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What is a reasonable price?

Response to gas market consultation paper

RBB Economics, 13 February 2023

1 Overview

In December 2022, the Treasury and the Department of Climate Change, Energy, the Environment, and Water (referred to just as "**Treasury**" in this submission) released a Consultation Paper ("**CP**") setting out the following two policy measures aimed at enabling domestic users to access adequate supply of gas at reasonable prices:

- First, an emergency temporary cap on wholesale gas prices for 12 months.
- Second, a mandatory code of conduct to guide behaviour including a "reasonable pricing provision" ("**RPP**") to ensure that domestic prices are set at reasonable levels.

Treasury has proposed that these interventions will be enforced by the Australian Competition and Consumer Commission (ACCC) using existing tools, including significant civil penalties under the Competition and Consumer Act 2010 (CCA).

This submission by RBB Economics comments only on the second of these policy measures and specifically on the approach Treasury adopts in the CP to define a "reasonable" price.[1]

The RPP in the CP attempts to protect domestic gas users from the higher (and more volatile) prices they now face since the gas market on the east coast was exposed to international gas prices.

We consider that a price that would emerge under competitive conditions is inherently "reasonable" from a competition perspective, even where such a price might be unpalatable for some users. It is then unreasonable to suggest that such pricing results from a failure of

[1] Although RBB Economics has advised both gas suppliers and industrial gas users on competition matters in the past, this submission has not been prepared for, or on behalf of, any client.

competition, and to seek to use competition powers to enforce pricing below such levels. In other words, the RPP proposes a pricing rule which will almost certainly result in pricing outcomes that diverge substantially from those that we would expect to emerge under competitive conditions.

The protection of consumers from high prices may be precisely what Treasury is hoping to achieve with this policy. However, the RPP would not only replace a commercially negotiated price with a regulated price, but base that regulated price on the wrong measure. It will reflect the opportunity costs that were relevant prior to the structural changes that took effect from 2015 rather than the opportunity costs facing producers today. This leads to the risk that a distortion will be introduced into the gas market, causing an inefficient allocation of resources and a reduction in important investment incentives for gas producers. These incentives are crucial in encouraging necessary new investments to be made that are much more likely over the long-term to deliver better pricing outcomes for domestic users than the proposed interventions.

The remainder of this submission is structured as follows:

- Section 2 provides an overview of the structural changes that took place in the east coast gas market from 2015.
- Section 3 explores the distributional consequences of that structural change.
- Section 4 presents the main shortcomings of the RPP proposed in the CP that we believe will lead to undesirable economic outcomes.
- Section 5 concludes.

2 Structural changes in the east coast gas market

2.1 Prices for gas under the previous market structure

Prior to 2015, demand for east coast gas was around 700 PJ per annum. Almost all of this demand was met using gas from conventional reserves,[2] a significant share of which came from the Cooper Basin, located across the northeast of South Australia and southwest of Queensland.[3]

Importantly, natural gas cannot be exported unless it is converted to liquified natural gas (LNG). This requires that the natural gas is cooled and condensed into a liquid at purpose-built LNG “trains” where it can be loaded on to specially designed ships and exported. Once the LNG arrives at its destination, it is regasified, and injected into pipelines to be delivered to customers.[4]

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[2] Conventional gas reserves largely consist of porous sandstone formations capped by impermeable rock. Gas flows to the production well and to the surface under high pressure. It is then processed and transported through high pressure pipelines to customers, including large industrial gas users.

[3] ACCC, Inquiry into the east coast gas market, April 2016, page 1.

[4] ACCC, Inquiry into the east coast gas market, April 2016, page 25.

There were no "trains" capable of liquifying gas on the east coast before 2015. All the conventional gas was used to service the domestic market. Gas from the Cooper Basin supplied the South Australian market via the Moomba to Adelaide Pipeline System, and the New South Wales market via the Moomba to Sydney Pipeline.[5]

The inability to liquify and export gas prior to 2015 meant that the global spot or contract price of LNG was irrelevant to the domestic price of contracted gas for domestic users on the east coast of Australia (in gas supply agreements or GSAs with domestic gas producers).[6] Instead, domestic prices were determined through commercial negotiations between consumers and producers using a cost-plus formula. Typically, this negotiated price was based on the producers cost of production plus a margin and escalated with inflation. The ACCC in its 2016 *Inquiry into the east coast gas market* noted that, historically, gas buyers typically had few difficulties renegotiating their GSAs when they expired and that non-price terms such as the duration of GSAs, price review mechanisms, quantities (including flexibility on delivered quantities) and delivery locations were typically rolled over from one GSA to the next and remained relatively stable.[7]

