



# **Middle Arm Gas and Petrochemicals Hub: Combination of Problems Makes It Unprofitable for Business and a Red Flag to the Public**

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## Key Findings

**A plan to boost the Northern Territory's economy with a concentration of new industries at the Middle Arm Gas and Petrochemicals hub is a flawed concept.**

The Territory's plan to extract natural gas from the Beetaloo basin is based on fracking, which has proven to be a poor investment in other countries.

Given the obstacles, it is likely the costs of the project will fall on the people least likely to be able to afford it—Australian taxpayers.

The ambitious plan relies on too many unproven assumptions, including the viability of carbon capture and storage; a robust market for liquefied natural gas; partners who will agree to develop resources in the isolated region; and significant infusions of public dollars over a long period that could upset Australia's fiscal balances.



## Executive Summary

Spearheaded by the Department of Industry, Planning and Logistics (DIPL), the Northern Territory's industrial development plan promises a thriving network of industries including natural gas extraction, liquefied natural gas (LNG) exports, carbon capture and sequestration, mineral refining, advanced manufacturing, and the production of ammonia, urea, methane, ethylene and hydrogen. The goal is to generate an abundant supply of natural gas from the Beetaloo and Barossa gas fields to support LNG exports, domestic electricity needs, and an array of new (and existing) agrichemical and petrochemical companies.

The Middle Arm Sustainable Development Precinct plan, which promises new industry and substantial infrastructure investment, is flawed. Its market assumptions are overly optimistic; infrastructure needs will stress federal and local budgets; and the plan is misaligned with global efforts to curtail greenhouse gas emissions. The plans for exports, new technologies and new industries face a series of market, infrastructure and technological challenges. Because the Northern Territory is undeveloped, it would take a level of support that the combined balance sheets of Australia's federal government and several corporations cannot afford. A new supply of natural gas is not enough of a financial incentive to offset the costs of new agrichemical and petrochemical facilities, new roads, pipelines, ports, water systems, power plants, housing, schools and community facilities. The remote location puts the hub far away from businesses that can manufacture and service new product lines. The very real possibility exists that the plan will create fiscal imbalances between the states and territories, as well as budget pressures within the Northern Territory.

The business model underlying the plan is not viable. The development of the gas field relies on hydraulic fracturing (fracking) technology created in the United States. Fracking has been an economic failure even as it has produced an increase in oil and gas production. Investors have lost billions. It has also created water and land controversies resulting in civil penalties and criminal prosecutions. The companies leading the way in the Northern Territory – Santos, Tamboran and Empire Energy – each have strengths but are poorly positioned to take on these financial and logistical risks.

The plan also runs against Australia's climate strategies. The nation is committed to curbing its carbon emissions. This plan adds a new natural gas field, contradicting international plans to lower the world's greenhouse gas emissions. It also contradicts the many local and national climate solutions in which Australia – its people and businesses – is now engaged.

This report fundamentally looks at the financial risks to the redevelopment plan. Taken alone, any one of these risks is substantial but could be manageable. Cumulatively, these risks create a daunting set of problems that lower the potential for companies and investors to profit, and constitute a series of red flags to Australia's leadership. The infrastructure needs are vast, and the policy changes must be executed with a level of co-operation and co-ordination that would be extraordinary. Most of the business assumptions in the plan rest on either failed or unproven technological innovations. After rushing headlong with policy and public dollars, the NT government faces a risk that the markets will fail to produce the jobs and profits required to make the plan a success. The failure will be seen in the destruction of public promises and investor dollars.

This report provides an introductory overview that will be supplemented in the months ahead by more specific analytical treatment of critical issues and discussions of new information that emerges.

The risks we have identified are based on market, fiscal, governmental, and health and safety factors, viewed through a financial lens. They are organised around two basic headings: 1) The plan is flawed, and 2) The business model is not viable.

## The Plan Is Flawed

- **Risk 1:** The robust market for LNG exports anticipated in the plan is unlikely to materialise. Markets are changing, and Australia will be less able to compete on cost as its traditional customer base shrinks. This will undermine the financial success of the Beetaloo and Barossa gas investments.
- **Risk 2:** The off-taker industries anticipated to become partners (hydrogen, ammonia, urea, methane, carbon capture, advanced manufacturing and mineral processing) are unlikely to locate in the Northern Territory.
- **Risk 3:** Relying on carbon capture and sequestration (CCS) – a costly and unproven technology – to become a thriving industry and climate solution is unrealistic.
- **Risk 4:** Australia's domestic gas demand is likely to slow, and perhaps may even decline.
- **Risk 5:** DIPL's Middle Arm plan would strain the existing fiscal arrangement between the states and territories and the federal government in ways that are unsustainable.
- **Risk 6:** Government and corporate resources are not likely to be mobilised at sufficient levels and over the period necessary for the plan to be successful. Policy changes to address significant infrastructure issues in education, environment, transportation, water management and electricity regulation are too numerous to be practical.
- **Risk 7:** Natural gas industrial expansion conflicts with Australia's net-zero policy.

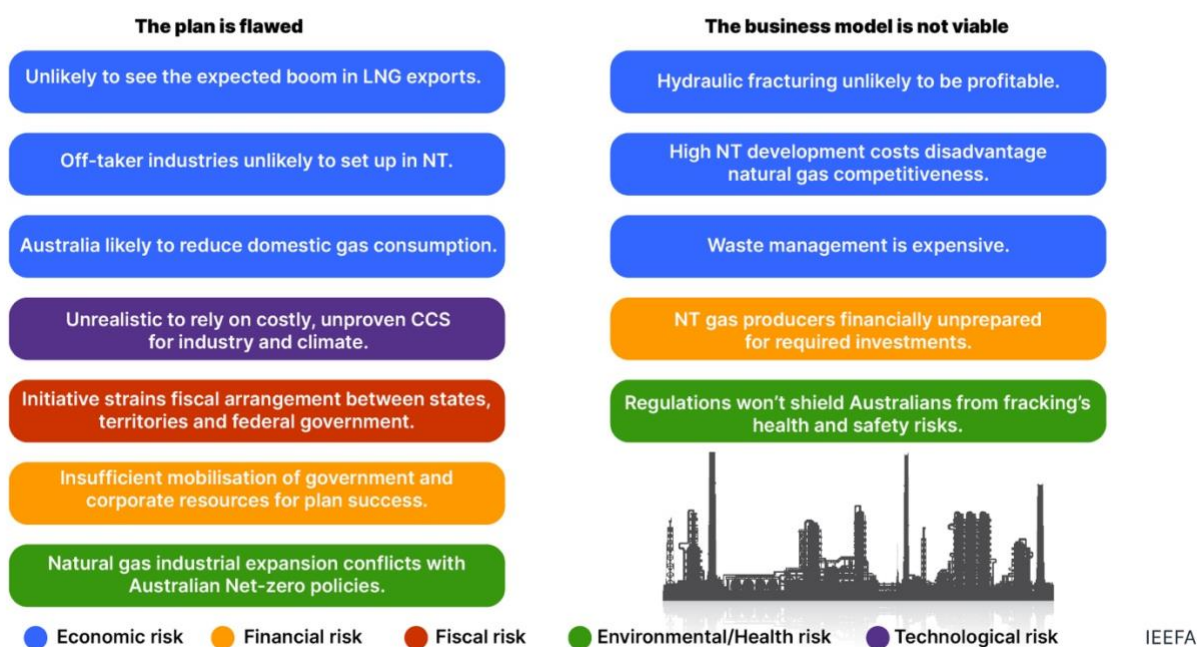
## The Business Model Is Not Viable

- **Risk 8:** The use of hydraulic fracturing is not likely to be profitable. Fracking has destroyed investor value over the long term in the U.S. With a weak business sector at its core, the off-taker industries do not have a stable partner to produce a reliable, cost-competitive supply of natural gas.
- **Risk 9:** Leading gas producers in the Northern Territory are financially unprepared to address the significant investments needed to explore, drill, distribute and support infrastructure to create a hub for LNG, agricultural and petrochemical development.
- **Risk 10:** Development costs in the Northern Territory for natural gas are high. Australia and the Northern Territory are at a competitive disadvantage against robust competition globally, and within Australia, for the gas market.

- **Risk 11:** Regulations are not likely to protect the Australian public against the health and safety risks of fracking. In the U.S., public health and safety mandates failed, and pollution of drinking water led to civil and criminal actions.
- **Risk 12:** The management of solid waste and wastewater is likely to be costly.

The fatal flaw of the Northern Territory development plan is its dependence on fossil fuels. Once the world's leading source of energy and financial growth, Australia now faces historically unprecedented competition. The plan is ambitious to the point of being prohibitively speculative. The risks will fall on the shoulders of the affected communities – who cannot afford to bear it – and Australia's taxpayers.

## Problems with the Middle Arm Gas and Petrochemicals Hub



## Introduction

At the core of the Northern Territory's plan, the Department of Industry, Planning and Logistics (DIPL) is seeking the approval for the Middle Arm Sustainable Development Precinct (MASDP) – a “development-ready”, precinct-wide program for the construction and operation of new industrial facilities with a focus on low-emission petrochemicals, renewable hydrogen, carbon capture and storage (CCS), and minerals processing.<sup>1</sup> At the centre of the strategy is the creation of an abundant supply of natural gas from the Barossa and Beetaloo fields that can be competitively sold on the LNG export market and used locally in industrial processes for businesses that would be drawn to the area.

The central planning premise of the project requires a number of economic and market factors to converge over a long period. The factors are outside the control of Australia and its partner companies. The convergences must maximise innovation, be timely and structured in a manner to allow participating companies to take advantage of domestic and global growth trajectories. The numerous planning studies and the public dialogues taking place, however, have unearthed many contradictions that government officials ignore at their peril.

The risks facing the project are individually substantial and cumulatively daunting. This report reviews several of the risks, focusing on financial aspects – the bottom line for companies and the core public benefits promised from a long-term redirection of federal and local budgets.

## Background

The Northern Territory (NT) government, through the DIPL, proposes to build and operate a new industrial precinct on the Middle Arm Peninsula at Darwin Harbour.<sup>2</sup>

The project would involve development of approximately 1,500 hectares of land on the Middle Arm Peninsula, including landside and marine enabling infrastructure. Activities proposed include the production of fertilisers, fuels, petrochemicals and refined mineral products. Traditional manufacturing operations based on extraction of natural resources represent most of the investment in the development, although some sustainable technologies, such as hydrogen made from renewable energy, are proposed. The proposal has been referred for assessment and approval under the Environment Protection and Biodiversity Conservation Act 1999 and NT Environment Protection Act (EP Act) 2019.<sup>3</sup>

<sup>1</sup> DIPL. [Middle Arm Sustainable Development Precinct Referral Report](#). January, 2022 (“MASDP Referral Report”), p. 1.

