Australian Gas Infrastructure Group
L6, 400 King William Street
Adelaide, SA 5000 Australia
PO Box 6468, Halifax Street,
SA 5000 Australia
+61 8 8227 1500
info@agig.com.au
agig.com.au

21 December 2023

Kate Symons
Chairperson
Essential Services Commission
Level 8, 570 Burke Street
Melbourne, Victoria 3000

Reviewing the Gas Distribution System Code of Practice

Dear Ms Symons,

We welcome the opportunity to respond to the Essential Services Commission's (the Commission) Draft Decision on the review into the Gas Distribution System Code of Practice (the Code).

The Australian Gas Infrastructure Group (AGIG) is one of Australia's largest energy infrastructure groups with distribution, transmission and storage assets worth over $9 billion. We deliver natural gas reliably, safely and efficiently to over 2 million residential, commercial and industrial customers across Australia, with 1.4 million of them in Victoria served by Multinet Gas Networks and Australian Gas Networks.

We are committed to decarbonisation and leading the transition from natural gas to renewable gases such as hydrogen and biomethane. We are investing in renewable gas projects – today we have three projects operating or under construction, and a pipeline of several projects at earlier stages which will provide confidence in the deliverability of renewable gas to customers.

We have significant concerns with the Draft Decision, particularly the proposal to require upfront connection charges for new gas connections. We believe it is based on several misunderstandings, factual errors and omissions and is in conflict with the Commission's objectives, particularly the objective to promote consistent regulatory treatment across the electricity and gas industries.

Two broad arguments support our view and are elaborated in our responses to the consultation questions:

1. The Draft Decision misunderstands and includes factual errors regarding the operation and outcomes of the current Economic Feasibility Test (EFT). The EFT is designed to produce efficient outcomes and is effectively the same test that applies to electricity connection charges in Victoria and gas connection charges in other states. When properly understood, we consider it is clear the current approach will continue to deliver

appropriate outcomes for all energy customers as the Victorian economy decarbonises and no change is required; and

2. We consider various costs and consequences resulting from the proposed upfront charges have been omitted from the analysis, including:
   - A likely increase to gas distribution prices, not a decrease as implied in the Draft Decision. In circumstances up to now a new connection lowers tariffs for all customers as demonstrated in modelling which forms the basis of our tariffs approved by the Australian Energy Regulator (AER).
   - Furthermore, to the extent the introduction of the upfront charge will dissuade new connections, the outcome will be to increase prices for existing gas customers.
   - Blanket application of upfront charges will introduce cross subsidies, not remove them. This will occur as new customers, who have already paid for their own connection costs through the upfront charge, will also be paying for existing customers' connection assets through the network tariffs we charge. To avoid this, we will need to duplicate the current schedule network tariffs with a lower rate.
   - Retrospective application of the Code to parts of the network where the EFT has already been applied and the impact on in line developments means additional costs and increased asset stranding risks. Each of these issues will add to the costs of operating gas distribution networks if the Draft Decision is maintained in the Final Decision.

We consider that the concerns outlined above and in more detail in the attached submission result in the Draft Decision being in conflict with several objectives and matters the Commission must have regard to in achieving those objectives. These include the objective in the *Gas Industry Act* "to promote a consistent regulatory approach between the gas industry and the electricity industry" (section 18), where the proposal to require an upfront charge and the removal of the EFT would make the treatment of new connections for electricity and gas inconsistent. The proposed approach in the Draft Decision departs from this objective and does not provide any arguments as to why such a departure would be more efficient or practical.

Once again, we welcome the opportunity to respond to the Draft Decision. We strongly urge the Commission to reconsider its Draft Decision with regard to connection charges, having regard to all of its objectives. Properly recognising how the current Code and EFT operate in practice, and appropriately recognising the costs of upfront charges should lead the Commission to a different conclusion.

Should you wish to discuss our response please contact Peter Bucki, Head of Regulation [redacted].