However, on 6 January 2015, the way that the price that domestic users paid for gas in the east coast market was determined changed forever. On that day,[8] the first cargo of LNG was exported from one of the six new LNG trains constructed in Curtis Island in Queensland. Those new trains created a surge in demand (due to exports from LNG projects) for gas in the east coast market – from 700 PJ per annum to around 2,200 PJ per annum. That new demand would be met predominantly by the development of unconventional gas fields (using coal seam gas or shale gas). In some cases though, LNG exporters' demands for gas might exceed the additional supply from these new sources.[9] In these cases, LNG exporters could be expected to seek to purchase gas from other gas suppliers (including non-LNG producers), then liquefy and export it.[10]

2.2 Prices for gas in the new market structure

What that meant for gas contracting is that the east coast gas market was now exposed to international LNG prices. In other words, suppliers could choose to sell their gas to domestic users located on the east coast or to buyers in China, Japan, Malaysia, and Korea. The prices struck in the agreements with overseas buyers were set at a percentage of the Japanese Customs-Cleared Crude price, which closely tracks other major oil indexes (such as Brent Crude, West Texas Intermediate, Tapis etc).[11]

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5 ACCC, Inquiry into the east coast gas market, April 2016, page 29.

6 On page 147 of its 2022 State of the Energy Market Report, the Australian Energy Regulator notes that "currently there are no importation terminals operational on the east coast of Australia. This means that Australia currently can export but not import LNG". Australia's first LNG import terminal was anticipated to be the Port Kembla facility in NSW which was expected to take its first gas shipment by the end of 2023 (see, for example, Reuters 2022, Australia's first LNG import terminal seen ready by late-2023. [Available at: https://www.nasdaq.com/articles/australias-first-lng-import-terminal-seen-ready-by-late-2023]). However, delays have meant that gas supply is now anticipated for winter 2024. Given that imports of LNG were impossible prior to 2015, the global spot or contract price of LNG was irrelevant in setting the domestic price of contracted gas for domestic users on the east coast of Australia during this time.

7 ACCC, Inquiry into the east coast gas market, April 2016, page 29.

8 In practice, domestic industrial gas users expressed difficulty in renewing long-term GSAs in the two or three years leading up to the first export of LNG. See, for example, ACCC, Inquiry into the east coast gas market, April 2016, page 30.

9 ACCC, Inquiry into the east coast gas market, April 2016, page 5.

10 ACCC, LNG netback review, Final decision paper, September 2021, page 21.

11 ACCC, Inquiry into the east coast gas market, April 2016, page 31.

The coupling of domestic prices with the international LNG price affected customers in the east coast in different ways. Customers located closer to the LNG trains (for example, those users in Queensland) were likely to be charged a price that reflected the global spot or contract price for LNG. Specifically, those customers were likely to be charged the LNG export price in Asia less the short-run costs associated with liquification and shipping the gas internationally. This price is referred to as the “LNG netback”.

Customers in southern states (further away from Queensland) were also impacted by the exposure to international prices. Those customers could (prior to 2015) purchase gas from the Gippsland Basin, the Cooper Basin, and the Surat Basin. The development of the LNG trains meant that substantial volumes from the Cooper and Surat Basins were increasingly being diverted to supplying the LNG projects. Many gas users faced offers at substantially higher prices and on less flexible terms than in the past.[12]

The ACCC notes that under the new market structure, domestic prices are likely to fall between a range of potential pricing outcomes. For a buyer in the southern states wishing to purchase gas, the only alternative to one of the few local supply alternatives is to purchase gas produced that would otherwise have been sold as LNG. The local domestic supplier could charge the buyer the LNG netback price at Wallumbilla plus transport costs from Wallumbilla to the buyer’s location and still secure the sale. The ACCC refers to this as the “buyer alternative”.

