THE UNIVERSITY OF QUEENSLAND
AUSTRALIA

Centre for Natural Gas

31 October 2019

Ms Lisa Gropp
Commissioner
Australian Government Productivity Commission
Locked Bag 2, Collins Street East
Melbourne VIC 80003

Dear Ms Gropp,

With reference to the Productivity Commission Issues Paper for Resource Sector Regulation (Sept 2019) and our brief discussions of 29 Oct 2019, please find below some initial comments.

The Centre for Natural Gas at the University of Queensland (UQ) was established in December 2011 as the Centre for Coal Seam Gas (https://natural-gas.centre.uq.edu.au/). It is funded by industry and UQ and increasingly through government competitive research grants. The purpose of the Centre is to conduct and support research and education relating to onshore gas development, coordinating a multi-disciplinary research program to address the range of community, government and industry challenges associated with the industry. The Centre, together with many colleagues across UQ, conducts research and supports education in key discipline areas including economics, business, petroleum engineering, geosciences, groundwater and social performance. The Centre also provides independent advice to stakeholders on policy and business-relevant matters, leadership on scientific and technical issues, as well as strategic planning. I have been the Director of the Centre since 2012. Prior to this I worked in the international oil and gas majors, in conventional and unconventional hydrocarbon exploration, appraisal and developments for over 25 years

In line with the International Energy Agency's 'New Policies Scenario' and 'Sustainable Development Scenario' (https://www.iea.org/weo2018/scenarios/), the Centre is focussed on ensuring a constructive role for natural gas in the ongoing energy transition. In both scenarios the supply of natural gas needs to grow supply *and* maintain affordability in order to fulfil key transition roles, *and* it needs to do this with the highest levels of operational *and* environmental performance.

Thank you for the opportunity to contribute to the issues paper via this brief submission. This submission represents the thoughts and views of the Centre Director, and are not necessarily those of the University or the Centre members. This submission is focused on Australia's onshore natural gas sector, just one industry in the broader range of resources which you are considering.

This note will be somewhat limited due to time constraints, but please don't hesitate to contact us if we can help further through your process.

EXPLICIT RECOGNITION OF THE NEED FOR TRADE-OFFS.

In starting this discussion, there are several matters relating to the general framing of the issues and investigations. This initial submission takes as read (but not for granted) that environmental standards should be high. All development (resource, agricultural, industry, housing etc.) inevitably requires consideration of trade-offs between some objective measures, some subjective measures and relative weightings of different types of "value" (government revenue vs. jobs vs. local investment vs. water vs. land vs. CO_2 vs. amenity etc.). Resource developments tend to be material, affecting many people far and wide, directly and indirectly, in real and perceived and obvious and not-so-obvious ways.

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THE COMPARATIVE NATURE OF THE INVESTMENT DECISION.

Noting that the inquiry seeks to examine regulation which has a "*material impact on investment*, it's important to consider perspectives of the investment decision makers. Attached is a draft discussion document prepared in May 2018 for the Commonwealth Department of Environment and Energy (Attachment A). This document explores (albeit simply and incompletely) the nature of investment decisions in the gas space and includes links to some relevant overseas experiences. Within this, it is important to explicitly recognise that attractiveness for investment is a *relative* or *competitive* assessment i.e. it should always be viewed relative to other overseas investment opportunities and environments. There are a number of areas which lend themselves to *comparative* consideration:

1. **The quality (risk and likely productivity) of the geology or resource**
   Compared to conventional resources such as those on the North West Shelf, unconventional resources are inherently second or third tier resources in terms of attractiveness. By and large, Australia's unconventional resources are probably not (at least not demonstrably) in the same class, and certainly not anyway near as mature, as "Marcellus shale", which is responsible for much of the US supply growth. There are very good indications of "gassiness", but the rocks are geologically old, with complex and different burial histories, a different stress-history and a different current stress state. They are also very remote on the world scale. In the US, hundreds of wells and 'failed' investments in field trials, preceded the shale boom. That activity was essential to enable an understanding of how rich their resource was *and* how to extract it. This has not happened here. With respect specifically to our coal seam gas (CSG) resources, they are highly variable and, looking ahead, less attractive (e.g. less permeable) resources may need to be developed. It is also important to remember, when thinking comparatively, that CSG is "dry" i.e. with no value adding liquids component[1].