<sup>2</sup> The Northern Territory is part of the Australian federal structure. Parliament of Australia. [The Australian System of Government](#) (last visited June 7, 2023). Also see: ABC. [Why isn't the Northern Territory a State](#). February 17, 2023.

<sup>3</sup> [MASDP Referral Report](#), p. 1.

Figure 1: Schematic Overview of Northern Territory Development Plan—MASDP Map



Source: [Northern Territory Government, Department of Planning and Logistics](#).

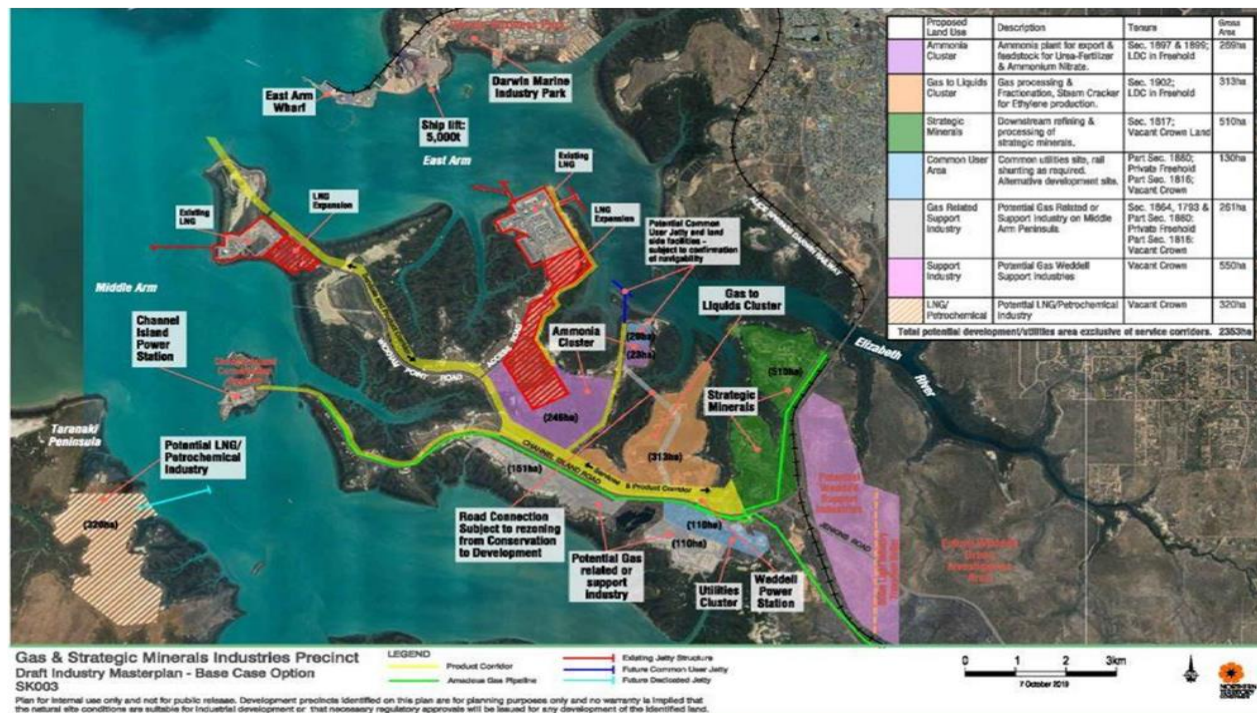
The economic development details behind the industrial precinct are contained in a series of reports released by the Territory Economic Reconstruction Commission (TERC), DIPL and supplemental analyses by various national, local, non-profit and local planning, market, fiscal and development studies.<sup>4</sup> Below is the list of industries that are targeted for the project. The map offers an initial sense of where the industries might be located within the precinct area.

- Liquefied Natural Gas (LNG)
- Ammonia and derivatives
- Urea and derivatives
- Ethylene and derivatives
- Methanol and derivatives
- Gas-to-liquids (GTL)
- Hydrogen
- Carbon capture and storage (CCS)
- Minerals processing
- Advanced manufacturing
- Support service industries

<sup>4</sup> TERC. [Territory Economic Reconstruction Commission Final Report](#), November 2020 (“TERC Report”).



Figure 2: Map of Potential Industries to Be Developed at the Middle Arm



Source: Northern Territory Government, Department of Infrastructure, Planning and Logistics. *Request for tender*. December 14, 2020.

The DIPL is leading the planning, design and approvals process. It has prepared a seven-part infrastructure plan to align with the new industrial development goals.<sup>5</sup> At the centre of the infrastructure effort will be:

- Creation of a Middle Arm Sustainable Development Precinct, a master plan that enables the industrial development outlined in the final TERC report;
- Darwin Regional Water Supply Infrastructure Program;<sup>6</sup>
- Infrastructure support to streamline residential and industrial development;
- Improvements in logistics and intermodal transportation;
- Road corridor enhancements;
- Development of the Beetaloo natural gas sub-basin, and;
- Infrastructure investment to support tourism.

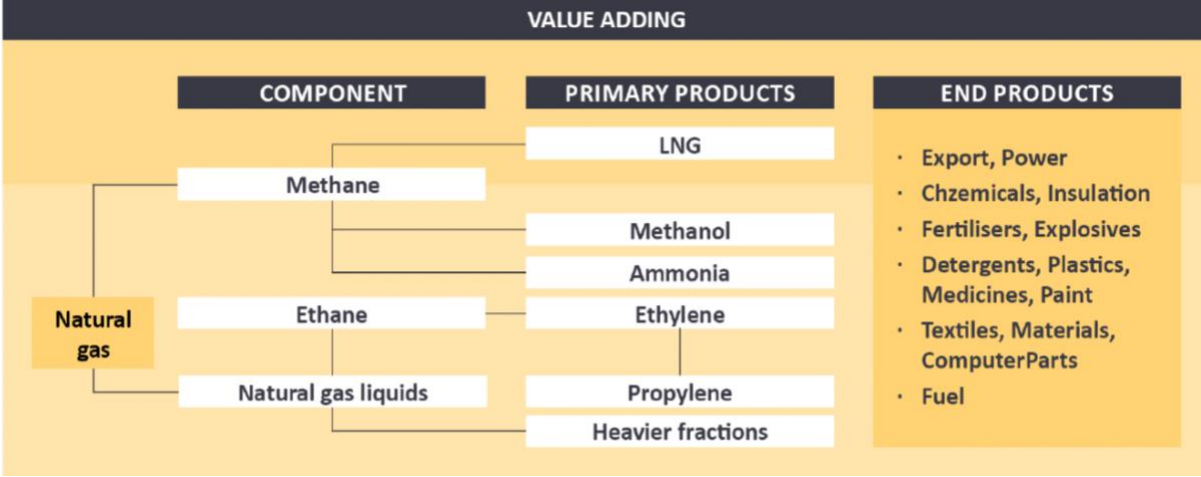
<sup>5</sup> Department of Infrastructure, Planning and Logistics. *NT Infrastructure Strategy 2022 to 2030*. June 2022.

<sup>6</sup> The Darwin Regional Water Supply Infrastructure Program is a plan to develop new water supply infrastructure to address growing water consumption needs. See Northern Territory Government. *Darwin Regional Water Supply Infrastructure Program*. (Last visited June 7, 2023.)

The ambitious plan seeks to bring a host of new businesses that capture growth trends in the world’s agricultural, petrochemical and newly emerging sustainable markets. New business development alignment with these trends will serve as the private capital catalyst that will shape substantial public infrastructure investments. The nexus of public and private finance is expected to create returns for both sides of the equation. The continuation of offshore gas development and scaling up of onshore natural gas assets are expected to provide an abundant and affordable feedstock for many new businesses. The plan for the Beetaloo to utilise unconventional natural gas production is critical for the overall success of the off-taker industries. A profitable, stable, sustainable, cost-competitive and reliable natural gas asset is fundamental if the project is to succeed. In addition to its direct market for domestic power production and LNG export, natural gas is used in production of ammonia, urea, ethylene, methanol and hydrogen. Most of the other industrial processes are likely to use natural gas for feedstock or energy.

The Beetaloo sub-basin is part of the onshore MacArthur Basin, and the Barossa offshore field is a proposed market backfill for the Bayu-Undan field. They are key to the economic plan. The two natural gas assets would be tapped to replace depleted natural gas resources, and to expand supply for industrial facilities and LNG supplies out of the Northern Territory. In particular, Northern Territory leaders are looking to capitalise on the untapped potential of the Beetaloo sub-basin.

Figure 3: Gas Value-Adding Chain



Source: TERC Report, p. 57.

The natural gas resource in the basin has been classified as unconventional shale gas. The gas has not formed conventionally as pools but is trapped in rock formations. To free the gas, a process known as hydraulic fracturing (fracking) is used. The process injects water at high pressure to split the rocks. The gas is freed and then travels to the surface through a well.<sup>7</sup>

Barossa is a gas and condensate field located in the Bonaparte Basin, off the coast of northern Australia, approximately 300 kilometres north of Darwin in the Northern Territory.<sup>8</sup> The field is

<sup>7</sup> See: Northern Territory. [The Scientific Inquiry into Hydraulic Fracturing in the Northern Territory](#), Chapter 6, March 2018 (“2018 Inquiry”) for a more complete description of the fracking process.

<sup>8</sup> Santos. [Barossa Gas Project](#).

operated by ConocoPhillips Australia Barossa, with SK E&S Australia and Santos Offshore as joint venture partners.<sup>9</sup>

The Barossa field was discovered in 2006, and is estimated to contain approximately 500 million barrels of oil equivalent (mboe) as recoverable resources, making it one of the largest undeveloped offshore gas resources in Australia.<sup>10</sup> The new field would replace the Bayu-Undan gas field.<sup>11</sup> The gas produced from the Barossa field is expected to be processed at the existing Darwin LNG facility, which is owned and operated by ConocoPhillips, to produce LNG for export. The offshore drilling and production activities associated with the Barossa field carry environmental risks, including potential oil spills, impacts on marine ecosystems, and other environmental concerns.<sup>12</sup>

Since December 2022, Santos has been under order by a federal court to stop drilling in the Barossa gas field, following a successful challenge from Indigenous groups.<sup>13</sup> Santos failed to meet legal requirements that require broad consultation with Indigenous organisations. The company has stated that it is making efforts to satisfy those legal requirements.<sup>14</sup> Since then, a broader set of actions spearheaded by clan leaders from the Tiwi Islands have resulted in a human rights complaint filed with 12 banks and three export-import credit agencies.<sup>15</sup> The complaint raises issues of irremediable harm that may require the banks and/or credit agencies to exit their financial commitments under various international human rights pacts.

