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7 February 2023

Gas Market Consultation
Labour Market, Environment, Industry and Infrastructure Division
The Treasury
Langton Crescent
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Submitted via email: GasMarketConsultation@treasury.gov.au

Options to ensure the domestic wholesale gas market delivers for Australians – Submission

We welcome the opportunity to provide our submission in response to the Consultation Paper released in December 2022, particularly in the context of helping ensure ongoing reliable gas supply for businesses and communities in Eastern Australia.

We have set out in Part A of the Annexure to this letter background on Cooper Energy Limited ("**Cooper Energy**"), and our submissions regarding (i) the importance of local gas supply and (ii) what we propose is needed to support new gas supply.

Cooper Energy is an Australian company focussed specifically on the production, development and exploration for gas offshore Victoria for supply to customers in South-east Australia. We have not made profits, super or otherwise, during the period of the Russian invasion of Ukraine.

A voluntary code of conduct was agreed in September 2022 which included input from the Australian Competition and Consumer Commission (the "**ACCC**"). Cooper Energy is a signatory to that voluntary code, and believes that it should be given an opportunity to take effect before any alternative code – including the proposed mandatory code of conduct described in the Consultation Paper (the "**Mandatory Code**") – is developed.

However, in the event it is determined that the voluntary code needs to be replaced, in Part B to the Annexure we have set out our comments on the proposed Mandatory Code, including our responses to the relevant questions set out in the Consultation Paper.

This submission is endorsed by the Cooper Energy Board of Directors.

What is needed to support new gas supply

The Eastern Australia domestic gas market is currently facing the following key issues:

1. the increased value of gas as a global commodity is creating cost challenges for some gas users;
2. the domestic gas supply outlook is uncertain, as production from existing gas fields is declining at a faster rate than new supply is being developed; and
3. the cost of new gas supply is increasing as the new resources close to the market are smaller than the foundation legacy resources and/or more distant from the market which means higher transport and delivered costs.

We note that the Government recognises the need to retain incentives for future gas development and allow producers to make a reasonable return on investment. However, the proposed Mandatory Code – and specifically the reasonable price mechanism ("**RPM**") proposed to be included in the Mandatory Code – risks significantly curtailing much needed and already lagging investment in new gas supply.

Longer-term cost pressures and energy security concerns will very likely be much more severe if policy settings and regulations do not support needed investment in new competitive supply.

Cooper Energy's key concerns with the Mandatory Code and the RPM requiring resolution and suggested solutions are:

- **Foundational contracts to bring new gas supply should be excluded from the application of the Mandatory Code:** Gas supply agreements ("**GSAs**") to underwrite investment in new supply from possible reserves (or contingent or prospective resources) are typically bespoke to the opportunity and customer, and therefore need to be excluded from the Mandatory Code for reasons outlined in the attachment.

- **Clarity is needed over the meaning of "reasonable price":** The RPM must be set to recognise the cyclical nature of gas prices and the inherent uncertainty of forecasting the full lifecycle cost of gas projects, from exploration through development to production and abandonment/restoration. If the RPM is not clear and the appropriate price, it can be a significant risk for the critical equity and debt funding required to support gas projects. The RPM must be set by reference to a benchmark based on a regasified LNG benchmark price. (Please see further detail in our response to Questions 3 and 5 in the Annexure, Part B.)

We appreciate the opportunities we have had to engage with the Government thus far, and welcome the opportunity to discuss further as soon as can be arranged.

Yours sincerely
Cooper Energy Limited

David P. Maxwell

David Maxwell
Managing Director & CEO

ANNEXURE
Part A

About Cooper Energy

Cooper Energy is an ASX listed company (ASX: COE), 95% owned by Australians. For the last 10 years we have focussed on exploring, developing and producing gas supply for South-east Australian customers. We employ over 120 people – soon to increase to 150 people – all of them in Australia and many in regional Australia. We are the only gas producer in Australia certified as carbon neutral by Climate Active, and we are a values-driven business, with actions guided at all times by our values.

Cooper Energy currently supplies approximately 6% of South-east Australian[1] gas demand, with plans to invest to increase this contribution to 15% by 2030.

Over the past seven years Cooper Energy has invested over one billion dollars to build a business around two gas supply hubs. This twin-hub business includes:

- producing gas fields in the Gippsland and Otway basins (offshore Victoria); and
- onshore gas processing plants located at Orbost and at Port Campbell, both in regional Victoria.