2. **The *technical* costs (especially unit capex and unit opex)**
   "Unit Technical Costs" have to be estimated in advance of investment decisions. They are defined as the sum of the present value of the capex and present value of opex, divided by the discounted production. They are an indicator of a constant, pre-tax, real terms gas price (RTBEP) that a venture would require to break-even (Attachment A). "Break-even" is of course not the aim of an investment, but, especially given market (price) volatility, a venture does need to have an RTBEP above forward expectations of gas price to cover risk and be attractive.

   Australian onshore gas technical and unit technical costs tend to be *relatively* high due to resource quality and structural matters (such as geographic remoteness, employment costs, imports etc.). Our gas field supply chain, while very competent, does not have the scale, and our exploration and development activity levels do not support the degree of competition, seen in the US markets. Following extensive CSG developments, our operators and suppliers have shown an impressive ability to drive down some costs by learning, nevertheless it is extremely difficult to compete on cost with some competitor gas suppliers; and therefore, investment attractiveness is challenged. What works in our favour is that regional LNG demand is increasing and we may have a transport premium compared with some other future suppliers.

3. **The fiscal costs or government take**
   Government-take (State and Federal) is the direct benefit to governments. At its simplest, this is governed by the royalty and tax settings. A reduction (or delay) of government take can have a significant incentivising impact on new investment. In addition to simple rate reductions, other jurisdictions have employed a range of further measures such as accelerated depreciation, uplift, royalty holidays and exploration or R&D tax credits (see sub-heading "*Other government activity influencing investment*" below).

[1] We do not discuss here the relative value of liquid (oil and condensate) but we do note serious liquid fuel security concerns.

At its most fundamental, in a price-taker environment, it is the total unit cost (technical plus fiscal) together with total project risk which determines whether a resource is economic and can be brought to market. As discussed above, *comparatively*, onshore Australia is challenged on technical costs. However, it would be possible to tailor or tune fiscal settings to the *nature of the resource* i.e. for certain “challenged areas” an adjustment of government-take may lower the investment hurdle sufficiently.

By “challenged areas”, three specific situations come to mind (1) remote frontier, immature basins and plays (e.g. Beetaloo, Galilee, Georgina, Canning); (2) mature, late-life areas in decline (e.g. Gippsland, Otway, Cooper); and, possibly (3) technically challenged areas where gas has been shown to be present in major quantities but cannot be yet be made to flow at economic rates with existing technology (e.g. Bowen Basin). While by no means a full review, some links to experiences in other jurisdictions are included in Attachment A.

4. Likely timeframes from initial expenditure to first revenue

Given the above, the value to an investor of reduced cycle-times is self-evident. The matter was studied in some detail a few years ago. At that time, the Queensland Department of Natural Resources and Mines (DNRM, now DNRME) undertook development of a Queensland Gas Supply Demand Action Plan. While the plan has not been made publicly available, it could prove beneficial to this review if it could be sourced.

5. The overall “stability” or “predictability” of 3 and 4 above

The oil and gas sector is inherently marked by high levels of (resource and price) risk and uncertainty in advance of major investment decision making. Stability and gradual change in the regulatory settings are important. For example, a recent “overnight” announcement of royalty increases in Queensland is destabilising because it is not congruent with the stated aims of government to put downward pressures on gas prices and increase supply (in fact it does the opposite). Likewise, the post-Final Investment Decision threat of some form of domestic reservation (notwithstanding its inherent economic inefficiency) raises concerns about investability (compared to other jurisdictions). Anecdotally, it used to be said, in the early days of the North West Shelf development, that Australia could live with relatively high unit costs because of its low sovereign risk (compared to competitor supplies in the region and Middle East). The market is changing. Significant LNG supply will come onto the market from the US and Canada. These jurisdictions may have lower total costs and a similar, or even better, perception of stability.

6. Access to markets or restrictions put on sales (location or price)

For a positive investment decision, gas developments (to a far greater extent than oil) require a clear route to market, sales contracts and assurance that prices can be sought on a wide and open market. Exposure to stable, predictable off-take and to price “up-side” is required to cover the many of the down-side risks. Measures such as price controls, broad market supply obligations or threats thereof, such as Australian Domestic Gas Security Mechanism (ADGSM), are not inherently consistent with a policy aim of maximising supply or minimising prices. A number of references are included in Attachment B which explore implications of reservation mechanisms for resource owners (States) and operators. The alternative concept in Queensland of tenement release for domestic supply only, has the big advantage of being clear ‘up front’, which improves the investment environment from the perspective of predictability, though, if it impacts price significantly, it is not likely to improve the economic attractiveness. In essence both schemes, *if* they reduce prices materially beyond what could be otherwise earned, serve to transfer benefit from Queensland and Australia government revenues, and from gas companies, to a small number of large users (including some in States which elect not develop their own gas).