## The Rationale Behind the Project

The NT government expects the overall development plan will support the delivery of a \$40 billion economy by 2030, up from a current gross state product (GSP) of \$26 billion while meeting net-zero emissions commitments by 2050.<sup>16,17</sup> Each phase of the development is designed to increase employment, first in the construction business related to infrastructure and business development, and then in long-term employment in the new industries. At its most ambitious, planners project an additional 34,000 jobs.<sup>18</sup>

The project envisions a master-planned precinct with a focus on low-emission hydrocarbons, green hydrogen, advanced manufacturing, CCS and minerals processing. The DIPL asserts that sustainable outcomes and environmental protection of Darwin Harbour and the Middle Arm precinct are at the core of the plan.<sup>19</sup>

<sup>9</sup> Offshore Technology. [Barossa Offshore Development Project](#). September 28, 2018.

<sup>10</sup> Offshore Technology. [Barossa Conventional Gas Field, Australia](#). November 22, 2021.

<sup>11</sup> National Offshore Petroleum Safety and Environmental Management Authority. [Project – Barossa Area Development](#). (Last visited June 7, 2023).

<sup>12</sup> ABC. [South Korean financier pauses loan for multi-billion dollar Barossa gas project](#). April 19, 2022.

<sup>13</sup> [Santos NA Barossa Pty Ltd v. Tipakalippa](#) [2022] FCAFC 193 (Appeal Decision).

<sup>14</sup> Santos. [Response to Equity Generation Lawyers Letter](#). May 2023.

<sup>15</sup> Equity Generation Lawyers. [Human Rights: Bank Grievances](#). Human Rights Bank. (Last visited June 6, 2023).

<sup>16</sup> All dollar values are in Australian currency unless otherwise noted.

<sup>17</sup> [TERC Report](#), p. 2.

<sup>18</sup> [Ibid.](#)

<sup>19</sup> Northern Territory Department of Infrastructure, Planning and Logistics. [Middle Arm Sustainable Development Precinct](#). September 13, 2022, p. 1.

The operational aspects of the overall plan require careful co-ordination of a rebuilt infrastructure and attraction of outside investors. A major projects commissioner will serve as the single point of co-ordination for major project investment.<sup>20</sup>

The plan proposes a “step change” in government/business co-operation, which would include a complete overhaul of existing policies related to land, water, energy, telecommunications and logistics (roads, schools, housing, education), as well as the regulatory systems that support them.<sup>21</sup>

Guided by TERC’s final report released in November 2020, the NT government seeks to transform Middle Arm into an industrial precinct. It hopes to capitalise on the untapped potential of the Beetaloo field and success of the Barossa field. The Beetaloo covers an area of approximately 28,000 square kilometres south-east of Katherine and east of Daly Waters. The sparsely populated Beetaloo sub-basin is a relatively underexplored onshore area considered part of the McArthur Basin.<sup>22</sup> The government aims to capitalise on the territory’s access to natural gas to increase manufacturing and jobs while supporting economic growth.

## Government Funding and Private Investment Commitments

There have been a number of budget announcements in support of various parts of the Middle Arm project. In early 2022, then National Party leader and Deputy Prime Minister Barnaby Joyce announced the federal government would provide \$2.6 billion to support Middle Arm.<sup>23</sup> Upon the return to power of the Labor government, the budget status – the size of the allocation and purpose – appears to have changed.

The budgetary changes resulted in a \$1.9 billion package to dredge the harbour, upgrade wharves and provide regional logistics.<sup>24</sup> The *Australian Financial Review* now characterises the funding as “off-budget,” leaving a level of uncertainty for the schedule of the projects, source of the funding (debt or operating resources) and future budget prioritisation.<sup>25</sup>

The new package also came with a policy realignment regarding CCS. The new Labor program pushed back funding commitments for CCS and narrowed policy focus to “hard-to-abate” industrial applications. Recent commentary on CCS suggests the need to develop a regulatory framework, a project prioritisation road map and incentives before the technology is widely used.<sup>26</sup>

The federal and NT governments have a general working agreement to support efforts to achieve the broad goals of the plan and the initial \$1.9 billion commitment.<sup>27</sup> The specific policy decisions are in

<sup>20</sup> [TERC Report](#), p. 33.

<sup>21</sup> [TERC Report](#), pp. 24-25.

<sup>22</sup> [2018 Inquiry](#), p. 84.

<sup>23</sup> National Party of Australia. [2022-23 Budget delivers \\$7.1 billion to turbocharge our regions](#). March 29, 2022.

<sup>24</sup> The most recent Northern Territory budget released in May 2023 acknowledges the \$1.9 billion but does not count it in the budget until it has finalized its expenditure plans with the federal government. Northern Territory. [Budget 2023. Budget Paper No. 2: Budget Strategy and Outlook](#). May 2022, p. 61.

<sup>25</sup> Australian Financial Review. [‘Off budget’ spending expanded for Northern Territory energy hub](#). February 2023.

<sup>26</sup> S&P Global. [Australia can become CCS powerhouse, but some hurdles linger](#). May 23, 2023 (“S&P Global CCS”).

<sup>27</sup> Madeleine King. [Budget 2023-24: Budget promotes energy security and low-carbon future](#). May 9, 2023.

the process of being settled. A recent Senate inquiry into the Beetaloo development concluded with a list of 14 recommendations designed to shape the future development.<sup>28</sup>

The extent of any private investment as part of an integrated public-private co-ordinated strategy has not been disclosed. Private investment plans are largely contained in corporate disclosures, usually related to the various permitting and exploration activities under way by individual companies. Tivan, for example, has announced the relocation of its headquarters in the Northern Territory. Tivan is a minerals processing company seeking to improve its positioning as a critical player in the minerals market that supports renewable energy.<sup>29</sup>

The potential of the Beetaloo Basin has attracted interest from several oil and gas companies, including Tamboran,<sup>30</sup> Falcon,<sup>31</sup> Santos,<sup>32</sup> Origin Energy<sup>33</sup> and Empire Energy.<sup>34</sup> Work was previously undertaken by a Rio Tinto Group subsidiary, Sweetpea Petroleum, Hess Australia and Falcon Australia.<sup>35</sup> Sweetpea drilled the Shenandoah-1 vertical well, which was deepened by Falcon Australia. Hess acquired 3,490km of 2-D seismic data, to date the largest onshore 2-D seismic program in Australia. Based on the seismic database,<sup>36</sup> existing well data and modeling, Falcon Australia concluded that the Beetaloo Basin was an active petroleum system.<sup>37</sup> Origin Energy has sold its interests.

Although ongoing exploration and drilling activities have led to estimates of significant shale gas resources in the basin,<sup>38</sup> no large-scale commercial production has yet been established.

## Status of Development and Decision-making

Planners have completed layout proposals, conducted concept engineering analyses, environmental studies and analyses, and identified a location for the wharf and module offtake facility. In conjunction with the Department of Chief Minister and Cabinet (DCMC), the MASDP has received outline facility development proposals from a number of proponents, and conducted workshops on wharf location and other issues.<sup>39</sup>

<sup>28</sup> The Senate, 46<sup>th</sup> Parliament of Australia. [Oil and gas exploration and production in the Beetaloo](#). April 2023.

<sup>29</sup> Mining. [Tivan HQ relocates to Darwin](#). April 2023.

<sup>30</sup> Oil and Gas Journal. [Tamboran pursuing potential 5-tcf 2p Beetaloo reserves](#). November 23, 2022. Tamboran is currently the lead company in the Beetaloo, as it controls four permits and is moving forward with testing and assembling the technology necessary to start production.

<sup>31</sup> Falcon Oil and Gas. [Beetaloo Sub-Basin, Australia](#). Last visited June 8, 2023.

<sup>32</sup> Oil and Gas Journal. [Santos-Tamboran JV increases Beetaloo contingent gas resources by 164%](#). September 6, 2022.

<sup>33</sup> Although Origin took an initial position in the Beetaloo, it later sold its interests at a loss to Tamboran. Origin said its reason for pulling out was related to changing corporate priorities and noted the length of the appraisal and exploration process. Origin Energy. [Origin to divest Beetaloo basin interests, intends to exit upstream exploration permits](#). September 19, 2022. Also see: Origin Energy. [Origin completes sale of Beetaloo interest](#). November 9, 2022.

<sup>34</sup> Empire Energy. [Empire targets Beetaloo Sub-Basin](#). September 2022. Also see: Empire Energy. [Beetaloo Operations Update](#). September 12, 2022.

<sup>35</sup> Protect Country Alliance. [The Beetaloo Sub-basin: Communities and environment under threat](#). (Last visited June 7, 2023.)

<sup>36</sup> GEMIS. [Beetaloo 2D Seismic Survey](#). 2013. 2D seismic data is a technical term for a cross-sectional depiction of subsurface conditions used to analyze probability of oil and gas resources.

<sup>37</sup> Falcon Oil & Gas (Falcon Australia). [Beetaloo Sub-Basin, Australia](#). (Last visited June 7, 2023.)

<sup>38</sup> [2018 Inquiry](#), p.46.

<sup>39</sup> Northern Territory. [Request for Tender](#). December 14, 2020.

The next step is producing an environmental impact assessment (EIA) for the project, and submitting it to the Environmental Impact Authority. The EIA must assess the impact of implementing the project on environmental factors, including matters of national environmental significance (MNES), evaluate the acceptability of impacts, and identify the extent to which negative impacts can be avoided.

Based on the EIA and public input, the Environmental Impact Authority makes a recommendation to the environment minister whether the project should proceed, proceed with modifications, or not proceed.<sup>40</sup> The DIPL expects to obtain environmental approval for the project in 2025, and to obtain permit approvals to begin construction in 2026.<sup>41</sup>

This IEEFA report examines the domestic and global market conditions relevant to the long-term economic development project, and discusses key issues that will shape the direction of economic activity.

The remainder of this report analyses the financial risks facing the project. The risk factors are divided into two broad categories – one related to the development plan; the other to the business model underlying the plan. This report is meant to serve as an overview of risk factors analysed at a time when the project is at the beginning stages. Regulatory proceedings, public budget initiatives, company plans and market shifts will change and necessarily alter the risk profile of the program. IEEFA anticipates additional analyses that document those changes.

## I. The Development Plan for Middle Arm Is Flawed

The development plan for Middle Arm is flawed. Its market assumptions are overly optimistic; infrastructure needs are substantial, requiring policy and finance decisions that will place stress on federal and local budgets; and the plan is misaligned with global efforts to curtail greenhouse gas (GHG) emissions.

The DIPL plan is designed to create an investment environment to expand existing companies and attract new ones. Each industry has its own story and position within the global economic order. A closer look at some of those industries (LNG, hydrogen and carbon capture) and how businesses are positioned to launch new facilities in the Northern Territory is not promising. The plan also assumes robust domestic demand for natural gas, even as a number of factors suggest the market will not grow at rates sufficient to support new supply assets.

The plan is also based on unrealistic policy and financial assumptions. Successful development will require a host of major policy changes over a long period of time that must occur in a co-ordinated manner with private, federal and local support. Most of the required policy changes will rely upon substantial public commitments over a long period. The fiscal stress on local and federal government resources is a major risk factor.