However, if there were sufficient supply alternatives available for domestic gas buyers in the southern states, competition would drive suppliers in the southern states to offer a gas price closer to their next best sales alternative. Under the new market structure, this alternative could be to sell gas to the LNG projects in Queensland. In this case, domestic buyers would need to pay the LNG netback price at Wallumbilla less the cost of transporting gas to Wallumbilla and the processing costs at Moomba or it would become more profitable for local suppliers to sell the gas to an LNG exporter. The ACCC refers to this as the “seller alternative”.[13]

As the ACCC noted in its 2016 inquiry, “where the domestic gas prices will ultimately end up is likely to depend on availability and diversity of gas supply in the southern states”. If supply (and supply alternatives) increased for customers in the southern states, the pricing outcomes would fall closer to the “seller alternative” price.[14]

Importantly, if the LNG netback price was to fall below domestic producers’ marginal cost of production, it would (once again) be irrelevant in setting the domestic price for gas.[15] [16] In this

12 ACCC, Inquiry into the east coast gas market, April 2016, page 24.
13 ACCC, Inquiry into the east coast gas market, April 2016, page 6.
14 ACCC, Inquiry into the east coast gas market, April 2016, page 52.
15 On page 147 of its 2022 State of the Energy Market Report, the Australian Energy Regulator notes that “currently there are no importation terminals operational on the east coast of Australia. This means that Australia currently can export but not import LNG”. Australia’s first LNG import terminal was anticipated to be the Port Kembla facility in NSW which was expected to take its first gas shipment by the end of 2023 (see, for example, Reuters 2022, Australia’s first LNG import terminal seen ready by late-2023. [Available at: https://www.nasdaq.com/articles/australias-first-lng-import-terminal-seen-ready-by-late-2023]). However, delays have meant that gas supply is now anticipated for winter 2024. Given that imports of LNG are currently impossible, the LNG netback price would be irrelevant in setting the domestic price of contracted gas for domestic users on the east coast of Australia in a situation where the LNG netback price were to fall below LNG producers’ marginal cost of production.
16 The LNG netback price may decrease due to a fall in the international LNG price, an increase in transportation costs, and/or an increase in liquification costs.

case, although producers may be physically capable of accessing the international LNG market, it would not be profitable for them to do so. As such, the negotiated domestic gas price would be based on the producers cost of production, as was the case prior to 2015. Similarly, if LNG producers were unable to access the international market for some reason (e.g., due to transport constraints), then the LNG netback price would be irrelevant in setting the domestic price for gas which could not be exported.

However, provided the LNG netback price was sufficiently above LNG producers' marginal cost of production (and gas producers did not face any significant export constraints), the main effect of having the ability to liquify and export gas was that the price of gas for domestic users, particularly in the southern states, would no longer be based on a cost-plus formula, even under competitive conditions. Instead, prices would fall between the buyer and seller alternatives described above.[17] In either case, this will typically be linked to the LNG export price.

3 Distributional consequences of the structural change

As with many structural changes in the economy, the changes discussed in section 2 of our submission have had distributional consequences.

On the one hand, they have been beneficial for the Australian economy. Developing the LNG projects created tens of thousands of skilled jobs and contributed significantly to Australia's business investment, and consequently to Australia's GDP. The LNG projects also pay billions of dollars in royalties and taxes to Australian governments.

On the other hand, the LNG projects have adverse distributional consequences for some customers. If the global LNG price is higher than the domestic price for gas, the domestic price will increase to that higher price (or to LNG netback as discussed in section 2). LNG and non-LNG producers benefit from charging prices that are higher than they would be in the absence of the ability to trade gas internationally, but customers and – to the extent that the higher costs are passed on – consumers in Australia are worse off.

Exposing domestic customers to global prices as a result of the ability to trade gas is not necessarily bad news for domestic customers. It is not inevitable that global prices will be higher than domestic prices. If domestic users could import LNG, they would benefit from exposure to a lower international LNG price. This (in part) explains why a number of import terminal projects have been under consideration in NSW, Victoria and South Australia.[18]

However, as we outlined in section 2, what is inevitable is that the basis for setting prices will irrevocably change. If LNG and non-LNG suppliers can access export markets, the global LNG price represents the opportunity cost of that gas.[19] That is the price which we would expect to emerge under competitive conditions and achieve an efficient outcome. The

17 The prices would also, in practice be capped at the buyer's maximum willingness to pay and subject to a floor of the marginal cost of supply.
18 AER, State of the Energy Market 2022, page 147-148.
19 Provided the LNG netback price is above producers' marginal cost of production.

(efficient) costs of producing gas, including a reasonable return, are no longer relevant to setting efficient prices.