Yours sincerely,

[redacted]

Roxanne Smith
Executive General Manager Corporate and Regulation

Attachment A – responses to the Questions for Stakeholders

1. Do you agree with the proposed introduction of upfront charges for new gas connections?

We do not support the proposal to introduce upfront charges for new gas connections for several reasons:

- The Draft Decision is based on analysis that misunderstands the application and outcomes of the Economic Feasibility Test (EFT) in the current Code (schedule 2) – the current approach to connection charges based on the EFT is designed to ensure the outcomes are efficient and, as explained below, there is no cross-subsidy as described between existing and new customers;
- The proposed introduction of upfront charges would in fact result in several inefficiencies and potential higher prices that outweigh any benefits from their introduction;
- The proposed introduction of upfront charges would also result in several unintended consequences, such as increased asset stranding risk;
- The proposed upfront charges are not consistent with the objectives of the Commission as set out in the *Gas Industry Act 2001 (Vic)* ("GI Act", section 18) and the *Essential Services Commission Act 2001 (Vic)* ("ESC Act", sections 8 and 8A).

1.1: The Current Code and Operation of the Economic Feasibility Test

The Draft Decision and reasoning presented misunderstands the EFT in the current Code. Two key arguments are presented in the Draft Decision: that the current Code inefficiently incentivises new connections; and that the current Code results in cross-subsidisation by the existing customer base of new connections. We do not consider either of these points to be factually correct.

Schedule 2 of the Code provides guidance "with respect to the determination of the charge component of the terms and conditions" for a connection (sch 2 s 1). For tariff V customers the Code notes the connection charge "shall be the greater of the deficit from application of the economic feasibility test or zero" (sch 2 s 2(a)). The economic feasibility test is defined by the following equation (sch 2 s 3):

"Deficit = PV (Cost) – PV (Revenue)

where PV refers to a present value".

The application of the EFT and Schedule 2 overall means that a connection charge can only be zero if the present value of expected revenue from that specific connection is greater than the present value of the cost of installation.

At this point it is important to note that effectively the same test is applied to electricity connection charges in Victoria[1] and to gas connection charges in other states.[2] We return to this issue in section 1.3 below, but briefly note now that the Commission's objectives include promoting " a consistent regulatory approach between the gas industry and the electricity industry" (ESC Act s18(a)) and "consistency in regulation between States and on a national basis" (GI Act s8A(1)(f)).

In Victoria and other states, the framework applied in both electricity and gas is the same conceptually, in that connections can only proceed if they are efficient. For the gas networks, that outcome is ensured through recovery of connection charges over time through the revenue expected from the specific customer connecting to the network.

To date our own experience in modelling and delivering new connections shows consistently that new connections result in lower costs for all customers on the gas network. Where a new connections does not result in lower costs for all customers, a customer contribution is required. Because application of the EFT results in revenue at least equivalent, or greater than, the incremental costs of the new connection, a new Tariff V connection does not result in systemic cross-subsidisation.

Using the EFT to date a new connection lowers tariffs for all customers as demonstrated in modelling which forms the basis of our tariffs approved by the Australian Energy Regulator (AER), and therefore does not result in an upfront customer contribution in most cases for residential connections.

The inverse is also true. Taking the AER's recent Final Decision for AGN Victoria and Albury for the 2023/24 to 2027/28 period, if we were to remove all growth capital expenditure (i.e. expenditure for new developments) and associated demand and customer connections, this would lead to a 2% increase to distribution charges. To the extent the introduction of the upfront charge will dissuade connection, the outcome will be to increase prices for existing gas customers.

The current operation of the EFT is flexible enough to deal with any potential future declines in average consumption or customer connections without the proposed requirement for upfront charges. If fewer customers connect and the new connections use less gas, the outcome of the EFT will be to determine that a contribution from the new connection is required.

However, the outcome of the EFT does not represent any inefficiency or cross-subsidisation, whether it results in a customer contribution (like in electricity) or

[1] For electricity connections see sections 2.1.1 and 5.1 referring to capital contributions https://www.aer.gov.au/system/files/AER%20-%20Connection%20charge%20guidelines%20for%20electricity%20customers%20-%20April%202023.pdf

[2] See National Gas Rules, rule 119M(1).

does not (as has been the case for gas). It merely reflects whether the revenue expected from a customer exceeds the cost of the connection.