During this same seven-year period we have focused on growing the business. This has involved raising $530 million in equity from shareholders, paying $20 million in petroleum resource revenue tax, no dividend payments to shareholders as yet, and recording a cumulative net loss after tax of $225 million. We are a growing Australian business focused on supply to the domestic market. We have not made profits, super or otherwise, during the period of the Russian invasion of Ukraine.

The Cooper Energy approach is to pursue win/win solutions and long-term relationships with partners and key stakeholders – including State and Federal Governments, our customers, the communities in which we operate, other producers, our service providers and our financiers – while keeping jobs and revenue here in Australia. This approach aligns with the stated objectives of the Mandatory Code.

The importance of local gas supply

In its Gas Inquiry January 2023 Interim Report released on 27 January 2023 (the "**January Report**"), the ACCC concludes that to avoid shortfalls in the longer term, additional gas supply will be needed from many new developments across many basins, in addition to one or more LNG import terminals.

It has been estimated that new developments and projects will account for 48 PJ/year of gas supply for South-east Australia by 2025/26[2].

Given the lead time required, the project and financial commitments for these new supply projects must be made no later than within calendar year 2023. If these commitments are not made this year, the demand for gas from Queensland and/or imported LNG will only increase further (by the gap created by these as-yet-uncommitted projects).

[1] Comprising VIC, NSW, SA, ACT and TAS.
[2] Anticipated supply taken from AEMO GSOO March 2022, figure 39.

For Cooper Energy specifically, the uncertainty created by the Government's gas policy intervention has clear and substantial implications for our next development and our next exploration program. If these activities do not proceed, the result is significantly less gas becoming available in Eastern Australian in the next 3 – 10 years.

Otway Phase 3 Development

The 2021 National Gas Infrastructure Plan illustrates that the most competitive new source of gas supply to South-east Australia is from the Gippsland and Otway basins. Aligned to this, we are currently undertaking Front End Engineering Design ("**FEED**") for the potential investment of up to $750 million in the Otway Basin, to develop up to 30 PJ per annum from 2025 onwards – known as the Otway Phase 3 Development ("**OP3D**"). A final investment decision ("**FID**") has been targeted within 2023, to support first gas production before the winter of 2025.

In January 2023 Cooper Energy announced that the timing of this investment is under review. A key factor in this decision was the Government's gas policy intervention announcements in December 2022. Without the OP3D project, the Cooper Energy-operated Athena Gas Plant near Port Campbell will most likely cease production with a resulting loss of employment, loss of the significant economic benefits that accrue from the plant into the local economy, and loss of regional gas processing capacity and future gas supply growth opportunities.

Gippsland - exploration and near-term further developments

Over the past 5 years Cooper Energy has acquired several exploration permits and undertaken extensive geoscience studies in the Gippsland Basin. We have been planning a significant exploration campaign in the basin which, if successful, will deliver further new supply from 2028 of over 20 PJ per annum and further exploration of other prospects for later development.

However, we can only commit to the considerable costs associated with that exploration campaign, and subsequent development of discovered hydrocarbons, when we have certainty as to the gas market and the associated regulatory and fiscal environment.

Subject to those arrangements being acceptable, Cooper Energy is uniquely positioned with the focus, resources, infrastructure, capability, relationships and other key enablers required to continue to make a meaningful contribution to growing domestic gas supply this decade – where and when it is most needed, from gas supplies close to key demand centres, and accredited net zero.

Cooper Energy acknowledges the current challenges facing the Eastern Australia energy market. We support the objective of a gas reservation policy. We also note that the implementation of a gas reservation policy in Eastern Australia requires the cooperation and collaboration of Federal and State Governments.

New gas supply requirements

As stated in the Consultation Paper, the Government recognises the need to retain incentives for future gas development and allow producers to make a reasonable return on investment. However, the proposed Mandatory Code - and specifically the RPM - risk curtailing much needed and already lagging investment in new gas supply.

Following is more background on Cooper Energy's key concerns with the Mandatory Code and the RPM:

- **Foundational contracts to bring new gas supply should be excluded from the application of the Mandatory Code:** GSAs to underwrite investment in new supply from possible reserves (or contingent or prospective resources) need to be excluded from the Mandatory Code.