If it was clear at the time that the structural change was occurring that domestic customers would be worse off, then the government could have designed transitional arrangements to mitigate any potential adverse distributional effects. A "first best" solution may have been to impose a lump-sum, non-distortionary payment on the LNG producers (or any other beneficiaries or "winners" of the structural change) to compensate domestic gas users or any other "losers" who would be worse off as a result of the change.

Having missed the opportunity to put in place sensible arrangements that could have addressed some of the adverse distributional consequences of the anticipated structural changes in the east coast gas market, the government has been trying to address what it considers to be excessive gas prices in a number of ways.

First, in 2016 it asked the ACCC to undertake a market inquiry using the powers available under Part VIIA of the CCA which deals with price surveillance. It has since asked the ACCC to monitor the industry and report on the supply outlook, the domestic price outlook, domestic user experience and transportation and storage issues every six months.

Second, it introduced the Australian Domestic Gas Security Mechanism (**ADGSM**) – an export control mechanism which allows the Minister for Resources to determine if the following calendar year is likely to be a shortfall year, and if it is, to apply export controls on LNG exporters to limit the amount of gas they can export as LNG.[20] [21] Although the ADGSM officially came into effect on the 1 July 2017, it has yet to be invoked by the Minister.

In an attempt to avoid triggering the ADGSM, the government and LNG producers entered into a Heads of Agreement (**HoA**) which specifies that excess gas produced by the LNG producers (i.e., gas that is produced beyond their existing contractual commitments) must be offered to the domestic market for reasonable supply periods, with reasonable notice, on competitive market terms and at prices no more than international customers will pay, before being offered to the international market.[22] [23]

Finally, concerns about high prices faced by domestic gas users on the east coast of Australia seem to be at the heart of the policy proposals in the CP. Treasury predicts that that without the intervention, retail gas and electricity prices would increase by 20 per cent and 36 percent respectively in 2023/24.

The proposed RPP represents what would be the most intrusive of these interventions into the east coast gas market. The following section presents what we see as the shortcomings of the RPP, namely that the cost of domestic gas production (as defined in the CP), represents an inappropriate benchmark for the negotiation of "reasonable prices".

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20 ACCC, Gas inquiry, Interim report, July 2022, page 7.
21 Customs (Prohibited Exports) Regulations 1958, Division 6.
22 ACCC, Gas inquiry, Interim report, July 2022, page 7.
23 Heads of Agreement, The Australian East Coast Domestic Gas Supply Commitment. [Available at: https://www.industry.gov.au/sites/default/files/2022-09/heads_of_agreement_the_australian_east_coast_domestic_gas_supply_commitment.pdf

4 Shortcomings in the definition of a reasonable price

The main shortcoming that we discuss below is that the definition of a "reasonable price" proposed in the CP is not related to the opportunity cost LNG exporters face by selling gas domestically (i.e., the LNG netback price).[24] Instead, reasonable prices are defined in the CP as the efficient long run marginal costs of domestic supply, allowing for a commercial return on capital reflective of the industry's risk profile.

4.1 What is the right benchmark for the cost of east coast gas?

The definition of a "reasonable price" proposed in the CP has some intuitive appeal. Over time, effective competition might be expected to bring prices down towards efficient production costs.

Such an approach to "reasonable pricing" would make sense if there was a surplus of domestic production and some or all these suppliers of gas on the east coast were unable to access the export market. If, for example, suppliers could only sell their gas to domestic users, then we would expect that suppliers would compete and that prices would be driven down to the long run marginal costs of domestic supply, including a commercial return (although in theory, competition could drive prices down to the marginal cost of supply). This was the dynamic that operated in the east coast gas market before LNG producers gained the ability to liquify and export natural gas and prices were based on the cost of production plus a margin.

But suppliers in the east coast gas market <u>can</u> access the export markets. What this means is that LNG netback prices represent the opportunity cost of supplying gas to the domestic east coast gas market.[25]

The LNG netback price is a key factor driving LNG exporters decision about whether to supply their excess gas internationally or domestically.[26] When the LNG netback price is higher than the domestic price for gas, the LNG exporters' opportunity cost of selling the excess gas domestically is higher than their opportunity cost of selling the gas internationally (i.e., the value of the next best foregone alternative is higher when selling domestically). Put simply, LNG producers have an incentive to export their excess gas as LNG when the international price exceeds the domestic price.