Finally, the overall plan largely depends on the development of a new gas field and the use of CCS to manage industrial emissions. The plan is misaligned with the goals of the 2015 Paris Accord.

<sup>40</sup> Environmental Protection Act 1986. Also see: EPA. [Environmental Impact Assessment \(Part IV Divisions 1 and 2\) Administrative Procedures](#). Also see: EPA. [Step-by-step through the proposal assessment process](#). (Last visited June 7, 2023.)

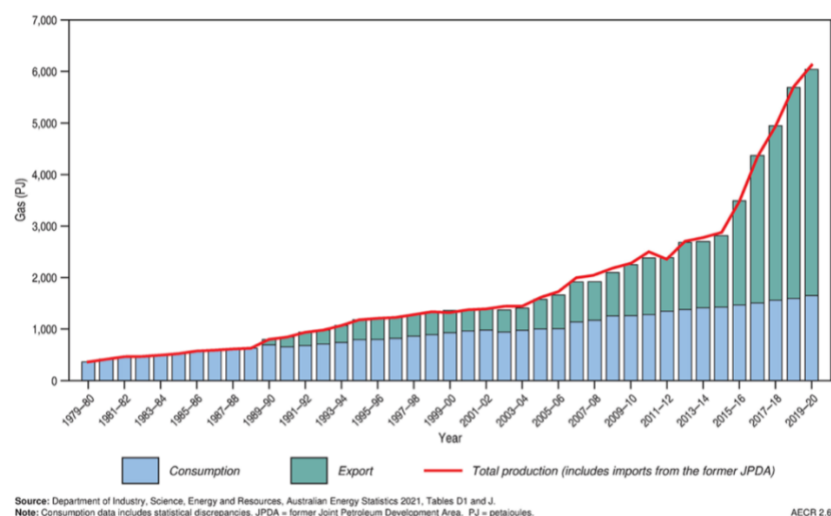
<sup>41</sup> Department of Infrastructure, Planning and Logistics. [Project overview](#). September 2022, p. 4.

According to the International Energy Agency (IEA), new gas fields are not needed if the world is going to meet its emissions targets of limiting global warming to 1.5°C by 2050.

***Risk 1: The robust market for LNG exports anticipated in the plan is unlikely to materialise. Markets are changing, and Australia will be less able to compete on cost as its traditional customer base shrinks. This will undermine the profitability of both the Barossa and Beetaloo investments.***

Although consumption of natural gas production in Australia grew from 2010 to 2020 at a rate of 17% annually,<sup>42</sup> it is not likely to continue increasing.

**Figure 4: Total Consumption of Natural Gas, Domestic and Exported (1979-2020)**



Source: Australian Government. [Gas](#). Last visited June 7, 2023.

LNG exports have driven much of the increased consumption of Australia natural gas. Fully 68% of the natural gas produced in Australia is exported (3.75 trillion cubic feet of 5.49 Tcf) (Table 3),<sup>43</sup> primarily to China, Japan, South Korea and Taiwan.<sup>44</sup> LNG is the third-largest export from Australia.<sup>45</sup> The country is the world's leading exporter of LNG, posting a volume of 3,874 petajoules (PJ) and capturing 21.8% of the global market.<sup>46</sup>

Conditions, however, are changing and eroding market fundamentals that once favored Australia.

Australia's position as a leading exporter of LNG is at risk from a cumulative set of structural factors leading to decreased demand from major importers and an inability to compete on cost.<sup>47</sup>

<sup>42</sup> Australian Government. [Gas](#). Last visited June 7, 2023.

<sup>43</sup> Upstream. [Australia's LNG exporters might need to divert volumes to domestic market](#). March 17, 2023.

<sup>44</sup> Australian Government. [Gas](#).

<sup>45</sup> Australian Government. [Australia's Top 25 Exports, Goods & Services](#). January 2020.

<sup>46</sup> International Energy Agency. [LNG exports for selected countries, 2015-2025](#). October 26, 2022.

<sup>47</sup> Upstream. [Australia remains world top LNG exporter but it could lose its crown this year](#). January 19, 2022.

LNG exporting plays a pivotal role in the successful development of the plan. LNG demand is essential for the success of the Barossa field since it would backfill customers supported by the Bayu-Undan field. Together with the Beetaloo field, they serve as an anchor for the Northern Territory's resurgence, maintaining existing customers and acting as a catalyst for early developers with a substantial risk appetite and eventually as a stabilising factor to attract additional investment.

The plans to move forward with exploration and production of the new gas field assume that time is of the essence.<sup>48</sup> It's been estimated that companies could move into production in late 2023, but some operational dates have been pushed back to 2025.<sup>49</sup>

The final TERC report acknowledged the pivotal importance of LNG to the success of the entire economic development enterprise:

“Currently generating in exports more than a fifth of the Territory's Gross State Product, this industry has the capacity to grow, the timing of which depends on domestic and international demand and the development of new prospective sources of onshore gas resources and existing offshore gas reserves.

In the absence of local demand, large scale gas projects remain export focused, looking to meet demand in markets outside the Territory. This means that supplies can be commercialised before local demand is ready.

“To secure gas feedstock for businesses in the Territory it is critical to build local demand and to create options to take advantage of gas supplies into the future as new business are created”.<sup>50</sup>

There are four principal reasons to conclude that the robust market for LNG anticipated by TERC will not materialise.

First, the markets will be saturated with new LNG supply capacity through 2027. The largest contributor to the Asian market will be Qatar, which has several new projects coming online in 2026 and 2027. (See Appendix II)

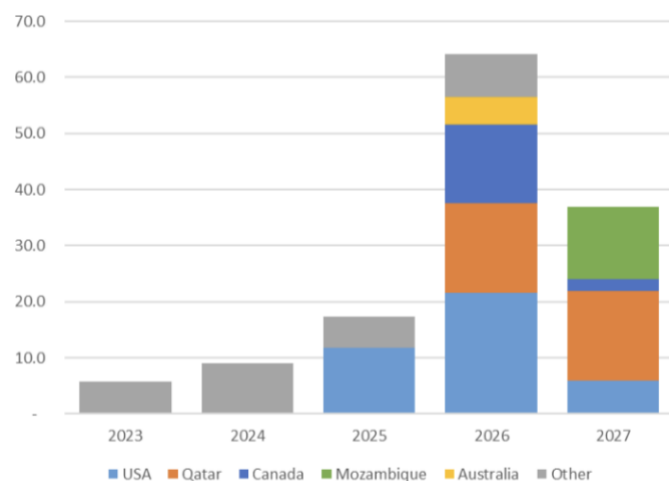
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<sup>48</sup> [TERC Report](#), p. 25.

<sup>49</sup> [Ibid](#), p. 55, 62, 67 and 93.

<sup>50</sup> [Ibid](#), p. 46.



**Figure 5: Global LNG Capacity Additions Through 2027**

Source: IEEFA, IHS Markit, and International Gas Union.

Australia's contributions to global LNG supply will be relatively small in the aggregate. As noted in Figure 5 above, Qatar gas has historically had a substantially lower breakeven price than Australia. (See Figure 6: Global LNG Cost Curve).

Second, Australia's natural gas cost structure puts it at a competitive disadvantage to some of the world's leading supplier companies and countries, as explained in a Qenos study submitted to the Australian Competition and Consumer Commission (ACCC) LNG Netback Price Series Review in 2021.<sup>51</sup> Figure 6 highlights the higher cost disadvantage the major LNG producers face in Australia. The figure demonstrates higher-than-average liquefaction and upstream costs for the mainstream production assets that place Australia's future at risk as the No. 1 LNG provider. As noted above, the initial findings at Beetaloo do not offer evidence that will alter the competitive cost structure.<sup>52</sup>

<sup>51</sup> Qenos, Orica and Incitec Pivot Limited. [Appendix – Submission to ACCC LNG Netback Price Series Review](#). May 2021, p. 17.

<sup>52</sup> Empire Energy has reported that recent results show the natural gas from its wells has fewer impurities than originally expected. How this plays out in the total cost structure is important but unlikely to prove decisive in improving Australia's position. See: Empire Energy. [Beetaloo Operations Update](#). September 2022.

**Figure 6: Global LNG Cost Curve - Australia's Competitive Complications**

Source: S&P Global.

Third, the supply growth identified above is affecting forward pricing indexes. The Japan Korea Marker (JKM) futures curve has declined from \$20 per million metric British thermal units (mmbtu) in winter of 2023 to a low of \$8.20 in August 2028.<sup>53</sup> The Territory's plan aims to secure major new projects by 2030, but gas fields opening now through 2028 face a tough pricing environment. With projects looking at \$9 breakeven prices, the futures market is not promising for new investments entering the market in the near and medium term.

Fourth, Australia's chief export partners – China, Japan and South Korea – are expected to slow or reduce LNG imports. The IEA's China outlook estimates that LNG growth, which was 12% (compound annual growth rate, or CAGR) from 2010 to 2021, will slow to 2% for most of the next decade. China has contracted long term for substantial volumes, and has initiated new domestic projects and increased its reliance on pipelines. The IEA estimates that the contracts and new projects more than cover China's demand requirements through 2035.<sup>54</sup>

***Risk 2: The off-taker industries anticipated to become partners (hydrogen, ammonia, urea, methane, carbon capture, mineral processing and advanced manufacturing) are unlikely to locate in the Northern Territory.***

The off-taker industries – such as LNG, ammonia, urea, methanol, ethylene, hydrogen, carbon capture, mineral processing and advanced manufacturing – anticipated by the commission to become partners in the plan are unlikely to locate in the Northern Territory. The hydrogen industry particularly is expected to play a pivotal role. But the Territory faces domestic and international factors that undermine its competitive position.

The Beetaloo gas field is to serve as a source of feedstock and possible electricity demand for a host of new industries. Some of the expected industries have roots in the Northern Territory, and others are anticipated to be drawn by the prospect of abundant feedstock from natural gas. Industrial

<sup>53</sup> CME Group. [LNG Japan/Korea Marker \(Platts\) Futures](#). April 11, 2023.

<sup>54</sup> International Energy Agency. [Outlook for gaseous fuels](#). October 2022.

infrastructure and abundant natural gas are expected to service the ammonia, urea, methanol and ethylene businesses, as well as minerals processing.

The TERC report presumes the development of a robust hydrogen industry.<sup>55</sup> The opportunity is linked to Australia's broader plans as the country seeks to align its internal domestic economy with the economic growth priorities of other nations. Half of Australia's trading partners have made net-zero commitments, and the figure is likely to increase. At the centre of many of these proposals is the development of hydrogen hubs. Japan, South Korea and China have all announced plans to use hydrogen as a central component of their economic decarbonisation plans.