  These long-term GSAs are fundamentally different to standardised GSAs for the supply of developed gas – they have bespoke terms, enable new supply and generally involve only large/sophisticated gas buyers. Further, as GSAs are the key foundation and enabler for new gas field development – including financing successful developments – the negotiating power imbalance is often reversed from that targeted in the proposed Mandatory Code and RPM.

  It is for these reasons that undeveloped reserves, and contingent and prospective resources, are excluded from the current voluntary code of conduct – and why they must be excluded from the Mandatory Code. Bringing these types of contracts under the operation of the Mandatory Code will have a direct and material negative impact on the ability of new gas resources to be funded and developed.

- **There is a lack of clarity over the meaning of "reasonable price":** It is inappropriate to set the RPM by reference to a form of "building block" methodology reflecting only the long-term costs of bringing gas to market.

  The RPM must be set in a way that recognises the cyclical nature of pricing in gas markets over the life of an investment – with the risk that costs might not be recovered in full at certain points in the price cycle. The RPM must recognise the inherent uncertainty of forecasting and measuring the full lifecycle cost of bringing gas to market (exploration + development + production + abandonment/restoration).

  In order to:

  (a) meet the Government's objective to maintain incentives for investment in new sources of supply;

  (b) give customers confidence that they will pay no more than a reasonable price; and

  (c) avoid substantial costs, delays and inefficiencies associated with private arbitration of a complex commodity such as gas, and the many and variable terms of GSAs,

  we believe that the RPM must be set by reference to a clearly defined and economically appropriate benchmark mechanism established by the ACCC, and that this benchmark mechanism should be based on a regasified LNG benchmark price. Further detail is included in our response to Questions 3 and 5 in Part B of this Annexure.)

ANNEXURE
Part B
Responses to questions in the Consultation Paper

1. Are the obligations outlined in the voluntary code (summarised at Appendix C), if made mandatory, adequate to address bargaining power imbalances between gas suppliers and purchasers in the negotiation of gas supply contracts?

The Consultation Paper states that the key design objectives of the Mandatory Code are that it should:

- *Address bargaining power imbalances between producers and buyers in the domestic wholesale gas market.*
- *Set minimum standards for dealings between producers and buyers, ensuring a clear and certain commercial negotiation framework.*
- *Support producers and buyers to arrive at agreements on reasonable terms.*
- *Provide a reasonable pricing provision to ensure that domestic prices are set at reasonable levels given the underlying costs.*

Meeting these design objectives successfully requires the application of the Mandatory Code to be specific, rather than applied to all GSAs. In particular, the Mandatory Code must allow for differences between:

1. sophisticated sellers (both producers and retailers) contracting firm gas supply to many small and less sophisticated buyers, generally done through a tender or EOI process ("**Firm GSAs**"); and
2. small producers bilaterally negotiating bespoke gas supply arrangements for the development of new fields and undeveloped resources with large, sophisticated gas buyers (typically large retailers and large industrials) ("**Foundation GSAs**").

Firm GSAs

The majority of wholesale domestic gas demand in Eastern Australia is transacted under Firm GSAs with terms of 1-3 years, supplied from developed gas reserves. The majority of this gas is supplied by either:

- large producers selling gas at the outlet of their gas plant to a buyer (a retailer or end user who will transport the gas to the location where it is consumed or stored); or
- retailers selling gas to one or more buyers at the location(s) where the gas will be consumed.

The terms and conditions of these wholesale Firm GSAs are largely standardised. For competitive reasons, it is common for producers to run EOI processes and buyers to run tender processes. Retailers may engage with both producers and gas buyers.

For Firm GSAs, Cooper Energy recognises that power imbalances may exist between a producer or retailer (as sophisticated market participants) supplying gas to less sophisticated buyers. The voluntary code of conduct was developed to address these concerns.

Foundation GSAs

As noted in our covering letter and Part A of this Annexure, Cooper Energy is focused on the commercialisation of conventional gas fields, mainly offshore Victoria, close to key demand centres. The development of these gas fields typically requires the investment of hundreds of millions of dollars over a number of years. The fields are then generally in production for 5 – 10 years and must be decommissioned at the end of field life.

To attract funding in order to proceed with that investment – and reduce uncertainty around the bankability of the gas development to an acceptable level – a GSA for the majority of expected gas production is required. Foundation GSA arrangements are the foundation of new supply.