Maximising supply is a long-term goal which requires consistent investment attraction and open market access. The Queensland CSG developments, which now supply a large percentage of the East Coast gas market, only attracted investment because of the guarantees of access to export markets. As a resource, CSG has a higher unit cost of development compared to historic domestic supply. This could be partially compensated for by materiality (development at very large-scale).

Without investment in CSG-LNG, in the face of rapidly declining domestic conventional production, it is difficult to see how (long run aggregate) domestic gas prices could be lower.

7. **Willingness of government to co-invest in early (play opening) critical infrastructure**
The development of new gas basins and plays tends to follow a pattern. First, there is exploration activity over time, most of it unsuccessful (these investments need at least to be "risk-covered"). Often, this period includes smaller or low-rate gas discoveries which are "sub-economic". Essentially this means that the field is not big enough and/or the production rate not high enough to generate sufficient return on investment, *especially* if the initial investment includes a large, expensive pipeline to a remote market. Things can stall at this stage. Acceleration of this process can have significant public-revenue benefits. In this case, public investment or partial investment in new export infrastructure can be a significant accelerator for new, long term, gas to market.

THE NATURE AND DEFINITION OF "BEST PRACTICE"

The issues paper seeks to identify "best practice" in resource regulation. A better articulation, taking a contingency approach, would be to recognise that we mean "best fit" i.e. that the regulatory practice which "works best" is probably contingent on the physical, legal and market environment. That said, more consideration is also needed on what we mean by "works best".

The paper proposes three dimensions (Table 1) to assist with its definition. These dimensions are inherently "process measures" with an unwritten assumptions that (i) we know from experience what makes a good process; and conditional on that, (ii) what we think is a good process will deliver good (i.e. net beneficial) or even "best" outcomes. There is an opportunity to explore and define "best practice" with respect to *outcomes* (i.e. the degree to which outcomes that have been achieved by the process are line with resource policy objectives). For example, whatever processes we have in place at the moment and whether or not we deem these to be "good" or "best", the outcomes vis-a-vis stagnation of exploration activity are not in line with the stated aims materially to grow supply. Adopting both process and outcome measures allows for a "learning and review" loop which can inform policy and regulatory adaptation.

COMMUNITY AND COMMUNITY ENGAGEMENT

The issues paper at times refers to "community" engagement, impacts, benefits and so on. More consideration is needed into what is meant by "community" in this regard. What we see or is reported most often as "community" opinion is not demonstrably a representative sample of views of all people. Questions arise regarding what the legitimate boundaries of a community are, and who's views do we put (most) weight to; and how do views shift over time… and so on.. Some people are directly impacted more than others (e.g. by on the ground, industrial activities which attract compensation), benefits flow to residents in the State (e.g. via royalties which feed State government spend) and to Australians more generally (e.g. through federal taxes). Job creation is dispersed and is direct and indirect. Communities are heterogeneous, dynamic and overlapping. Communities in inner-city Brisbane may be quite influential in preventing (or promoting) development in distant communities in regional Queensland – in fact they may be more influential.

Our experience in respect of community engagement is quite extensive and includes a working knowledge of other, analogue jurisdictions. Rather than attempt to list this and associated references at this time, a strong recommendation is to conduct a follow-up discussion with Dr Kathy Witt, who is our Senior Social Science Research Fellow at the Centre and has been working in this area (related to onshore gas) for several years. She can guide you through the established practices and knowledge in this area and can connect you with other researchers in this space as needed.

"INFORMATION REQUESTS"

With respect to the "Information Requests" included within the issues paper, many of considerations are included in the above narrative. A few additional comments are included below:

Page 7: Inquiry scope, definitions and existing reviews

It may be necessary to separate streams for different resources types at a future date. But the proposed starting frame seems appropriate.