As noted above, the domestic gas market faces a supply shortfall in 2023 if LNG exporters choose to sell all of their excess gas on the international LNG market.[27] The fact that the east coast gas market faces such a supply shortfall implies that domestic gas producers alone are unable to meet domestic demand for gas. Consequently, the ACCC is calling on LNG exporters to supply more of their excess gas into the domestic market to meet the demand which cannot be met solely by domestic producers. The excess gas is the marginal unit of gas which, in competitive markets, sets the price for the market as a whole.

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24 Assuming the LNG netback price is above producers' marginal cost of production.
25 Assuming the LNG netback price is above producers' marginal cost of production.
26 The LNG netback price is calculated by taking the price that could be received for LNG and subtracting or 'netting back' the costs incurred by the supplier to convert the gas to LNG and ship it to the destination port.
27 ACCC, Gas inquiry, Interim report, July 2022, page 10.

However, every GJ of excess gas LNG exporters supply to the domestic market represents a GJ of excess gas they have foregone selling in the international LNG market. In other words, the opportunity cost that an LNG producer incurs by selling a unit of their excess gas domestically is the LNG netback price.[28] Given the recent increases in the international LNG price, this opportunity cost is substantial.

The approach proposed by Treasury for what a "reasonable price" is, is instead based on the efficient long run marginal costs of domestic supply, allowing for a commercial return on capital reflective of the industry's risk profile. This will lead to a lower price than one set on the true opportunity cost, which is of course what Treasury is aiming to achieve with this policy measure. In our view such a price is more accurately described as a "regulated" price rather than a "reasonable" price.

But in circumstances where suppliers can lawfully and efficiently access export markets, a price that relates to the long run marginal costs of domestic supply does not represent the true opportunity cost and contains no economic meaning. A price based on long run marginal costs gives the impression of being an economically rational or sensible price, but in this instance has the effect of introducing a serious distortion in the way the prices for gas supply on the east coast are set.

Specifically, gas priced at this level risks that scarce gas resources are not allocated to the consumers who value them most (potentially resulting in a reduction in tax revenue from LNG exporters). Additionally, and perhaps more importantly, this price may reduce the incentives for gas producers to invest in additional capacity resulting in a reduction in dynamic efficiency and, in the long-term, a reduction in the supply of gas.

In our opinion, it would be unusual to label a market-based price that reflects the true opportunity cost that an LNG producer incurs by selling a unit of their excess gas domestically as "unreasonable" and to ask the agency tasked with administering the CCA to expose a supplier charging such a price to civil penalties. Such a price is one that we would expect to emerge under competitive conditions and which would be most likely to achieve efficient or desirable economic outcomes.

4.2 Prices can reasonably depart from costs in competitive settings

The proposed reasonable pricing provision creates a risk that "reasonable" prices will be defined with reference to the (efficient) costs of production and firms that set prices above that level – gas producers in this case – will be subject to civil penalties. However, economic theory shows that there is nothing inherently suspicious about prices that exceed the costs of production in both competitive and imperfectly (but effectively) competitive markets.

For example, in competitive markets characterised by increasing costs, the marginal firm in an industry charges prices at the level that recovers all of its economic costs. More efficient firms will, by definition, earn positive economic profits. This means that prices will more than cover the average total costs for the "infra-marginal" – that is, the more efficient – firms in the

[28] Assuming the LNG netback price is above producers' marginal cost of production.

industry.[29] In other words, the most efficient firms in the market will be receiving a price that is higher than the cost benchmark in the CP and would – if the policy applied broadly – be subject to civil penalties for being more efficient than other firms.

When charging prices for access to a facility that is capacity constrained, it may be efficient to set prices higher than the long-run average cost to manage congestion. In order to balance supply and demand, the price should be set such that the quantity demanded by consumers is equal to the quantity producers are willing to supply (i.e., the market clearing price). This implies that a market clearing price could be as high as the marginal consumer's willingness to pay.[30] A price that is higher than – and unrelated to – production costs is essential in instances where producers are capacity constrained and consumer demand exceeds this capacity. In these instances, higher prices benefit the community if they efficiently allocate scarce resources among consumers. Prices rise to a level high enough to ration scarce capacity on the demand side to balance supply and demand and reflect the (high) opportunity cost consumers place on reducing consumption by a significant amount on very short notice.[31]