While the overall goal is to develop green hydrogen, "blue" hydrogen made with natural gas is seen as a stepping stone to an economy based on cleaner fuels. Used as feedstock for hydrogen production, natural gas would be an anchor for a newly minted Beetaloo gas field.<sup>56</sup>

The proximity to natural gas fields is key to the development of hydrogen production, given the dominance of the blue hydrogen option in the current economic environment. The problem for the Northern Territory is that the Australian government has already set out a strategic vision for hydrogen production nationwide, which does not include the Northern Territory as a priority.<sup>57</sup> The existence of an abundant supply of natural gas is not the only criteria required to select the area as a priority for CCS hydrogen investment. According to its Department of Climate Change, Energy, the Environment and Water (DCCEEW):

The best areas for CCS hydrogen production would be close to coal or gas sources and to subsurface storage for carbon dioxide. Geoscience Australia has identified Australia's most prospective areas, considering these two requirements along with pipeline access and availability of water (in this case, not limited to desalination). Figure 1.8 shows these areas. In the near term, the best CCS opportunities are in the Carnarvon Basin; offshore Western Australia (the site of one of the world's largest carbon capture and storage projects on Barrow Island); in the Gippsland Basin, in offshore Victoria (site of the CarbonNet project); and onshore regions near the Cooper Basin (Queensland and South Australia), and Surat Basin (Queensland).<sup>58</sup>

The factors driving this selection process favour sites close to gas and coal seams, subsurface storage, pipelines and water. The sub-basins that scored higher than Beetaloo have a higher suitability rating, and are more likely to receive both governmental support and private sector investment.

The importance of the rating by the plan cannot be underestimated. The development of a gas field and the creation of a hub, particularly one dependent on carbon capture technology, requires a permanent commitment of government policy and financial support.<sup>59</sup>

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<sup>55</sup> [TERC Report](#), p. 43.

<sup>56</sup> *Ibid.*

<sup>57</sup> Department of Climate Change, Energy, the Environment and Water (DCCEEW). [Australia's Hydrogen Strategy](#). 2019 ("Hydrogen Study").

<sup>58</sup> [Hydrogen Study](#), p. 13.

<sup>59</sup> M. Bui, *et al.* [Carbon Capture and Sequestration: The way forward](#). *Energy & Environmental Science* 11:1062-1175. 2018. The government's recent decision (see Budget Discussion above) to slow the development of CCS has important implications for all of the industries, like hydrogen, that would need a reliable technology that is cost effective.

All levels of government will need to be judicious in its selection to ensure that its initial investment is a success not only in the eyes of Australian citizens but also in the view of global business interests.

***Risk 3: Relying on CCS—a costly and unproven technology—to become a thriving industry and climate solution is unrealistic.***

Carbon capture and sequestration (CCS) is unproven as a financial proposition, and technologically is being debated on performance grounds. Despite decades of research and demonstration projects, the resolution of these issues may be a decade away.

Recent commentary on the status of carbon capture in Australia has identified several hurdles facing the technology's development and broad application.<sup>60</sup> Australia lacks a regulatory framework for the development and use of CCS. The technology has historically been applied to enhanced oil recovery (EOR) to increase production. More ambitious plans support the application of CCS to most of the industries being proposed in the industrial development plan. Stakeholders have also discussed the need for a road map, or a system that allows the country to prioritise projects. Despite widespread optimism in industry and government about CCS, however, it is telling that Santos – which has emphasised the significance of CCS for facilities such as the Moomba project in South Australia, billed as the largest CCS project in the world – is moving forward but faces broad investor concerns.<sup>61</sup> Finally, there is no consensus for subsidising the projects.<sup>62</sup>

The Northern Territory is an economically underdeveloped area. As such, its emissions profile has been minimal. As any new development is planned, careful consideration needs to be given to the changing emissions profile. Net zero commitments by Australia and other regions are opportunities for the Territory to seek linkages with countries that have net zero commitments.

The final commission report addresses the broader decarbonisation question with four broad strategic directions: Research and development, global shipment of lower-emitting natural gas, carbon offsets, and carbon capture and sequestration. The wide application of CCS is important to the plan. Its success means a new industry is possible and its adoption by off-taker industries mean emissions reduction and new economic development can be achieved.

The Northern Territory plan acknowledges that CCS is in the test phases of potential commercialisation. There are potential applications of the technology to coal and natural gas plants and broader industrial uses – for example, in the development of the hydrogen industry.<sup>63</sup> CCS is

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<sup>60</sup> IEEFA has created a small library of articles reviewing the prospects for hydrogen around the world. See: IEEFA. [Energy Department should only spend public funds on hydrogen hub projects that are practicable](#). April 07, 2023. Also see: IEEFA. [No “traditional” coal mining at Wandoan but Glencore investors will still have concerns over coal emissions](#). April 04, 2023. Also see: IEEFA. [Opportunities and challenges for the Pilbara amid the accelerating steel technology transition](#). March 27, 2023. Also see: IEEFA. [The Energy Department's hydrogen gamble: Putting the cart before the horse](#). February 28, 2023. Also see: IEEFA. [From intent to action: India well poised to become a global leader in green hydrogen](#). January 11, 2022. Also see: IEEFA. [India's G20 presidency is an opportunity for green hydrogen leadership](#). December 22, 2022. Also see: IEEFA. [MENA, a potential new hub for green steel and green iron metalics](#). December 08, 2022. Also see: IEEFA. [A gas pipeline in disguise? Known unknowns about H2Med](#). December 08, 2022. Also see: IEEFA. [Fact Sheet: Blue Hydrogen in the UK](#). September 14, 2022. Also see: IEEFA. [India must act fast to avoid trailing in the global race for green hydrogen](#). September 1, 2022. Also see: IEEFA. [The race for new-generation clean energy technologies in India](#). July 11, 2022. Also see: IEEFA. [Investing in clean energy can help insulate India's fertiliser sector from global risks](#). July 5, 2022.

<sup>61</sup> NS Energy. [Moomba Carbon Capture and Storage CCS Project](#). (Last visited June 1, 2023.)

<sup>62</sup> S&P Global CCS.

<sup>63</sup> TERC Report, p. 43. Also see: Australian Government. [Australia's National Hydrogen Strategy](#). 2019.

seen as a potential emissions-reducing technology for most of the new industries planned (ammonia, urea, hydrogen, methanol) as a method to enable broader use of natural gas in Australia and to increase the country's export base.<sup>64</sup>

Despite decades of investment in CCS, the technology is not investable.<sup>65</sup> Empirical studies of major projects with global recognition, including one with a 40-year history of operations, show the technology has consistently failed to meet expectations.<sup>66</sup>

There also remains a debate over the proper metrics to measure CCS success. Downstream methane leakage, for example, is excluded from the universe of capturable emissions.<sup>67</sup> Studies consequently focus on standalone measures of the technology's efficiency but do not include the full array of emissions that occur downstream.

The application of carbon capture to coal-fired power plants in the U.S. has a history of extraordinary failure.<sup>68</sup> These efforts have failed because the technology is expensive and does not meet required emissions reductions standards.<sup>69</sup> The practical problems that caused carbon capture projects at coal power plants to fail in the late 1990s and early 2000s have not been corrected.

A 2008 audit by the U.S. Government Accountability Office (GAO) on CCS projects noted that few were under way at the time. With only a few demonstration projects on coal-fired power plants, active commercial viability was still more than a decade away.<sup>70</sup> A December 2021 GAO audit chronicled a series of failed demonstration projects from a program portfolio of 11 projects. The audit concluded that **projects continued to struggle to meet performance goals** and lessons learned from past failures had not been applied. The report warned against a repeat of this historical pattern of lax oversight and strongly cautioned against the use of more taxpayer dollars without recognition of the lessons learned.<sup>71</sup>

Problems with CCS technology are not limited to the U.S. One project demonstrates the point: An ethylene cracker proposed in Antwerp, Belgium (Project ONE), has selected CCS as a potential emissions reduction technology for its new plant. There are 38 existing crackers in the European Union. The carbon efficiency creates 0.81 tonnes of CO<sub>2</sub> for every tonne of high-value chemical (principally ethylene); the EU has adopted a standard that requires existing crackers to reduce emissions efficiency to 0.62 tonnes of CO<sub>2</sub> for every tonne of high-value chemical.

Project ONE produces 0.26 tonnes of CO<sub>2</sub> per tonne of high-value chemical. It achieves these relatively low CO<sub>2</sub> levels because it uses U.S. ethane (most European crackers use heavy oil

<sup>64</sup> TERC Report, p. 43.

<sup>65</sup> IEEFA. [Carbon capture landscape 2022—still too early confidently fulfill promises](#). July 2022. Also see: IEEFA. [Carbon capture has a long history. Of failure](#). September 2, 2022.

<sup>66</sup> IEEFA. [The ill-fated Petra Nova CCS project: NRG Energy throws in the towel](#). October 5, 2022. Also see: IEEFA. [Shute Creek World's Largest Carbon Capture facility sells CO2 oil production, but vents unsold](#), March 2022. Also see: IEEFA. [Gorgon carbon capture and storage: The sting is in the tail](#). April 29, 2022.

<sup>67</sup> IEEFA. [Infographic: Carbon capture's methane problem](#). August 11, 2022.

<sup>68</sup> IEEFA. [Kemper IGCC Project: Cost and Schedule Risks](#). November 19, 2012. Also see: IEEFA. [Kemper Power Plant, a Debacle That Should Never Have Been](#). November 20, 2014.

<sup>69</sup> IEEFA. [Keep San Juan power plant shut down](#). November 7, 2022.

<sup>70</sup> U.S. Government Accountability Office. [Climate Change: Federal Actions Will Greatly Affect the Viability of Carbon Capture and Storage As a Key Mitigation Option](#). September 30, 2008, p. 34.

<sup>71</sup> U.S. Government Accountability Office. [Carbon Capture and Storage: Actions Needed to Improve DOE Management of Demonstration Projects](#). December 2021.

naphtha), uses wind power under a power purchase agreement (PPA), and increasingly replaces natural gas with a mix of natural gas and hydrogen for its internal heating and production sources.

If the developer INEOS receives EU approval and adopts the technology and if the technology works, this will drive the carbon efficiency ranking and standard in the EU to .4 tonnes of CO<sub>2</sub> per tonne of high-value chemical.