These Foundation GSAs are unique in that, among other factors:

- they are entered into with a long lead time prior to first gas supply (i.e. 3 years or more) – the resulting supply term often extends beyond the buyers' target focus period where greater uncertainty exists regarding market conditions;
- the terms may include flexibility on start date and volume – resulting in a benefit to the seller which the buyer is required to manage within its gas supply portfolio;
- the creditworthiness of the buyer is important to financiers; and
- Foundation GSAs represent a very small percentage of total GSAs in the East Coast market.

The terms of these Foundation GSAs generally limit their suitability to sophisticated participants (retailers, producers and some large industrials). In these circumstances, the power imbalance can be the reverse of that for Firm GSAs, as the customer is the enabler for the project.

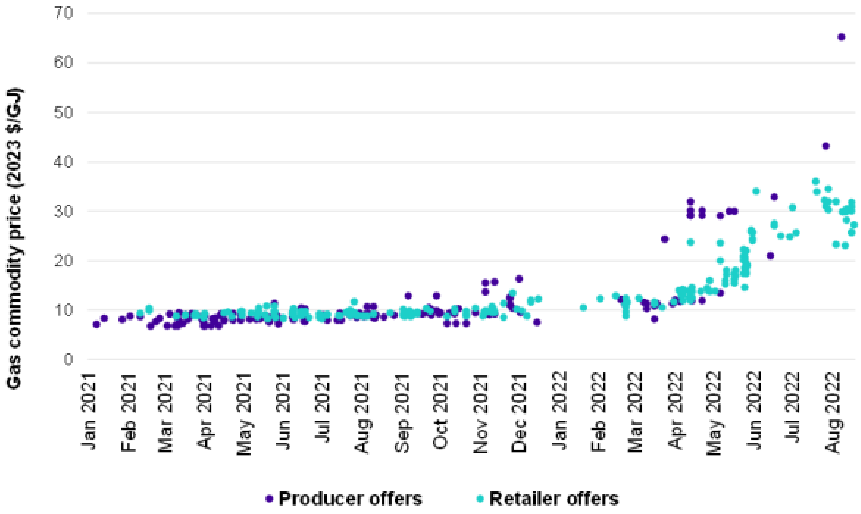
The timeline for negotiations of these Foundation GSAs runs in parallel to the project's FEED phase, in order that the Foundation GSA can be finalised to support a positive project FID. It is not appropriate for these negotiations to be governed by a pre-determined EOI processes or face the risk of lengthy and costly arbitration before they can commence.

For these reasons, GSAs for undeveloped gas or contingent or prospective resources (e.g. resources, pre-FID, before being recognised as reserves) were excluded from the voluntary code of conduct. The Mandatory Code should be structured on the same basis so that it supports the development of new gas supply – and not impede new supply.

2. **Should the Code of Conduct be limited to wholesale contracts where the supplier is a gas producer, or be expanded to include contracts offered by other market participants, such as retailers? This need not broaden the application of the reasonable pricing provision.**

The ACCC's bids and offer chart below illustrates that retailer offers have an important role in gas supply of at least 0.5 PJ per annum to end users in the East Coast market.

Chart 1 – Gas commodity prices (2023$/GJ) offered in the east coast gas market for 2023 supply



Source: ACCC

Gas buyers located within a regional gas distribution network that do not wish to, or are unable to, purchase gas directly from producers are required to purchase gas from a retailer. Due to the costs of managing day-to-day nominations, transportation agreements and regulatory compliance, it is not common for buyers consuming less than 1 PJ pa to contract directly with a producer.

The ACCC in its January Report noted that between March and August 2022, the average price agreed by producers for 2023 supply was $12.38/GJ (compared with $17.51/GJ for retailers) – with the average retailer price increasing significantly more than the average producer price. In previous reports, the retailer premium has been less than $2/GJ, generally reflecting a delivered product with generally more flexible terms.

Retailers were excluded from the voluntary code of conduct as it was prepared on behalf of the gas producers and coordinated by APPEA.

The terms and conditions of the retailer sales agreements will include transport and flexibility terms which are not included or can be quite different to those in a producers GSA.

We submit that whether the Mandatory Code is applied to retailers selling to gas buyers for volumes greater than 0.5 PJ pa is an issue that needs more analysis to fully understand any implications for the market.