Page 9: Criteria for best practice

See discussion above. We would also recommend that other jurisdictions be examined (especially US, UK, Canada)

Page 11: Evaluation of current regulatory frameworks and options for addressing shortcomings

The question of "how" jurisdictions design regulations is important. The search for case histories from other countries is a sound course of action (e.g. links in Attachment A).

Page 14: Regulator governance – roles, accountability, independence, resourcing and outcomes

The information request seeks feedback on approaches to regulator governance. In the context of this letter, there has not been time to add substantial comment. There have been, however, three previously recognised regulatory approaches which we deem to have improved the operating, social and hence investment environment. These are (i) the Queensland GasFields Commission (QGFC) (https://gasfieldscommissionqld.org.au/) – we recommend that the inquiry refer to the 2016 review[2]; (ii) the LNG compliance unit; and, (iii) the Office of Groundwater Impact Assessment (OGIA). The latter, we feel is a most important innovation. The State government has built significant, internal technical expertise (at a world level) in large-scale, groundwater impact modelling. We note that the 2016 QGFC review also included a new institution (a Land Access Ombudsmen). This may also prove to be an important regulatory innovation, however, it is early days and we are not yet familiar with its operation and impacts.

The issues paper seeks information on regulator capability and on "under-resourcing". We recognise this to be a major challenge – especially the attraction and retention of high-end, industry-relevant technical skills in an environment which appears, from the outside, to prefer to move staff around rather than retain and grow sector specific expertise. It also struggles with a mechanism to compete with industry salaries. As far as examples of how things are done differently elsewhere, the Texas Railroad Commission and the United Kingdom Health and Safety Executive, amongst others, are potential case studies in how expertise might be accessed and maintained.

On the subject of whether or not "user pays" should be applied more broadly; my advice is to frame the *initial, high risk* exploration investment decision, as follows. The resource owner (the State) wishes a private entity to invest their at-risk-capital (in the State rather than elsewhere), so that, if they are successful, they can develop (for the State) a project which provides jobs and pays royalties and taxes (and yields private profits). The risk is all on one side and the majority of financial benefit accrues to the State/Commonwealth. In this context, it would seem wise to avoid measures which increase the already high, exploration investment hurdles by adding more up-front costs. The nature of the exploration investment decision is discussed briefly in Attachment A. "User does not pay", would seem more in line with enabling exploration. However, once a field is development-ready and risks are significantly reduced, amounts of capital are large, then, while a "user pays" model increases the development cost, it might be a significantly lower disincentive than it would be at the exploration stage. It is important to keep in mind that most exploration investment is <u>not</u> successful, but if increased supply is the aspiration, then *increased* exploration activity must logically also be.

Page 16: Regulator conduct – processes, outcomes, timeframes

The Centre recently undertook a review of Queensland's CSG development with respect to the International Energy Agency's *Golden Rules for the Golden Age of Gas (*https://webstore.iea.org/weo-

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[2] https://cabinet.qld.gov.au/documents/2016/Oct/RevGasComm/Attachments/Report.PDF

2012-special-report-golden-rules-for-a-golden-age-of-gas*).* Our full report requires more detailed discussion (a publication is in process but the Centre is happy to provide an early copy). However, in summary, it is clear that the State's or Sector's performance on the Rule relating to "disclosure" is where the greatest gap remains according to a range of community, regulator and industry interviewees.

With respect to regulator conduct and processes that are clear and transparent, in the context of Queensland CSG developments, the industry proponents were all conditioned to report a large number of compliance and performance metrics related to their environmental impact statement (EIS) approvals. The Centre is aware of a significant volume of reporting into government departments. It appears that there was no government plan to process, analyse or, more importantly, translate and make the data transparent for the public. In many cases, it is not clear who in government would be responsible (or resourced) for such public dissemination. By this we mean more than making datasets available online (noting that available is not the same as transparent). In assisting QGFC with development of a state of the industry report (https://gasfieldscommissionqld.org.au/shared-landscapes), the UQ Centre for Natural Gas found that the cooperation of State departments was excellent. However, in the main, information systems with respect to gas field compliance and performance reports are not designed with the intent of public dissemination and translation. The Centre has previously discussed with GFCQ the concept of an open industry, web-based dashboard or balanced scorecard, with independent, *translatory* commentary from the Centre. We still hold that this would be an excellent public service (as well as an open research resource) and would be more than happy to brief further on this idea.

Page 18: Other government activity influencing investment
The possibility to tune tax and royalty arrangements to the quality, location and maturity of the resource has been discussed above.