It would be useful for the Commission to share its analysis and modelling demonstrating how the introduction of blanket upfront charges would result in lower charges for existing customers.

1.2 Unforeseen outcomes of upfront charges

In addition to the points made above, we have concerns that the proposed upfront connection charges will in fact produce several unforeseen outcomes.

Tariff implications

The proposal as outlined in the Draft Decision would create a cross subsidy, not remove one as claimed by the Commission, as new customers would be contributing to the connection costs of existing customers. Current haulage tariffs allow for the cost of all connections to be recovered over time through haulage revenue from each connection (not a cross-subsidy as outlined above as haulage tariffs decrease with each new connection because of the application of the EFT).

Under current haulage tariffs and the proposed changes to the Code, new customers would pay upfront for their connection and pay a share of existing connection costs through haulage tariffs. New customers would thus pay for both new and existing connections.

To avoid this situation, distribution networks would need to provide different tariffs to new connecting customers. This would require detailed modelling of the new environment and subsequent approval by the AER – it would likely require a reopening of Access Arrangements. In doing so, distribution networks may need to develop tariffs for new customers that:

- avoid this cross subsidy created by the proposed connection charge; and
- give these new customers the benefit of having paid for their own connection cost up-front.

However, distribution networks do not charge customers directly as this function falls to retailers. If the proposed new connection charge was to proceed, oversight and active monitoring of retailers and the process they follow when assigning customers to the correct distribution tariff would be required by the Commission, in order to protect those new customers from the cross subsidy created.

Asymmetric application

The Draft Decision proposes that the upfront connection charge for affected new customers should include the direct costs of any new connection and any system augmentation costs required to support the new customer. However, it is not the case that new customers only increase system costs. As shown in the growth capital expenditure modelling outcomes above in section 1.1 (used to approve tariffs by the AER), the increased volumes of new connections can and do, in practice, lower costs for existing customers, providing a benefit to the system as a whole. Where this outcome is not the case, the EFT would require an upfront connection charge.

This point is particularly important, because many of the affected new connections are in infill areas which will not require planning approval. Because distribution network mains already exist in these areas, these new connections tend to lower average costs for existing customers as a whole, and in turn lower tariffs for existing customers.

The Draft Decision seems to suggest that by requiring upfront connection charges, tariffs for existing customers will result in distribution networks seeking a negative pass-through i.e. lower price. However, it is important to note that a positive pass-through (i.e. increase in price) could also eventuate. Any up-front connection fee would need to allow for this possibility, which would likely differ from customer to customer.

Logical inconsistency

The Commission, on page 5 of its discussion paper, states that:

> *In the transition to electrification, there is a risk that new customers might switch to all-electric systems before gas distributors are able to fully recover the costs associated.*

As noted above, since any development requiring new planning approval is in any case unable to get a gas connection, the proposed change to introduce an up-front cost is restricted to residential infill customers and some commercial customers. In the context of the latter, the Commission notes (p32):

> *New customers would be required to pay the full costs of a connection upfront. This impact is expected to be more significant for commercial customers as they are not captured by the planning ban and some may have more difficulty in finding all-electric appliances with those new connections to the network.*

Commercial customers, a major part of the customers affected by this proposed new connection charge are, as the Commission points out, least likely to leave the gas network, and therefore least likely to switch before we are able to recover unrecovered connection costs.

Further, a new residential build that connects to the gas network is unlikely to leave the network before their connection cost has been recovered.

Asset stranding

It is also important to address the concerns raised in the Draft Decision about asset stranding.

It is true that through an upfront charge, connection assets would not make their way into the RAB as the connection asset is funded fully upfront.