The goal of INEOS's PROJECT ONE is a completely carbon-neutral cracker. CCS is being considered to manage the remaining 0.26 tonnes of CO<sub>2</sub>. INEOS has identified the planned CCS method using monoethanolamine (MEA).<sup>72</sup>

INEOS concluded:

“The above analysis of the CO<sub>2</sub> capture installation using the current state of the art technology based on MEA absorption, shows that this technology has a large steam demand that significantly increases the natural gas consumption of the steam boilers and also means an additional electricity and cooling demand. CO<sub>2</sub> capture represents a significant reduction of approximately 74% compared to the CO<sub>2</sub> equivalent emissions of the baseline project (without CO<sub>2</sub> capture). The cost of this CO<sub>2</sub> capturing technology is very high. Based on the above elements, it is concluded that CO<sub>2</sub> capture with the current state-of-the-art MEA technology is not justified at this time”.<sup>73</sup>

INEOS cites three specific drawbacks: 1) No mature technology exists to capture the low levels of CO<sub>2</sub> flue gases; 2) There is no guarantee for hydrogen or CO<sub>2</sub> from off-taker customers or technologies, and; 3) The evolution in carbon prices under the EU Emission Trading System is not well aligned with project economics.<sup>74</sup> INEOS estimates that it will take another decade before an offset strategy including carbon capture would be viable.<sup>75</sup>

The demonstrations and projects so far raise critical questions for the direction of the energy transition that will affect Australia and most other governments. The primary purpose of CCS is to serve as a climate solution, an emissions reduction technology that enables energy users to continue to access fossil fuels including coal, oil and gas. The technology is part of a menu of options proposed to address specific gaps in sustainable models to produce electricity, transportation, petrochemicals and agricultural chemicals.

One analysis relied upon by the Australian government makes clear that the private sector is unlikely to be willing to absorb all the costs of a CCS system.<sup>76</sup> The costs now, and even perhaps into the future, are too great. The balance sheets for carbon storage pose particular financial challenges. The main point is that CCS may require a permanent, ongoing subsidy. As the energy transition proceeds, there will be more choices like this one. CCS requires large, long-term subsidies to be more broadly accepted as a viable climate solution.

<sup>72</sup> P. Luis. [Use of monoethanolamine \(MEA\) for CO<sub>2</sub> capture in a global scenario: Consequences and alternatives](#). *Materials and Process Engineering*, 380:93-97. February 15, 2016.

<sup>73</sup> INEOS EIA, Section 14.4.2.1.1 CO<sub>2</sub> Capture Project ONE/Conclusion. For complete context, see Section 14 Climate including Section 14.4.2.1.1. (English Translation Proprietary).

<sup>74</sup> *Ibid.*

<sup>75</sup> INEOS EIA, Conclusion, Section 14.5.4.

<sup>76</sup> M. Bui, *op. cit.*, pp. 1137, 1141.

***Risk 4: Australia's domestic gas demand is likely to slow in growth, and perhaps may even decline.***

Australia's domestic market and policy choices are likely to result in a decrease in domestic demand for natural gas use.

Domestically, natural gas is used principally for industrial purposes (petrochemicals, mining and metallurgy, food and tobacco, paper and pulp), residential and commercial heating, and power generation (gas-fired electricity plants).

Australia's reliance on natural gas exports as a source of economic growth has created a dysfunctional market dynamic that has generated controversy. Since 1990, the lure of LNG exports has stimulated natural gas investment in Australia. The growth of the market has resulted in an export-to-domestic consumption ratio of approximately 2:1. Due to the domination of the export market, the domestic market price of natural gas has become tied to the global price for natural gas. In today's market, this has driven prices as high as \$20 per mmbtu, but now hovers closer to \$9 per mmbtu and is expected to drop even more through 2028.<sup>77</sup>

Aside from the volatility, the Australian economy – particularly manufacturers – cannot withstand the relatively high price of natural gas.<sup>78</sup> The elevated prices of natural gas, driven by global market forces, have resulted in attempts by Australian leaders to regulate the price of natural gas. The result, a \$12 per gigajoule (GJ) cap, has created greater distortions as the reduction in residential and commercial consumers has fuelled an already robust exodus of customers.

These market dynamics have contributed to reduced demand.

Since 2014, gas demand in Australia has declined by 14%, and gas usage for electric power by 43%. The very real possibility of further demand reductions is likely; price volatility is expected to continue, and efforts by the country to reduce greenhouse gas emissions will build.<sup>79</sup>

The Australian Energy Market Operator (AEMO) recently predicted that domestic gas consumption in central and eastern Australia would decline between 36% and 52% by 2042.<sup>80</sup> In Western Australia, it forecast a 16% increase in domestic demand (excluding LNG production) in its base scenario.<sup>81</sup> The projected increase in consumption in Western Australia is materially smaller than the projected decrease in central and eastern Australia.

The paradox for Australians is that while the country is awash in natural gas domestically, consumers do not enjoy competitive pricing that would benefit households and businesses. The system ties domestic prices to an increasingly turbulent global pricing mechanism. This is unlike the U.S., where the surplus of gas due to hydraulic fracturing has reduced domestic prices and served as an

<sup>77</sup> 1 mmbtu equals 1.055 Gigajoules.

<sup>78</sup> IEEFA. [Where to next for Australian gas?](#) December 22, 2022. Also see: IEEFA. [What's fair price domestic gas? \\$12 per gigajoule is too high.](#) December 7, 2022.

<sup>79</sup> IEEFA. [Where to next for Australian gas?](#) December 22, 2022

<sup>80</sup> Australia Energy Market Operator. [Gas Statement of Opportunities.](#) March 2023. p. 26.

<sup>81</sup> Australia Energy Market Operator. [WA GSOO figures data register.](#) December 2022. Figure 9.

incentive for lower costs to manufacturers.<sup>82,83</sup> It has also proven to be an unsuccessful business model.

***Risk 5: DIPL's Middle Arm plan will strain the existing fiscal arrangement between the states and territories and the federal government in ways that are unsustainable.***

In addition to the myriad policy and resource changes that would be needed to support the Northern Territory project, the plan places pressure on the fiscal arrangement between the states and territories. States and territories rely on a revenue stream that includes the annually assessed distribution of federal dollars through revenue sharing.<sup>84</sup> The distribution of the GST revenue sharing (goods and services tax) is performed annually by the Commonwealth Grants Commission.

**Figure 7: Assessed Budgets Per Capita (excludes no worse-off payments)**



Source: Commonwealth Grants Commission. *GST Revenues Sharing Relativities*.

Note: Expenditure includes expenses and investment.

The formula balances economic and population, property value, capital spending and COVID-19 costs with the annual tax collections. Since the taxes are economically sensitive, the amount varies from year to year. The Commonwealth Grants Commission sets the annual amounts in tandem with state and Territory budget processes.

The Northern Territory's 4.9% share of the pool typically results in the highest per capita payment, due to its sparse population and the percentage of its Indigenous population.

<sup>82</sup> American Petroleum Institute. [Abundant Natural Gas has benefited consumers](#). January 11, 2021.

<sup>83</sup> Manufacturing.net. [Study: Manufacturers Will Benefit From Low Cost of U.S. Natural Gas](#). February 13, 2014.

<sup>84</sup> Commonwealth Grants Commission. [GST Revenues Sharing Relativities](#). March 14, 2023 ("GST Report").



The Northern Territory plan requires an extended period of substantial financial commitments for the project to succeed. The 2023 budget for the Northern Territory contains substantial investments in infrastructure. The budget will experience short-term deficits that are expected to be brought back into balance as the new companies and projects take off.<sup>85</sup> This is likely to place pressure on the current balance of intergovernmental transfers to the states and territories.<sup>86</sup>

To acknowledge the potential disruption this could cause, the Northern Territory plan anticipates a 10-year infrastructure package from the Australian government that would be “quarantined” from the GST process.<sup>87</sup>

Quarantined expenditures from the GST may result in an increase in Commonwealth payments to the Territory, and a decrease in the annual GST amount that is available for the NT budget.<sup>88</sup> The effects of potential changes in revenues for the Northern Territory’s annual budget remain to be seen. In addition, the broader questions of a long-term package for the Northern Territory plan are likely to affect federal budget negotiations.<sup>89</sup>

It is beyond the scope of this report to fully analyse the effects of the Northern Territory plan and its budget and any implications for Australia’s national budget. The short- and long-term revenue and expense implications are likely to be material to current and future intergovernmental budgets.

***Risk 6: Government and corporate resources are not likely to be mobilised at sufficient levels and over the period necessary for the plan to be successful. Policy changes to address significant infrastructure issues in education, environment, transportation, water management and electricity regulation are too numerous to be practical.***

The development of the Beetaloo and Barossa natural gas resources and large-scale investments in a number of new industries will require substantial physical, human and development infrastructure investments. The infrastructure needed to support a robust development project in the Northern Territory is extensive.

The lack of existing infrastructure reflects the remoteness of location. Unlike the U.S., which had an existing system of pipelines, rail and terminals, and regulatory processes as well as existing petrochemical and other off-taker industries in close proximity to oil and gas fields,<sup>90</sup> the government of Australia and its partner companies would be required to create a new system. Although the investment thesis assumes that an abundance of natural gas will support low prices for industrial development, an offsetting regime of costs puts the bottom line of both companies and corporations at risk.

<sup>85</sup> Northern Territory Government. [Budget 2023](#). May 2023. See also: Northern Territory Government, [Budget Regional Overview](#), p. 2.

<sup>86</sup> Australian Financial Review. [‘Off budget’ spending expanded for NT energy hub](#). February 27, 2023.

<sup>87</sup> [TERC Report](#), p. 92.

<sup>88</sup> [GST Report](#), pp. 31-32.

<sup>89</sup> For example, although there have been critical announcements concerning money set aside for the plan, the money is not counted in the Northern Territory’s recently released FY2023-2024 budget, pending further agreements. See: Northern Territory. [Budget Strategy and Outlook](#), *op. cit.*, p. 61.

<sup>90</sup> U.S. Department of Energy. [Ethane distribution and Storage Hub in Pennsylvania](#). November 2018.

For example, the companies that pioneer the initial wells will face considerable challenges, since much of the planned infrastructure will not be in place. The Australian government reports that the network of roads that serve the area “includes unsealed sections that are unsuited to supporting gas development, especially during the wet season”, and much of the road network “is subject to seasonal closure because of flooding.”<sup>91</sup> The major tasks of moving heavy equipment needed to build a well is difficult without paved roads. On a more mundane level, there are no shops nearby to repair or remake parts; it is a 14-hour drive from Alice Springs to Darwin.

The government acknowledges the three key gas pipelines that cross or lie near the Beetaloo Basin have limited capacity. Its Beetaloo Strategic Basin Plan reports, “Any future development is likely to rely on new or enlarged gas processing and pipeline infrastructure”.<sup>92</sup>

The physical infrastructure needs are many – including not only roads and pipelines, but also water management (see below), telecommunications and housing.

The regulatory infrastructure will also require changes in several areas. The changes it will make, and those already under way to address the country’s climate transition, require consideration of environmental oversight, new utility regulation, Native title rights, and royalty and taxation amendments.

Credit rating agencies have acknowledged the risks associated with project financing that are connected to broader hub development concepts. Standard and Poor’s has called into question the concept of petrochemical hub expansions. The credit rating agency raised questions with the efforts by Formosa, a Taiwan-based company, to expand its petrochemical investments in Louisiana in the U.S. Noting rising construction and other costs, it also pointed out that the company faced “surging pressure” from local communities. The efforts were not specific to Louisiana, but are part of a broader market trend.<sup>93</sup> Essentially, S&P Global indicated that Formosa’s pursuit of the Louisiana project would likely be credit negative.

