp. 5, 17–20.

127 AER, Final Decision, *Australian Gas Networks (SA) Access Arrangement 2021–26 – Attachment 6 Operating expenditure*, April 2021, pp.22–25; MGN, *2023–28 Final plan – Attachment 8.2 – Opex Business Cases*, July 2022 pp. 40–41.

  - the effort to engage relevant stakeholders via the PSP Advisory Panel, which, while not supportive of additional costs, appreciated the initiative
- MGN's efforts to research and minimise duplication of services, align with other networks for consistency and consult with relevant stakeholders to develop the program, and commitment to ongoing consultation with these groups, as well as government agencies and other parts of the energy supply chain[128]
- in the *Towards Energy Equity* Strategy,[129] we recognised the need to deliver better outcomes for customers experiencing vulnerability and avoid exacerbating harm, which is a core objective of this program.[130]

Further, we consider that the proposed costs do not appear to be inefficient, with cost estimates for each activity proposed being provided and reflecting costs for similar activities undertaken elsewhere in MGN's business or externally and/or being based on market-based quotes.

While recognising the genuine effort by MGN to engage and consult, as raised by some stakeholders we acknowledge that the customer and stakeholder consultation and assessment of support could have been improved. This includes more clearly establishing and explaining the degree of need for these programs, and for them to be customer funded, and more widely and robustly testing customer and stakeholder willingness to pay for additional programs and addressing and / or reconciling any differences of view in terms of willingness to pay. We also encourage further consideration of the sample size and representation / mix of customers consulted.

In this regard, we encourage MGN, in preparing its revised proposal, to continue to work with customers and relevant stakeholders to potentially refine and revise the scope of the program, test customer support and demonstrate an efficient use of resources as reasonable for the scale of the program. This could include reviewing and refining the services proposed in consideration of stakeholder feedback, particularly concerns around issues with the register being a barrier to participation, which may also benefit from experience and learnings in other sectors such as financial services. We also encourage MGN to consider how the program's costs are best funded, further exploring whether there are efficiencies that can be achieved via collaboration, or review, and addressing other specific stakeholder comments on the program particularly where there are differing views between customers and stakeholders. As noted by CCP28, this is particularly pertinent given economic and policy changes that have occurred since the customer workshops ended in March 2022, including increased energy prices, high inflation, and the release of the Victorian Government's *Gas Substitution Roadmap*.

We also note that category specific funding ensures the program will be reviewed and/or discontinued should customers' needs or preferences change in the future. This includes if the program fails to meet expectations or is replaced by other programs. In this regard there may also be more efficient alternatives in the future, noting the AER is exploring the potential

128 MGN, *2023–28 Final plan – Attachment 8.2 – Opex Business Cases*, July 2022, p. 36.

129 AER, *Towards Energy Equity – a strategy for an inclusive energy market*, October 2022, p. 5.

130 MGN, *2023–28 Final plan – Attachment 8.2 – Opex Business Cases*, July 2022, p. 75.

for centralised assistance for customers experiencing vulnerability through its *Towards Energy Equity* strategy.[131]

[131] AER, *Towards Energy Equity – a strategy for an inclusive energy market – supporting document*, October 2022 pp.50-61.

Glossary

Term	Definition
ABS	Australian Bureau of Statistics
AER	Australian Energy Regulator
AESCSF	Australian Energy Sector Cyber Security Framework
AGIG	Australian Gas Infrastructure Group
AGN	Australian Gas Networks (Victoria and Albury)
AGN(SA)	Australian Gas Networks (South Australia)
CALD	Culturally and linguistically diverse
CAM	Cost allocation methodology
Capex	Capital expenditure
CCP28	Consumer Challenge Panel 28
CPI	Cost price index
ECM	Efficiency carryover mechanism
MIL-3	Maturity Indicator Level 3
MGN	Multinet Gas Networks
NER	National Electricity Rules
NGO	National Gas Objective
NGR	National Gas Rules
Opex	Operating expenditure
PSP	Priority service program
RBA	Reserve Bank of Australia
RMP	Risk management program
SP3	Security Profile 3
UAFG	Unaccounted for gas
VCAP	Vulnerable customer assistance program
WPI	Wage price index