However, asset stranding risks are complicated. For example, where a new customer has a lower marginal cost of connection than the existing average cost of connection (as would likely be the case for residential connections that are connecting to an already existing network), including that connection in the RAB actually lowers our risk of asset stranding, even in cases where demand is declining (this is clearly demonstrated in our recent Access Arrangement that formed the basis of our current tariffs approved by the AER).[3]

The Commission should provide its detailed modelling which shows why it believes that its proposed approach will have the reduction in asset stranding it suggests, as this is contrary to the evidence accepted by the AER.

Impact on existing inline developments

There are also specific implications of the Draft Decision for gas infrastructure installed in new land developments, which investment decisions were made under the existing Gas System Distribution Code of Practice i.e. the current EFT.

The Draft Decision, if maintained, would fundamentally alter the EFT that was applied to justify the investment needed to support these new connections, as well as fundamentally altering the business case for developers who have already made their investments, including the need to augment the electricity network to accommodate energy load that was planned to be gas but is now electricity

An increased portion of the as yet unbuilt homes would likely no longer choose to connect if they suddenly faced with a connection fee which did not exist when the development was planned. The assets in question are already part of our Regulated Asset Base (RAB), and, to the extent that connections do not materialise, existing customers will therefore bear the costs of recovery of those investments through increased prices.

To prevent this from happening, if the Commission does implement an upfront connection charge, it should only do so for new developments, which have not yet commenced, grandfathering developments that have already started.

[3] Attachment 6.1 - Future of Gas: Our approach to accelerated depreciation, July 2022, pp19-20, available here

1.3 The Commission's Powers and Objectives

In coming to its final decision on amendments to the Code, we believe the Commission needs to carefully consider its objectives. Given the impact of the proposed changes outlined above, the Draft Decision would appear to be in conflict with several objectives and matters the Commission must have regard to in achieving those objectives.

Consistency with Electricity Regulation and Equal Treatment

Firstly, the GI Act section 18 expressly states that one of the objectives of the Commission is:

> "to the extent that it is efficient and practicable to do so, to promote a consistent regulatory approach between the gas industry and the electricity industry".

As outlined above, the guidance and EFT applied to new connections in schedule 2 of the current code is consistent with the regulatory treatment applied to electricity connections. The proposed approach in the Draft Decision departs from this principle and does not provide any arguments as to why such a departure would be more efficient or practical. As outlined above, the proposed approach would introduce several inefficiencies.

The intent of section 18 of the GI Act appears to be to ensure equal treatment of electricity and gas as alternative and competing sources of energy. As renewable and other net-zero emission gases are added to the regulatory framework and delivered via pipelines and networks, this principle remains important.

As section 18 is one of the Commission's objectives it must be taken into account as a factor in the Commission's decision making.

Gas consumers

The Commission's objective is "to promote the long-term interests of Victorian consumers" (ESC Act section 8(1)). In respect of gas distribution networks, consumers are taken to be "gas" consumers.[4] Subsection 2 further states that "the Commission must in seeking to achieve the objective specified in subsection (1) have regard to the price, quality and reliability of essential services."

In the Draft Decision the Commission seems to have focussed not on the long term interests of Victorian gas consumers with respect to price, quality and reliability but instead has had regard for a narrow view of achieving emission

[4] "Gas" is defined in the GI Act as "any gaseous fuel but does not include any gaseous fuel that is declared under section 8 not to be a gas for the purposes of this Act or any provision of this Act". The Draft Decision makes reference on several occasions to "fossil gas" which is undefined and not given specific reference in any of the Commission's powers which are applied to the broadly defined term "gas".

reduction through electrification of potential gas load. It is worthwhile noting the significant proportion of Victorian electricity produced from brown coal coupled with the slow roll out of renewable electricity in Victoria means that gas remains a relatively low emission energy source by comparison.

It is again important to highlight that gas distribution networks can deliver renewable gases and achieve net-zero emissions within the timeframes required by Victoria's emissions reduction targets. Here, our submission is not making an argument against environmental or emissions reduction objectives. It is merely noting that the Commission's primary objective does not refer to these objectives, but refers to "price, quality and reliability".