3. How could the binding arbitration process be designed to ensure resolution in an efficient and cost-effective manner, particularly with regard to reasonable pricing?

We propose that the arbitration process defined in the Mandatory Code should reference a relevant and publicly available market pricing benchmark. A buyer should not be able to pursue an arbitrated outcome if the price offered to them is less than the established market pricing benchmark. Cooper Energy outlines its views on the factors that should be considered in determining a reasonable price in the response to Question 5 below.

We note the importance of equity and debt funding for the critical new capital investment to maintain and grow gas supply. To support such funding a valid and transparent benchmark price is critical.

Such a system would have some similarities to the “reference tariff” regime which is overseen by the Queensland Competition Authority (“**QCA**”) for access to Aurizon’s rail network, and which also applied in relation to access to regulated coal terminal services for many years. Under this system, access seekers are able to engage in commercial negotiations which are subject to a binding arbitration. Supporting efficient negotiations and arbitrated outcomes, the QCA sets a defined reference tariff through its regulatory process which effectively binds the arbitrator, unless a party to the arbitration can show that individual circumstances justify departure from that reference price.

Cooper Energy understands that the reference tariff system has proved highly attractive to access seekers in these regimes (equivalent to gas buyers from the perspective of the proposed Mandatory Code), as it provides a clear and transparent process for setting a reference tariff without the costs, delays and expense associated with private arbitration.

An important caveat to this system – which would reflect the different nature of gas markets – is that if a matter *is* referred to arbitration by a buyer, the producer should remain entitled to contract the subject gas on more favourable terms (including a higher price) if an alternative buyer exists. This concept is critical given that the gas supply outlook is currently short to demand, and will help ensure that gas is accessible for the highest value use.

Without this concept, in circumstances where there is a real possibility that not all gas demand will be fulfilled, allowing arbitration where there is an alternative buyer that is willing to pay more for the gas that exists means that scarce gas resources would ultimately be allocated either to:

- the party who happens to be “first in line” and able to refer the matter to arbitration first; and/or
- a party who has the ability to on-sell the gas to another party for a higher value, meaning that this first buyer would receive the full value of this commodity, and not the gas producer who has invested in developing and maintaining the resource to supply gas.

Such outcomes would be, we submit, contrary to the stated objectives of the Mandatory Code.

4. On what grounds should a party to a gas supply agreement negotiation be permitted to refer a dispute to a binding arbitration process? Should mediation be a pre-condition to accessing arbitration?

It is of critical importance that the initial conditions for referring a commercial dispute to binding arbitration be clearly defined and not create perverse incentives for parties involved in commercial negotiations. Arbitration processes are often costly and lengthy, particularly in the context of a complex commodity market such as domestic gas. They also tend to threaten the ability for normal commercial negotiations between the parties.

As a threshold matter, for the reasons outlined above, Foundation GSAs should not be subject to arbitration. These are a different type of contract to those for which the Government has concerns about imbalances in the respective negotiating powers of the buyer and seller, and are bespoke contracts negotiated as part of funding and investing in new gas supply.

Binding arbitration should also not be available to one buyer (“Company A”) if the seller is actively engaging with another buyer or buyers that are willing to contract at the terms currently on offer to Company A. If arbitration was available to Company A in this situation, then Company A could use the binding arbitration process to gain a commercial advantage over other buyers simply by virtue of being the first party to refer the negotiation to binding arbitration. This creates perverse incentives, and would lead to the negative outcomes identified above (i.e. that potentially scarce gas resources would be sold to the party that is either simply "first in line" and/or to parties that have the ability to on-sell gas to another user and thereby extract the full value of the product themselves).

Subject to the above limitations, Cooper Energy believes that a dispute should only be referred to a binding arbitration process when, terms that are well outside normal commercially negotiated terms, are on a final and "take it or leave it" basis, without the prospect of further negotiation. Regarding price, parties should only be able to refer a dispute where a final price offer is significantly above or below the benchmark posted price.

Mediation should be an option for the parties. However, this should not be a pre-condition, as a key requirement for a mediation is that both parties believe there is a good chance of an agreed outcome. Compulsory mediation that is imposed against the will of one of the parties is only likely to add additional cost and expense to the process. That said, there should be flexibility for an arbitrator to encourage the parties to mediate if the arbitrator believes this could be successful.