Leaders in the Northern Territory also face the need to align the skill quality of existing workers with the needs of future businesses, and to attract additional employees. Charles Darwin University (CDU) is the principal higher education resource in the region. Like the Territory itself, it needs investment to attract a program and faculty that are aligned with the workforce demands of a more specialised, evolving industry. Attracting new employees and their families will require the combined resources of both public and private institutions at all levels. This includes a commitment to upgrade and expand the housing stock in the area.

Both the corporate and governmental sides will likely apply constant pressure to have the other partner to absorb extra costs that will be tacked onto project development balance sheets.

Given all the currently unmet infrastructure needs for a fracking build-out, the Beetaloo Strategic Basin Plan acknowledges that a “serious” challenge to meeting the full gas-drilling potential of the field is “starting production by 2025 (or earlier) to meet the expected window of maximum gas demand and potential declines in production in southern states.”<sup>94</sup> The road infrastructure is not built

<sup>91</sup> Australian Government. [Beetaloo Strategic Basin Plan](#). January 1, 2021, p. 9.

<sup>92</sup> [Ibid.](#)

<sup>93</sup> IEEFA. [S&P pushes Louisiana project cancellation as a credit boost for Formosa](#). February 24, 2022.

<sup>94</sup> [Beetaloo Strategic Basin Plan](#), p. 12.

yet. The pipeline infrastructure is not built yet. The fracking wells are not built yet. The fracking waste disposal system is not built yet. The notion of starting production by 2025 is not realistic.

Furthermore, challenges to the Barossa project point to the extensive new infrastructure required to extract gas, pipe it to shore and then process it. Human rights concerns point to the site-specific violations of these investments.<sup>95</sup> Although the costs of these assets are built into the current Santos financial plan, investors have cited the multiplicity of budget and execution risks the company faces.<sup>96</sup>

These risks all threaten to push up capital costs and undermine the profitability of the natural gas well buildout.

### ***Risk 7: Natural gas industrial expansion conflicts with Australia's net zero policy.***

Australia is a party to the Paris Agreement that seeks to limit the increase in mean global temperatures to 1.5°C by 2050.<sup>97</sup> It has now legislated both a net-zero emissions target by 2050 and a target to reduce emissions by 43% on 2005 levels by 2030.<sup>98</sup> Australia recently joined the global methane pledge, which aims to reduce global methane emissions by 30% by 2030.<sup>99</sup> Its Safeguard Mechanism policy was reformed in 2023 to put a declining cap on Australia's largest industrial emitters, leading to net zero by 2050.<sup>100</sup> As part of the reform, it was announced that "shale gas projects within the Beetaloo Basin will be required to have net-zero Scope 1 emissions from the outset."<sup>101</sup>

Northern Territory leaders want to launch a new economic development framework at the best of times and the worst of times. They seek a comprehensive economic growth catalyst for a region that has been underdeveloped. It has a sizeable supply of natural gas. In the past, this would have been widely viewed as a significant benefit, but now it is more of a mixed blessing.

Natural gas development will alter water and land use, power generation, modes of road and transport and communication, and create different kinds of employment opportunities.

The new development is linked to a business model that is connected to worldwide economic growth trends. The planners expect that growth in natural gas demand from new businesses domestically and LNG customers internationally will consume the gas from fracking in the Beetaloo sub-basin.

The lack of development has left the natural resources undisturbed, which is to the benefit of many, and also supports tourism and Indigenous culture.

The balance of sustainability and economic growth creates paradoxes.

<sup>95</sup> See: Equity Generation Lawyers, ANZ sample complaint. [Human Rights Banks](#). (Last visited June 7, 2023.)

<sup>96</sup> Snowcap. [Reform Santos](#). (Last visited June 7, 2023.)

<sup>97</sup> Australian Government, Department of Climate Change, Energy, the Environment and Water (DCCEEW). [International climate action](#).

<sup>98</sup> Australian Government, DCCEEW. [Annual Climate Change Statement 2022](#). 2022, p. 14.

<sup>99</sup> Australian Government, DCCEEW, [op. cit.](#), p. 10.

<sup>100</sup> Australian Government, DCCEEW. [Safeguard Mechanism Reforms](#). May 2023, p. 1.

<sup>101</sup> Australian Government, DCCEEW, [op. cit.](#), p. 3.

Although combustion of the methane from natural gas produces lower amounts of carbon emissions than coal, the extraction and transport of the gas typically is plagued by fugitive emissions of methane. Methane is at least 84 times more powerful as a greenhouse gas than carbon dioxide over a 20-year period.<sup>102</sup>

Any assertions about the effectiveness of methane leak detection and repair must be evaluated based on comprehensive measurements, not model estimates. The U.S., for example, relies on a federal model for estimating methane emissions from oil and gas operations,<sup>103</sup> but the model has been found to be inaccurate. Several studies have demonstrated the model falls well short of identifying methane emissions consistent with observations in the field. A 2022 study published in *Environmental Science & Technology* reported the results of a basin-wide airborne survey of methane in the New Mexico Permian Basin. It found methane emission levels to be 9.4% of total gas production, and 6.5 times higher than the U.S. Environmental Protection Agency's model would predict.<sup>104</sup> Some smaller scale studies found lower emission levels, but they are still significantly higher than the model prediction. A 2021 Stanford University study measured methane levels at rates 1.5 to two times higher than the U.S. model would predict, and noted unintentional leaks were responsible for almost half of all methane emissions in the oil and gas sector.<sup>105</sup> A 2018 study published in the journal *Science* found emission rates 60% higher than the U.S. model's estimate.<sup>106</sup>

Assertions about quality of equipment and operations also must be scrutinised carefully. An 18-month probe by the U.S. House of Representative's Committee on Science, Space and Technology of emission reduction strategies for 10 Permian Basin operators concluded, "oil and gas companies are failing to design, equip, and inform their Methane Leak Detection and Repair (LDAR) activities as necessary to achieve rapid and large-scale reductions in methane emissions from their operations."<sup>107</sup> It also expressed concern that the companies relied on outdated models to measure methane emissions instead of using direct observations.<sup>108</sup>

A new chemical or petrochemical company that manufactures ammonia, ethylene or urea from natural gas would use significant amounts of electricity. Using natural gas generators would increase the burning of fossil fuels. Australia's net-zero commitment would favour solar energy. To require solar energy as a source of electricity for the new industries, however, would reduce the potential market for gas from the Beetaloo field.

Natural gas as feedstock for petrochemical and agricultural uses faces competition from lower cost and more sustainable competitors. In the short term, natural gas will be used as feedstock. In the medium term, natural gas may be replaced by blue hydrogen – hydrogen produced from natural gas in a process that releases carbon that is captured to some extent by CCS. No sooner will new

<sup>102</sup> International Panel on Climate Change (IPCC). [AR5 Synthesis Report: Climate Change 2014](#). 2014.

<sup>103</sup> U.S. Environmental Protection Agency. [Inventory of U.S. Greenhouse Gas Emissions and Sinks](#). April 14, 2022.

<sup>104</sup> Y. Chen, et al. [Quantifying Regional Methane Emissions in the New Mexico Permian Basin with a Comprehensive Aerial Survey](#). *Environmental Science & Technology* 56(7):4317-4323. March 23, 2022.

<sup>105</sup> J. Rutherford, et al. [Closing the methane gap in U.S. oil and natural gas production emissions inventories](#). *Nature* 12(1):4715. August 5, 2021.

<sup>106</sup> R. Alvarez, et al. [Assessment of methane emissions from the U.S. oil and gas supply chain](#). *Science* 361(6398):186-188. June 21, 2018.

<sup>107</sup> U.S. House Committee on Science, Space and Technology. [Seeing CH4 Clearly: Science-Based Approaches to Methane Monitoring in the Oil and Gas Sector](#). June 2022, p. 3.

<sup>108</sup> *Ibid.*

markets become familiar with blue hydrogen than green hydrogen made of water will reduce the need for natural gas to almost zero.

Depending on the rapidity of change, the investment in the Beetaloo field could be obsolete before it becomes profitable.

Australia's leaders see the development of Beetaloo as a fail-safe for LNG export markets. The TERC report appears to assume that the pace of change will be slow, and the export potential for Australian LNG will keep Beetaloo in business by delivering gas to countries that include Japan, South Korea and China.<sup>109</sup>

The domestic economic and export demand expectations for natural gas are playing out against a backdrop of a worldwide effort to curtail emissions. Of central relevance is the announcement by the IEA that the world must no longer develop new natural gas or oil fields if it is to meet lower emission targets.<sup>110</sup> The Beetaloo development runs contrary to that policy consideration. With this type of pressure, most other countries with net-zero plans will be curtailing oil and natural gas demand. As noted above, Beetaloo and Australian natural gas generally is more expensive and the market is likely to become relatively oversupplied, leading to importers changing their buying patterns.

The business model supporting the plan is not viable financially, and the companies involved are poorly prepared to address the cost challenges.

The business model at the centre of the plan calls for fracking, a technology that has failed financially, and requires a host of infrastructure investments to protect public health and safely manage water resources. The companies that have signed on are financially unprepared to carry the project to success. A careful look at Australia's natural gas capacity demonstrates it faces strong market challenges that undermine the potential for success.

***Risk 8: The use of hydraulic fracturing is not likely to be profitable. Fracking has destroyed investor value over the long term in the United States. With a weak business sector at its core, the off-taker industries do not have a stable partner to produce a reliable, cost-competitive supply of natural gas.***

A December 2017 headline in the *Wall Street Journal* said it all: "Wall Street Tells Frackers to Stop Counting Barrels, Start Making Profits". The subhead put it even more starkly: "The shale-oil revolution produces lots of oil but not enough upside for investors".<sup>111</sup>

After several years of heady production numbers that were driving the U.S. to world leader status in oil and gas production, one of the world's leading business papers told investors something many already knew: People who had invested in fracking over the past five years had lost their money.

The frackers had burned through billions, and had few profits to show for it.

<sup>109</sup> See [TERC Report](#), p. 45-47.

<sup>110</sup> International Energy Agency. [Net Zero by 2050](#). May 2021.

<sup>111</sup> Wall Street Journal. [Wall Street tells frackers to stop counting barrels, start making profits: The shale-oil revolution produces lots of oil but not enough upside for investors](#). December 13, 2017.

The extensive use of fracking in the U.S. proved to be an innovative technological model that dramatically increased the supply of oil and gas. After decades of trial and error, however, it has yet to develop a business model that produced sustainable profits.<sup>112</sup> For most of the 2000s through the 2010s, frackers increased production at a prodigious rate, but the profits did not follow.