It is worth mentioning here that the current application and/or interpretation by the assessors of the R&D tax credit scheme is not fully in line with the objectives of increasing gas supply. R&D credits can significantly improve investability, especially at the high-risk exploration and evaluation (appraisal and pilot) stages. The current scheme fails to recognise that gas field appraisal, especially, but not only for unconventional resources, is essentially a research activity. The research is very location specific, such that, for example, drilling parameters, or hydraulic stimulation or choice of drilling fluids technology etc. in Basin A, does not inherently inform its suitability in Basin B. This requires research and experimental design (though typically under a different name). Numerous experimental trials are absolutely essential (as evidenced in the long build up to the eventual US shale gas revolution). The risk for these experiments is taken by an Operator, but if successful *and if shared*, then the tax-payer (policy goals) benefit by the commercialisation of a new resource. The incentivisation of greater degrees of experimentation (especially in the field) would be in line with the policy aims to increase gas supply. However, the application/scope of R&D credits is currently too limited and there are examples of assessments made without the requisite technical insights and expertise. Some concern that industry might abuse such a system seems to exist, this concern can be allayed by expert assessment.

Page 20: Effective and best-practice community engagement and benefit-sharing practices
Further engagement with UQ's Dr Kathy Witt could also cover access to our wide experience in indigenous engagement.

Our work suggests that it matters *who* does the engagement - the trust-rating of the "engager" is extremely important. Quality industry and regulatory engagement is absolutely necessary (silence is not golden). However, it is likely to not be sufficient. There is a trust 'ladder' and both government and industry tend to be relatively low down. While trust in societal institutions as a whole is reducing, the Universities and CSIRO tend to retain a high place. While clearly also in our interest, we feel that the promotion and dissemination of independent research can play a useful part in engagement.

ROYALTIES TO REGIONS AND SIMILAR IDEAS.
Early in the life of this Centre, the then Queensland Government proposed a scheme (since changed and/or renamed) to divert a greater share of royalties to the regions most affected by resource developments. It is a complex question to determine whether this direct form of hypothecation is an efficient use of public funds. Notwithstanding this, our view is that such a scheme needs to be

accompanied by additional emphasis on capacity building for local councils. Application for funding may be an exhaustive process and the optimal distribution of significant amounts of new income, in the face of local competing priorities, is likely to require additional resources and skills. Furthermore, for such a scheme to be effective in terms of regional attitudes, the amounts and benefits need to be public and transparent. Local capacity is also a key early focus area for the increased burden in both volume and complexity of local planning (industrial, residential/housing and environmental).

Thank you again for the opportunity for this discussion. We are more than happy to follow-up with additional information and perspectives.

Yours sincerely,

Professor Andrew Garnett
Centre for Natural Gas
University of Queensland

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ATTACHMENT A – May 2018 Draft Discussion Document. Study on Gas Supply Constraints for the Department of the Environment and Energy.

DRAFT Discussion Note

Prof AJ Garnett, Univ. Queensland Centre for CSG

STUDY ON GAS SUPPLY CONSTRAINTS FOR THE DEPARTMENT OF THE ENVIRONMENT AND ENERGY

Purpose.

The purpose of this brief note is to list ways in which investment decisions might be incentivised to increase gas supply. It is not intended at this time to be a complete or comprehensive document, nor to propose which of these measures might have the largest impact.

Introduction – focus on the investment decision

Generally speaking, there are a number of ways to accelerate gas to market in challenging economic circumstances, depending on what the main 'challenge'. This note will focus mainly on fiscal rather than physical , commercial or contracting measures. **All** gas supply additions and accelerations require investment. Therefore, in essence any action taken to increase supply has to demonstrate a way to make investment decisions easier i.e. more attractive. So, you have to understand (i) *how* these investment decisions are made; and, (ii) *that* these decisions are comparative i.e. there is a global choice where investment can be made. Note that "reserves" are not a good indicator of the ability to bring new rate to market or the cost thereof, remembering that reserves are the integral over time of the forecast (declining) production rate per well, field or company.

Discussion

I'll look at two types of investment decision (A) a reserves addition or acceleration in existing fields; and (B) exploration decisions. And, I'll keep the decision format very simple by referiung to simple evaluation types:

A) In-Field or Organic Reserves Additions: NPV positive @ WACC given a 'low-side' screening oil price.