In making its decision the Commission appears to be favouring one specific technical solution to achieve decarbonisation over another, rather than focussing on the price, quality and reliability outcomes that are best for gas customers. We note that the proposed decision is likely to increase prices for Victorian gas customers and does nothing to improve quality or reliability of gas supply.

Whether electrification is a more efficient pathway to achieving net-zero emissions than renewable gases remains to be seen and is subject to different views.

However, the current connections framework, which refers to "gas" would allow customers to fairly choose between electrification and renewable gases on equal terms, and to choose natural gas as a transition fuel – within the bounds set within the planning framework and other elements of Victorian law. These choices are and will be reflective of efficient investments made by service providers consistently with the EFT in the Code, and the NGL and NGR as approved by the AER taking into account long term demand.

1a Are there any implementation costs, advantages or disadvantages to the options considered that we should take into account?

Our response to Question 1 details many of the disadvantages of the option chosen in the Draft Decision. The response to this question should be read in conjunction with the response to Question 1.

It is worth drawing out here the challenges associated with changing existing distribution tariffs to account for upfront payment by new connecting customers. This will require a reopening of Access Arrangements, and significant changes to existing tariff structures. This will require a significant investment of time by networks, regulators, and customer groups, all for a diminishing, marginal, number of new connections.

For all the options outlined, but particularly Option 2, there would be significant administration costs associated with the change. In particular, IT systems changes to address upfront charges are likely to be material.

We also note the potential increased customer complaints and bad debt issues as customers (in some cases with homes already designed or even partly constructed with a gas connection) react to the imposition of the upfront charge. This will increase costs for customers as a whole. Again, these issues need to be balanced against the relatively small number of connections in question.

As outlined above, the Commission's role is not to choose between alternative options for achieving net-zero emissions. Nonetheless, it is worth noting that the argument that discouraging new connections will decrease emissions is incorrect. Even allowing for the improved efficiency of heat pumps, switching from natural gas to electrification will result in higher carbon emissions for years to come so long as Victoria's electricity grid continues to rely on brown coal[5].

We would also like to note that the Commission has not presented it's detailed modelling to demonstrate the costs and benefits of its preferred approach. The outcomes presented in Table 5 of the Draft Decision differ significantly from those in our models presented and approved by the AER. It would be beneficial if the Commission could publish its modelling to show how the results were derived;

As a final point on upfront connections charges, many of the Commission's conclusions appear to be based on evidence, which has not been included. It is vital that the Commission in making conclusions share its information and modelling, particularly where the results will need to be replicated in distributor's own models to achieve the outcomes predicted for customers.

The Commission suggests (p28) that the benefits of its change outweigh the costs, but no formal cost-benefit analysis has been provided, nor has any regulatory impact statement, which we would have expected with this change. In particular, the two benefits listed on p28 are either wrong (the case of decarbonisation, see above) or incompletely assessed in the case of asset stranding (see above).

There is a qualitative summary of the Commissions conclusions in Table 4, but this is not the same thing as providing stakeholders with the results of a formal cost-benefit analysis. This is particularly important here because the affected customers, given the new residential connection ban and current practice in respect of industrial customers, are likely very small in number, so the absolute size of the net benefit, if it does exist at all, is important.

2. Should the proposed code be more specific about how distributors calculate the costs of a new connection, as an upfront charge to customers? If so, how?

[5] See The Role of Gas Infrastructure in Australia's Energy Transition p10 https://www.agig.com.au/gas-infrastructure-crucial-to-australia-energy-transition. As of December 2023 67% of energy delivered in Victoria over the previous 12 months was supplied by brown coal. Source – NEM Data Dashboard.

As outlined above there are several problems, inaccuracies and misunderstandings in the Draft Decision which lead to the decision to propose upfront connection charges. Further, specifying how distributors calculate connection costs would only add further complexity.

Connections are pipeline services regulated by the AER as part of each Access Arrangement and we anticipate that the approach adopted by distribution networks would be subject to AER approval. This process already determines the efficiency of costs (including for example for abolishments) and does not need to be duplicated in the code.