5. On what basis should an arbitrator be able to make a determination on price?

– What factors should be considered for the reasonable pricing provision?

– What type of guidance on reasonable pricing should be provided to support negotiations, and if necessary, arbitration?

The Consultation Paper states:

> *The reasonable pricing provision will provide a basis for producers and buyers to negotiate domestic wholesale gas contracts at 'reasonable prices', defined as efficient long run marginal costs of domestic supply, allowing for a commercial return on capital reflective of the industry's risk profile. This would be assessed with reference to the cost of the most likely new domestic gas production to meet forecast domestic demand, including:*
>
> - *operating expenditure reflecting efficient new development(s);*
> - *depreciation based on the economic life of the new development(s);*
> - *return on capital (set as a benchmark return reflecting the financing costs of an efficient business facing similar risks); and*
> - *an allowance for taxation and royalties.*
>
> *The depreciation and return on capital would reflect the capital costs of identifying and bringing new developments to market, including capitalised exploration and development costs. This will maintain incentives for exploration and supply of gas to the domestic market.*

Impact of uncertainty in determination of reasonable price

Producers invest in gas exploration and development where the risk-adjusted and probability-weighted discounted future cash flows of possible successful commercialisation scenarios sufficiently outweigh the costs of possible failure scenarios.

The inputs used in these calculations include:

- technical probability of finding gas and commercial probability of an economic development;
- possible recoverable gas production volumes over the field life;
- exploration costs, including seismic acquisition, geoscience studies, exploration and appraisal drilling (both successful and unsuccessful) and other past costs;
- development costs;
- operating costs during the production phase;
- abandonment and decommissioning costs[3];
- allowance for taxation and royalties;
- owners' costs; and
- threshold return on investment.

The proposed RPM approach outlined in the Consultation Paper appears to be based on the "building block model" that is commonly used in relation to regulated monopoly assets. The success of that model relies on the ability to accurately forecast the relevant usage and cost inputs to set reasonable tariffs, which are typically reset on a periodic basis (e.g. every 5 years).

A building block model is not suitable for gas exploration, development, production and restoration given:

- the significant and inherent uncertainty of inputs driving future cash flows which cannot be reliably forecast – as an example, these uncertainties could lead to possible break-even equivalent gas prices in the range of $8/GJ to $17/GJ (i.e. high production and low costs vs. low production and high costs);
- gas is a tradable commodity subject to price cycles – the proposed approach only sets a maximum price and does not guarantee a floor price, meaning returns are likely to be lower over time than what is determined as 'reasonable', with the result that, unlike regulated monopoly assets, producers are not guaranteed that they will receive revenues sufficient to cover their reasonable costs;
- due to the cyclical nature of demand for key equipment used to develop gas resources (e.g. drilling rigs), supply chain costs for the development of gas change significantly in line with changes to the underlying demand for, and value of, gas and oil as global commodities and are not able to be accurately forecast with certainty;
- the need to consider all costs (including restoration and rehabilitation) and differences in fiscal regimes applicable onshore vs. offshore Australia;
- uncertainty over production remains until late in a field lifecycle due to the difference in remaining reserves (e.g. 1P vs 3P), even if costs estimates are stable; and

[3] Although the Consultation Paper does not mention abandonment and decommissioning costs, they form a very significant cost of any development. For example, in 2023 Cooper Energy will decommission 7 wells and associated subsea infrastructure in the Basker, Manta and Gummy fields in the Gippsland Basin, offshore Victoria. The cost to complete the well abandonment activities is expected to be approximately $165 million on a 100% gross basis.

Cooper Energy's aggregate provision for abandonment and decommissioning costs across its portfolio totals $473 million as at 30 June 2022. The Mandatory Code, and the RPM specifically, must take these costs into consideration if the RPM is based on costs of domestic gas production.

- notwithstanding the uncertainty in future cash flows, determining a reasonable price based on a successful development scenario alone ignores technical failure case outcomes – as such, without suitable adjustment, this cannot result in a sufficient risk adjusted return to support investment in exploration.

These issues are particularly important for future investment in new gas supply, where the gas price required to support the exploration, development, production and rehabilitation of new gas fields is expected to be much higher than corresponding costs for the existing generational legacy fields (which are in decline). The unit supply costs have increased over time as the field sizes become smaller, capital and operating costs have increased and the larger resources are further from the market which requires then higher transport costs. Given these higher costs, Cooper Energy does not believe that a RPM resulting in a price cap similar to the current $12/GJ cap would be sufficient to encourage investment in new exploration and development.