An example of a situation where prices (efficiently) depart from costs in order to allocate scarce resources is spectrum licences. Spectrum licences are necessary for firms wishing to provide mobile, wireless and broadcast services. These licences are often issued to those firms at prices that far exceed the costs of managing or allocating that spectrum. There is now agreement among economists that the best way to assign scarce spectrum resources to those with the highest willingness to pay is through a mechanism such as an auction rather than through cost reflective pricing that would recover the costs of managing or allocating the spectrum.[32]

In the examples above, prices depart from production costs but do not give rise to a loss in efficiency. However, even if high prices do entail some losses in static efficiency, they can provide dynamic incentives for infrastructure owners to make further investments in capacity.[33] This is acknowledged by the ACCC in the July 2020 Gas Market Inquiry Interim Report when they note that the while the fall in LNG spot prices (at the time) has "brought some short-term price relief to domestic gas users", it also acts a signal to potential investors that future gas prices will be low. Therefore "producers that require finance to fund exploration and development may …find it difficult to do so in a low … LNG price environment".[34]

5 Conclusion

The east coast gas market underwent a serious structural change just over a decade ago. The development and construction of three liquified natural gas (LNG) projects in Queensland meant that domestic industrial gas users, that had enjoyed plentiful, cheap gas from a number

29 Bishop, S. and Walker, M. 2010, 'The Economics of EC Competition Law: Concepts, Application and Measurement', page 238.
30 Productivity Commission 2019, Economic Regulation of Airports, Report no. 92, Canberra, page 78.
31 Joskow, P. L. 2006, Competitive electricity markets and investment in new generating capacity. AEI-Brookings Joint Center Working Paper, (06-14), pages 8-10.
32 See, for example, Coase, R. 1959, 'The Federal Communications Commission', Journal of Law and Economics.
33 Productivity Commission 2019, Economic Regulation of Airports, Report no. 92, Canberra, page 78.
34 ACCC, Gas inquiry, Interim report, July 2020, page 18.

of suppliers, now faced very different competitive conditions. Supply options for these customers dried up as gas was diverted to higher-valued uses, contract renewal became more uncertain and difficult, and the prices they paid for gas were higher than before.

Domestic users have paid higher prices for their gas, but these higher prices appear to reflect the interplay of supply and demand under a new market structure whereby the east coast gas market was exposed – for the first time – to global prices.

While the CP (and the ACCC through its inquiries) suggest that competition may not be as strong or effective as the ACCC would prefer, the highly volatile international gas market means that gas prices would likely be high even in markets subject to effective competition. The government's desire to intervene to protect users from facing higher prices seems to be driven, instead, by a (perhaps understandable) desire to achieve distributional objectives, namely, to achieve a fairer deal for buyers of gas on the east coast.

Governments are, of course, entitled to seek any policy objective they desire. But in this case, they are seeking to achieve that goal by setting prices that relate to the long run marginal costs of domestic supply (plus a reasonable return).[35] While that cost benchmark may have represented the cost of supplying gas in the period before the gas market was exposed to international prices, it does not represent the relevant cost for suppliers in the east coast gas market today, which reflects the opportunity cost of selling gas for LNG export.

Simply describing the proposed pricing mechanism as reasonable does not make it so. A price that would emerge under competitive conditions is reasonable. As the ACCC acknowledges, the prices that we would expect to emerge under competitive conditions relate to LNG netback. As a result, LNG netback prices represent the opportunity cost of supplying gas to the east coast gas market.[36]

Setting a price that reflects a different – and irrelevant – opportunity cost may achieve a particular distributional objective, but it should not be labelled as a "reasonable" price. There is nothing reasonable about a manufactured price introduced into a workably competitive market to placate one group in the economy if that price cannot convey to all participants in that market that worthwhile new investments are urgently required. A better description for the proposed price would be a "regulated" price. Describing a price as "unreasonable" because it departs from costs may discourage efficient and socially desirable outcomes from being achieved.

If the ACCC – as the agency tasked with enforcing the mandatory code and reasonable pricing provision – adopts such an approach to what is or isn't a reasonable price, it would represent a major departure from the generally economically sound approach it takes to intervening in markets and could serve as dangerous precedent in other aspects of the ACCC's important work.

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[35] Where the long run marginal costs of domestic supply do not relate to the opportunity costs LNG exporters face (i.e., the LNG netback price).

[36] Assuming the LNG netback price is above producers' marginal cost of production.