Giving distribution networks broad flexibility to determine how the actual costs of a connection are recovered will achieve the objectives of the commission, while ensuring efficiency and customer interests.

3. Do you agree with the proposed implementation of new connection charges to begin from 1 January 2025? Please discuss.

Notwithstanding the comments made above in response to questions 1 and 2, commencing the upfront charges from 1 January 2025 will be extremely challenging. A final decision on the code will not be available until some point in 2024, leaving less than a whole year to undertake a range of activities including:

- Developing and implementing IT systems and business procedures;
- Varying interactions and systems between retailers and distributors to implement the change;
- Assessing the need for variations to existing Access Arrangements, and developing and putting forward variation proposals to the AER (including changes to demand forecasts, service proposals, tariff structures, operating and capital expenditure on IT systems, and other issues); and
- Proceeding through the AER decision making process including stakeholder consultation, draft decisions, responses and final decisions.

We anticipate such a process would require at least 24 months, after a final decision on the Code is known, to complete.

4. Do you agree with the proposed definitions and processes for disconnection and abolishment? Please discuss.

Customer requests for abolishment

In terms of processes for abolishment, we have concerns with the newly introduced requirement that "a distributor must abolish a connection…where a customer requests the distributor to do so" (sections 6.2.1(b) and 6.2.3 of the draft code).

In most circumstances a property owner wanting to abolish their connection can and should contact their retailer. Retailers have existing relationships with customers and relevant details to verify ownership and billing arrangements. Conversely, distributors have limited direct connection to customers, including no contact or billing details which are held by retailers.[6] Changing this would require investment in IT and operational systems - including to confirm ownership – none of which are business as usual practices for distributors.

Direct customer to distributor requests would also represent a significant departure from current practice, where customers are required to contact their retailer to initiate changes to their connection (be that a disconnection or other issue). This risks further confusing interactions among customers, retailers and service providers and would like lead to significant customer concerns.

We understand that customer requested abolishments might be thought to be necessary in situations where the owner of an untenanted rental property might wish to abolish their connection but have no retailer as they are not a retail customer.

However, there are issues with this remedying situation by allowing customers to contact distributors directly. Firstly, the definition of "customer" in the code would not appear to include a property owner in these circumstances. A customers is:

> "a person to whom a distributor delivers gas through its distribution system at a distribution delivery point or a person who has sought connection to the distribution system for such delivery or potential delivery of gas".

Secondly, we understand a default retailer applies to each location. A property owner could establish a relationship with this retailer to initiate the abolishment process. As outlined above for general abolishments, retailers have systems for maintaining customer records and establishing ownership.

On balance we suggest the current approach, where retailers manage customer service requests be maintained for abolishments, under the same conditions as for a disconnection.

Finally, we with regards to abolishments, we note that it is important to address the issue raised in the consultation paper about distributor initiated abolishments. The safe and efficient operation of the network may depend on abolishing unused connections, or requiring abolishment of connections that have been disconnected but where the customer's intent is clearly to remain permanently disconnected. As the number of abolishments increases, these issues will become more important to address and we strongly encourage the Commission to work collaboratively with all stakeholders to develop an efficient and safe approach.

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[6] Distributors have on various occasions requested expenditure allowances for customer relationship management systems, and have consistently been denied this expenditure on the grounds that retailers hold this information and the relationship with customers.

Confirmation of ownership issues (disconnection)

Regarding a direction from a retailer for the distributor to disconnect a customer, we think further clarity is warranted. The Draft Code, 6.1.2 states:

> "the distributor must not disconnect the customer unless the retailer provides confirmation in writing that it is entitled to disconnect the customer under the Act, the Energy Retail Code of Practice, or the applicable contract with the customer."

We are concerned the insertion of "confirmation in writing" places the onus inappropriately on the distributor to ensure receipt of such confirmation, while also adding additional steps in the process and costs to customers. In practice, the onus must be on the retailer to ensure it is entitled to direct the distributor to disconnect a customer.