NPV = PV{ Revenue(t) } – PV{ Costs }:

NPV = PV{ Production Rate(t) x Gas price(t) } – PV{ Capex(t) + Opex(t) + Royalty(t) + Tax(t) }

This leads to two basic types of measure; those required proportionally to increase the present value of life cycle revenues; and those require to proportionally decrease the present value of life cycle costs.

Revenue measures:-

- Price or price outlook is a given in most cases and will not be discussed here.
- Production Rate(t) is a function of technology optimisation *ceteris paribus*. New technologies can increase production rate and/or ultimate recovery. The latter might not *accelerate* gas to market *sensu stricto*. In either case, NPV will increase so long as (PV) costs do not proportionally

increase. Technology optimisation is *standard business* for companies. However, if positive investment decisions still cannot be made after the study or application of existing technical solutions, some incentivisation of R&D in general, and *technology trials in particular*, may be effective in getting a decision 'over the line', as may some change to the tax treatment of capital cost (e.g. depreciation, see below).

Cost measures:-

- Capital and operating cost (aka 'technical costs') optimisation is also *standard business* and in mature areas (e.g. Bass Straights, Gippsland and increasingly in CSG areas) significant unit cost ($/GJ) reductions have already been seen. However, as resources become more challenging e.g. more depleted reservoirs or, lower production rates / poorer reservoirs, or smaller pool sizes, then the ability to reduce technical costs may be exhausted leaving technically accessible gas economically stranded. In these circumstances, governments may choose to reduce fiscal costs (royalties and taxes) to match the quality of the remaining resource and/or to compete with other jurisdictions. Technical cost reduction and further innovation can be addressed with R&D subsidies (or tax credits) or even with direct capital subsidies (e.g. GAP).
- Fiscal costs (government take going forward). Globally government take varies widely and has to be tuned to the quality (part indicated by technical costs) of the resources available as well as risk. Mature, remote, technically challenging, low rate or small resources cannot support higher tax rates. An overview of global oil and gas taxes by country can be found at:http://www.ey.com/gl/en/services/tax/global-oil-and-gas-tax-guide---country-list. Generally, non-OPEC countries with mature fields and higher production costs (e.g. UK https://www.fool.com/investing/2017/03/19/you-wont-believe-what-saudi-arabias-oil-production.aspx) have lower overall government take. Adjustment of government take been a response of governments to maturing assets in order to prolong the productive life. A general discussion can be found at: https://siteresources.worldbank.org/INTOGMC/Resources/fiscal_systems_for_hydrocarbons.pdf.

It is essential when comparing fiscal costs also to compare technical costs.

- *Royalties*. Royalty regime modifications can make a significant impact on the positive decision to invest. Care needs to be take in State-Federal jurisdictions that any positive investment impact from a reduction in State royalties is not lessened by an increased Federal tax take. Example measures to reduce royalties (e.g. *for challenged resources* – see below) are:-
  - Simple royalty rate reductions, especially if focussed on the earliest production years.
  - Royalty holidays or deferments i.e. an early zero Royalty rate or a deferred royalty take to later in the production life.
  - Change of categorisation of 'allowable wellhead costs' which are subtracted from revenues prior to royalty calculations e.g. water related treatment costs in CSG fields.
- *Taxes*. Tax regime modifications can also make as significant impact.
  - Reduction of corporate (marginal) tax rates
  - Accelerated depreciation
  - Modifications to PRRT and ring fencing rules to allow losses (e.g. exploration costs) made outside the ring fence to be accumulated and/or offset against revenue from within it. See. Recent UK changes at: https://www.ashurst.com/en/news-and-insights/insights/energysource---issue-17---5---uk-north-sea-fiscal-regime/ - also see Norwegian rules on accumulation of losses to offset new plays.
  - Adjustment of tax rates in line with the 'attractiveness' of the resource-base e.g. a reduced marginal tax rate for certain classes of fields.
    - Areas can be declared 'mature' or 'frontier' and tax-royalties reduced accordingly
    - Pools (or possible remaining field reserves) may be declared 'small' or 'marginal' e.g. application of reduced marginal tax rates on small fields. Discussion on Malaysia and Nigeria and UK examples at https://www.palantirsolutions.com/incentivising-marginal-field-developments-part-2/

- Pools may be declared ‘tight’ or low rate and a gain attract different terms.
- Transferable tax credits that enable existing owners to sell mature assets (to lower cost operators) e.g. by allowing existing owners to pass on some of their tax history - https://www.offshoreenergytoday.com/north-sea-tax-review-good-news-for-offshore-sector/ . New, innovative companies can then bring new life to old assets.