Additionally, access to new capital from shareholders and financiers is accessible only on competitive terms taking into account the investment risks. In a commodities market, policies which have the effect of supressing prices and/or increasing uncertainty will likely result in a reduction in the all-important equity and debt capital availability and/or higher cost of capital available for investment into new supply.

In light of the above, the price (and other terms) for a new development – as set out in Foundation GSAs – should be subject to commercial negotiation only, not arbitration.

Cooper Energy believes that an arbitrator's ability to make a determination on price should be restricted to GSAs for developed reserves only and when it is clear that the price being sought is significantly above or below the benchmark (refer to response to Question 3 and this Question 5 below).

Long-term suitability of a reasonable price mechanism
The Consultation Paper suggests that the RPM would be assessed with reference to the cost of the most likely source of domestic gas to meet forecast domestic demand. Cooper Energy agrees that this could be an appropriate principle.

Consistent with this objective, Cooper Energy believes that LNG importation should be expressly confirmed as the most likely source of new gas supply that will meet forecast demand. Cooper Energy notes that one terminal (AIE) has already commenced construction and the ACCC recognises that LNG import terminals will be an important part of the future energy supply mix[4] for domestic demand. As such, the RPM should be linked-to a regasified LNG benchmark price in South-east Australia. This benchmark price could be reflective of a term supply of LNG, commensurate with the supply term under GSAs for which the RPM could apply and therefore not linked to short term 'high' spot LNG prices.

A regasified LNG benchmark price is an appropriate reference point because:

- As the future marginal source of supply, imported LNG provides a clear price benchmark to incentivise buyers to support the commercialisation of more competitive sources of domestic supply. Following the recently implemented $12/GJ price cap, and without an appropriate long-term price signal, buyers may otherwise wait in hope of further intervention and more attractive (although unsustainable) gas prices. If this alternate is not available (because it is not economic) the buyer will not be able to source supply.

[4] See January Report, Section 6.3.

- LNG import terminals are able to quickly increase supply up to their daily capacity, meaning that they will naturally take the role in market "swings" to avoid future shortfalls.
- New domestic production will need to be competitive with LNG import supply. The successful development of this new supply to meet demand based on commercially negotiated terms will result in gas prices below this benchmark level.

6. What design features will ensure the reasonable pricing provision provides a sufficiently clear basis for producers and buyers to negotiate a price?

Please see comments in answer to Question 5 above. We support an RPM aligned to a benchmark prices series reflective of the price of regasified LNG supply into South-east Australia with respect to Firm GSAs.

7. What model of arbitration should be used to resolve disputes about reasonable pricing?

As outlined in our response to Question 3 – 5, we consider that to facilitate efficient dispute resolution, the arbitration model should be based on:

- a reference price model analogous to the "reference tariff" model that has been successfully used for access to essential infrastructure in Queensland, with a reference price set by the ACCC based on a regasified LNG benchmark price; and
- clear principles governing which types of contract are subject to referral to arbitration and at what point in a commercial negotiation a dispute can be subject to referral.

Subject to these broad framework points, the specific model of arbitration should be based on a commercial arbitration framework. Australia has a number of well-established models of commercial arbitration which are governed by state and territory legislation, including the *International Arbitration Act 1974* (Cth) or the *Federal Court of Australia Act 1976* (Cth) (depending on the applicable contract specification and/or subject matter/jurisdiction in which the dispute occurs).

Commercial arbitration of this type in the energy sector commonly occurs in the context of long-term gas supply agreements which contain price review clauses. Disputes arbitrated in this way typically involve substantial time and expense for all parties involved in the dispute. However, this is not because these disputes follow a model of commercial arbitration, but because the arbitrator in these disputes is required to undertake the difficult and time-consuming task of determining an appropriate price by reference to the terms of the specific GSA. We believe that these issues could be avoided by establishing a transparent reference price framework as outline above.

8. Does the proposed model appropriately mitigate the risks associated with market intervention?

Cooper Energy can provide a response to this question when there is more clarity on the proposed model. The key considerations that Cooper Energy believes need to be taken into account are covered in the submission above.