We suggest the drafting be changed to note that "when a retailer directs a distributor to disconnect a customer, the distributor may assume that the retailer is entitled to do so under the Act, the Energy Retail Code of Practice, or the applicable contract with the customer."

5. Do you agree with the proposed new provision of information obligations for gas distributors? Please discuss.

With regards to UAFG data reporting, we note that given reporting is required on or before 31 December following the end of that financial year, data is likely to be unsettled UAFG data. Settlement can take much longer than the reporting lag provided and is subject to change.

In response to several stakeholder submissions, it is important to note that UAFG is not solely comprised of fugitive emissions to atmosphere but also includes other elements includes metering inaccuracies and theft of gas.

6. Do you agree with our proposed amendments to remove duplication with other regulatory instruments and to streamline the code? Please discuss.

On enabling renewable gases and heating values, the Draft Decision is consistent with the Victoria Government's renewable gases paper and will allow renewable gases such as biomethane/hydrogen to be injected into the system, removing regulatory barriers.

Given the shift to zonal heating values we support the intention to remove heating values from the code.

7. **Do you agree with the removal of the overlap of metering requirements between our code and the National Gas Rules? Should we retain the requirements in clause 7 on meter accreditation, certification and testing? Please discuss.**

As a general principle, we are agree that where possible duplication of metering obligations between the Code and Part 19 of the NGR should be removed from the Code, unless it is required for reasons of clarity or market operation.

A detailed review of Part 19 and the Code would be required to ensure only the duplicated sections are removed (if they are to be removed) as there are parts of the Code that are not covered by Part 19 eg basic metering obligations do not appear in Part 19 of the NGR.

We also believe there is significant potential to improve any remaining metering requirements in the Code, to enable new technology (new meter types not envisaged when the Code was drafted), recognition of overseas testing and certification, and competition in certifying and calibrating equipment which is current written into the Code. Some elements of the Code as currently drafted inhibit options for purchasing and using meters that are built/calibrated/tested to international meter standards.

We suggest that the Commission host a forum with distributors/operators to further elaborate on these issues.

8. **Do you have any feedback on our proposed compliance and performance reporting requirements? Please discuss.**

No comment.

9. **Do you have any feedback on our proposed variations to gas distribution licences? Please discuss.**

No comment.

10. **Can you identify any other changes to codes of practice, guidelines, licences or other instruments we may need to make as a consequence of the proposed Gas Distribution Code of Practice?**

No comment.

11. Are there any issues with implementing the proposed Gas Distribution Code of Practice that we should consider?

For the code as a whole, we are concerned about the timeframes to implement several new obligations. Aside from concerns raised above about the introduction of upfront charges and the timing thereof, the new Code itself will into into force in May 2024. Several changes will require new IT systems, resources and procedures. Distributors may be left with only months or weeks to comply. We suggest transition arrangements, of at least 6 months, are needed for all new compliance obligations including new information requirements, and disconnection and abolishment processes.

12. Do you have other comments, feedback or suggestions about our draft decision or the proposed new code?

We have several drafting suggestions for consideration.

Clause 4.2.1

Notwithstanding our comments above in response to Question 1, we note clause 4.2.1 notes "the connection charge…must be determined in accordance with the approach set out in <u>clauses 2 to 5 of the Schedule 2 Guidance</u>" (underline added).

This appears to be a reference to the current code. Schedule 2 Guidance on connection charges would assumedly no longer apply under the proposed change. Schedule 2 in the Draft Code does not include these issues.

Notification of "AEMO as required"

Several clauses (5.6.1, 5.6.2, 5.7.1, 5.7.2, 6.1.4) note distributors must notify "affected parties (including AEMO as required)" but do not specify when notification of AEMO when notification of AEMO is required. This is vague and likely to cause confusion.

If these references to AEMO refer to notification obligations in other legislative instruments or market rules, they are redundant here and should be removed. If, however they are referring to particular requirements of the Commission to notify AEMO these should be specified more clearly.