B) Exploration Additions: Expected monetary value, EMV, is positive @ WACC given a ‘medium’ screening oil price.

EMV = Ps x NPVs – EFR;

where Ps = probability of success, NPVs = NPV of the success case discovery; and EFR = exploration funds at risk.

The equation for NPVs is as shown above in A) and all measures that improve NPV also improve EMV. In addition, a number of government actions can make more exploration decisions, EMV positive.

Measures related to probability of success, Ps.

- The maintenance of high quality, readily accessible geological data.
- The maintenance of high quality, play exploration history and well success-failure analyses.
- The identification, listing, stimulation and/or removal of long term, “fallow” discoveries from operators who have failed to develop them in X years (and/or coupled with a ‘small fields’ marginal tax rate) e.g. as in the UKNS “PILOT” program https://www.rigzone.com/news/oil_gas/a/10381/uk_dti_announces_the_5th_uk_fallow_assets_release/ e.g. https://www.ogj.com/articles/2001/10/seven-uk-north-sea-fallow-fields-considered-for-development.html
- Exploration risk can be reduced by extending licence terms, prior to relinquishment and by increasing the size of tenements: both maybe most applicable in the proving up of unconventional resources, though controls are needed (work programs) to prevent land banking.

Measures related to reducing Exploration Funds at Risk.

- Subsidies or partial subsidies to private companies for new data acquisition to of critical new data to be put into the public domain immediately– again *noting* that the type of data required to de-risk (improve Ps) for unconventional plays is more expensive than traditional forms of pre-competitive data (e.g. it may include.
- Incentivisation of new types of data acquisition e.g. seismic or wireline logging, through R&D tax credits (also may improve Ps, above)
- The application of R&D or similar tax credits to exploration spend (including the ability to offset exploration spend against previously ring fenced producing assets)
- The ability to accrue R&D tax credits and for small, non-revenue generating companies to pass these on to companies buying out an area.
- The extension for tax credits (especially in unconventional gas) to majority of unconventional gas pilot, appraisal program (e.g. spot pattern and hydraulic fracturing trials)
- Reduction of permitting cycle times is important both for bringing forward (discounting less) the success- case NPV as well as reducing risk.
- Reduction of compliance costs

END

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ATTACHMENT B – SELECT REFERENCES RELATING TO DOMESTIC RESERVATION

Year	reference	Extracts
2013	Deloitte Access Economics, 2013. The economic impacts of a domestic gas reservation. A report to the Australian Petroleum Production and Exploration Association. October 2013.	[p. ii] "The impact of a DGR is to – in effect – place a simultaneous tax on domestic gas production and subsidy on domestic gas consumption. Like all taxes and subsidies, the DGR distorts economic decisions and generates an unequivocal economic loss – one which compounds over time as future investment decisions are affected … the introduction of a DGR on the east coast is projected to cost the Australian economy $6 billion in forgone GDP at 2025 "
2013	King, S. (2013) 'A gas reservation scheme is protectionism in disguise', The Conversation, 30 January 2013, accessed 16 June 2013, from http://theconversation.com/a-gas-reservation-scheme-is-protectionismin-disguise-11810	"A gas reservation scheme is really a combination of an implicit "tax" on gas producers and a "subsidy" to domestic gas users … Of course, it is not really a tax because the money doesn't go to the government. Rather, the money goes to domestic gas users … I can think of many things the government could do with the money that it would raise from a tax on gas producers. Improving our schools, hospitals, roads and other infrastructure would be close to the top of my list. Subsidising domestic manufacturers to use more gas would not be on the list."
2013	Wood, T., Carter, L. and Mullerworth, D. 2013. Getting Gas Right: Australia's Energy Challenge, A presentation of the Grattan Institute.	[p17]. "Proponents who have argued for an east coast gas reservation frequently fail to acknowledge that policy implemented at this late stage of project development could significantly damage investors' confidence in the stability of Australian regulatory arrangements, and could deter investment."
2014	ERA, 2014. Inquiry into Microeconomic Reform in Western Australia: Final Report. Economic Regulation Authority, Perth.	The inquiry concluded "... the [domestic gas reservation] policy is likely to inhibit development of the Western Australian gas market in the long term" … and suggested to … "rescind the [domestic gas reservation] policy as soon as practicable"

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2014	BREE, 2014. Gas Market Report, Bureau of Resources and Energy Economics (BREE), November 2014, Canberra.	The Bureau of Resources and Energy Economics, Gas Market Report, November 2014 (which was also cited by the ACCC in 2016). BREE (2014) noted that "… higher domestic gas prices from linking to an export market are due to market dynamics and not a market failure. While there would be winners from a reservation policy, the gains to the winners (gas users) are unlikely to offset the direct economic losses to producers, and the broader economic losses that would arise over the longer term".
2015	Productivity Commission, 2015. Examining Barriers to More Efficient Gas Markets. Productivity Commission Research Paper. March 2015.	[p2] "…the integration of the eastern Australian gas market with the Asia–Pacific market represents an opportunity for the Australian community to earn a higher return from its substantial non-renewable resources. This will result in a net benefit to the community." [p 20-21] "The Commission's analysis and modelling indicate that a reservation policy would impose a cost on gas producers and ultimately on the broader community because it would divert the supply of gas from its highest value use, reflected in the higher prices prevailing in the Asia–Pacific. The cost to the community of diverting the gas from the export market to the eastern Australian gas market would outweigh any gains to domestic users, which are of themselves far from guaranteed… would reduce the return on, and create a disincentive for, investment in new supply sources."
2015	Simshauser, P. and Nelson, T. 2015. The Australian east coast gas supply cliff, Economic Analysis and Policy, Volume 45, 2015, Pages 69-88, ISSN 0313-5926	[p.84] " … introducing a domestic gas reservation policy. Our modelling indicates that such a policy is unlikely to be effective because the problem has to do with market fundamentals …. In our opinion, any policy designed to redirect 'forward contracted gas' (intended for LNG terminals) on a retrospective basis into the domestic market is likely to be unacceptable to policymakers due to the dynamic inconsistency problem that would subsequently arise. It would introduce sizable regulatory risks into an otherwise well-functioning industry facing transient supply/demand imbalances, which are best alleviated through alternative policy options such as facilitating greater supply." [p. 87] "Our advice to policymakers is therefore simple: with due regard to safety and environmental regulations, stabilise policy, and, facilitate supply-side expansion."

2016	ACCC, 2016. Inquiry into the east coast gas market. Australian Competition and Consumer Commission, April 2016. Canberra. ISBN 978 1 922145 77 2	The 2016 ACCC inquiry stated that gas supply "… would not be fixed by a reservation policy; in fact they could be worsened if a reservation policy was enacted which artificially depressed prices in the short term and discouraged investment in new gas supply, thus reducing the likelihood of required supply diversity … [and] … gas reservation policies should not be introduced, given their likely detrimental effect on already uncertain supply" (ACCC, 2016).
2016	ACIL ALLEN, 2016. Domgas Reservation Policy. Review of Literature and Policy	[p.28] "… the DGR policy is far from being the best policy to address inadequate capture of gas resource rent by Western Australians and to distribute it equitably and efficiently …": "the policy will reallocate resource rent from gas producers to gas users. but it is not obvious that Western Australians gas users are the most worthy recipients of the reallocated resource rents" and "… the DGR policy mechanism misallocates resources … adverse economic effects include some dissipation or destruction of resource rent to the detriment of Western Australians and foreign investors, through encouraging economically premature extraction and discouraging future exploration and consequent development activity"
2019	Neill K., Hartley P. and Tyers R. (2019). Western Australia's Domestic Gas Reservation Policy: Modelling the Economic Impact with a Computable General Equilibrium Approach. ECONOMIC RECORD, VOL. 95, NO. 308, MARCH, 2019, 90–113. doi: 10.1111/1475-4932.12459.	"… To examine the policy's effects, this paper employs a detailed model of the WA gas market that incorporates project-by-project supply, the very large fixed costs typical of gas supply projects, foreign ownership on both sides of the market and oligopolistic pricing power. This model … shows that the policy, as it has been applied to the Gorgon and Wheatstone projects, imposes an overall net loss to the nation of around $600 million each year. The net loss to Australian households is estimated to be $300 million. Moreover, no net long-run advantage is seen to be conferred on WA's workers or consuming households".