At the root of the problem was the strength of fracking. The technology split rocks and released significant amounts of gas and oil – so much so that markets were oversupplied. This created a demand for the low-priced gas. Many new petrochemical projects were announced in the U.S. based on the low cost of natural gas and an existing portfolio of companies, pipelines, terminals, local trading partners, established local governments and communities, a public and private educational network, and a diverse labor force.<sup>113</sup> These significant assets pushed production levels upward, outpacing demand and driving down oil and natural gas prices. The downsides were record-low market prices for oil and gas, and plummeting revenues, cash flow and profits for the producers and investors.

The production model generates substantial volumes at the onset of production, but then production drops off until wells are producing relatively small amounts. The Northern Territory 2018 inquiry noted the process required a constant supply of new wells, which altered planned footprints of oil and gas fields.<sup>114</sup>

This has logistical and environmental consequences, but also financial implications. Companies such as ExxonMobil originally saw fracking as a quick-cycle operation, one that would supply robust cash flows to help achieve cash targets and finance next cycle development.<sup>115</sup> The failure to create the cash flow due to lower prices propels companies to engage in maximum borrowing (through debt and stock issuance) to maintain the capital flow necessary to constantly invest in well replacement. When a well does not cover operations, capital expenditures and profits, it is failing financially. While the model requires constant well replacement, each new well just adds to the flow of red ink. The *Wall Street Journal* article makes the point that more barrels are being produced, but they are each losing money, and investors are losing value.

The net effect of increased supply is reduced prices – and with it, profits. The low cost of natural gas was great for the pure play petrochemical interests and transport sector but not for the bottom lines of frackers. And for the integrated, big oil majors such as ExxonMobil and Shell, the losses on upstream investments dwarfed the gains in downstream refining and petrochemicals. After a decade of losses and at the onset of the COVID-19 pandemic, oil and gas leaders largely acknowledged the failure of the industry despite the massive increase in production.<sup>116</sup> One very prominent oil executive declared fracking an “economic disaster”.<sup>117</sup>

Over the past decade, the oil and gas sector continued to lag the stock market even as U.S. oil and gas producers catapulted the country to the world’s leading oil and gas producer. During the past three years, this trend was interrupted by the dual impact of COVID-19 driving the market down

<sup>112</sup> For a long-term perspective charting the origins of the technology in the 1950’s see: Daniel Yergin. *The New Map*. New York: Penguin Press, 2020.

<sup>113</sup> The American Oil and Gas Reporter. [Marcellus and Utica: Pennsylvania Positioned As Petrochemical Powerhouse](#). May 2017.

<sup>114</sup> [2018 Inquiry](#), p. 99.

<sup>115</sup> IEEFA. [Exxon Mobil abandons goal of “quick cash” from Permian fracking](#). November 13, 2019.

<sup>116</sup> IEEFA. [Plummeting oil and gas prices leave New Mexico budget short by hundreds of millions of dollars](#). October 20, 2020.

<sup>117</sup> See comments of Scott Sheffield, CEO of Pioneer Natural Resources. Texas Monthly. [The “Mother Fracker” Reckons With the Mother of All Oil Busts](#). July 2020.

before dramatically turning around and creating an upward spiral from the beginning of 2020, until oil prices were kicked into overdrive with Russia's invasion of Ukraine. The oil price increase and subsequent substantial profits in 2022 led the oil and gas sector to the top of the stock market.

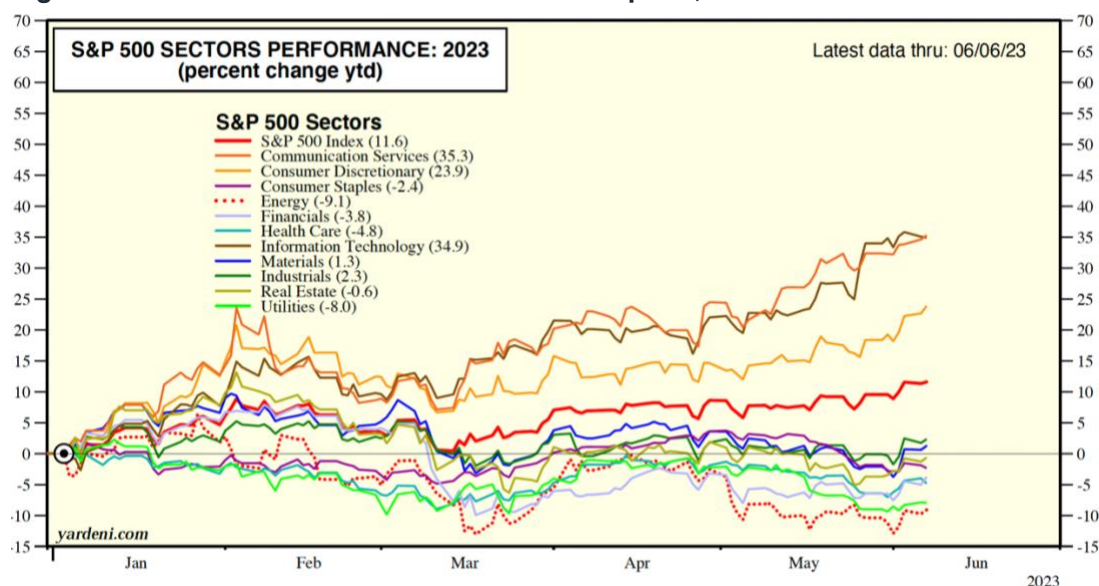
**Figure 8: Europe Brent Crude Oil Prices (2019 to present)**



Since early 2022, however, the market has been absorbing the COVID-19 and Ukraine shocks, and prices have declined. The oil and gas industry's stock values have also faltered. The two factors – COVID-19 and Ukraine – drove oil prices to a peak of almost \$125 per barrel by early 2022. As the market normalised, the price of oil has dropped, floating in the \$75 to \$85 per barrel range. The drop has sent oil and gas stock prices down.

The decline has been precipitous. For the entire first quarter of 2023, the oil and gas sector has struggled to stay out of last place in the stock market. For most of the second quarter, the sector has been in last place.

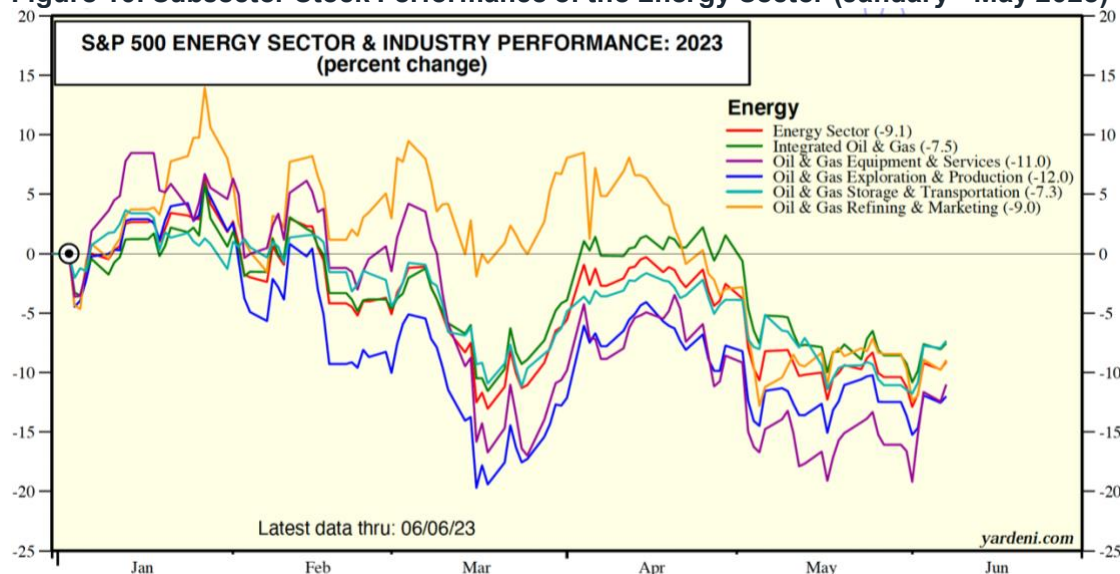
**Figure 9: Sector Performance of the S&P 500 April 6, 2023**



Source: Yardeni. S&P Sectors Performance: 2023. April 6, 2023.

The data shows two significant trends. First, the oil and gas sector as a whole lags the stock market in 2023, as it had through the past decade. Second, as Figure 10 shows, the overall decline among the industry’s poorest performers has been led by the Exploration and Production (fracking), and Oil and Gas Equipment and Services components of the energy sector. The frackers are among the poorest performing subsectors in the poorest performing industry in the stock market.

**Figure 10: Subsector Stock Performance of the Energy Sector (January - May 2023)**



Source: Standard & Poor’s.



The weak fracking business model combined with a series of other competitive pressures creates a negative outlook for the future of the oil and gas sector.<sup>118</sup> Across the oil and gas sector enterprise – including power generation, heating, transportation and petrochemicals – the industry now faces unprecedented competition. The geopolitical alignments have become even more important as the industry’s market position has weakened. Russia’s invasion of Ukraine proved to be a stark, bold reminder for the new oil and gas sector: Politics can and does drive markets, and the volatility is immense.

The U.S. market environment is different to the market environment in Australia. The financial dilemma of the fracking business model is likely to reproduce itself in Australia, but not in the same way. It is unlikely that unconventional gas exploration in the Northern Territory can produce the solid foundation needed to launch a host of new industries.

It is apparent that when the international market is overheated, Australian oil and gas prices will rise, having a particularly dramatic impact on the country’s manufacturing sector. When the industry is oversupplied, prices drop and are no longer sufficient to cover operational expenses, debt and profits for the frackers and their investors. The modern-day market for natural gas produces uncertainty and volatility.

The long-term investment trajectory of the oil and gas industry produced a decade of poor performance prior to the invasion of Ukraine. Larger companies such as ExxonMobil survived the decade, but at a cost to share value. That share value only turned around temporarily when Russia invaded Ukraine.<sup>119</sup> Small or medium-sized companies such as Tamboran, Falcon and Empire – and even larger companies such as Santos – must plan on perhaps a decade or more of losses under the Middle Arm plan.

***Risk 9: Leading gas producers in the Northern Territory are financially unprepared to address the significant investment needed to explore, drill, distribute and support infrastructure to create a hub for LNG, agricultural and petrochemical development.***

In April 2022, Santos produced a report on its climate progress that showed its emissions had increased by 94% over the previous five years.<sup>120</sup> Santos is one of the leading companies in the Beetaloo Basin. Its plan to aggressively drill for more oil and gas in opposition to the IEA’s warnings has added to the troubled outlook recently made public by investors.

Those companies with transition plans that included returning profits to shareholders and supporting technological innovation that aligned with decarbonisation goals did well.

The principal companies with permits in the Beetaloo Basin must all confront these questions. Although the companies involved in the Beetaloo Basin see the development of natural gas as an environmentally friendly investment, they all are aware that GHG emissions remain a big issue, and

<sup>118</sup> IEEFA. [Two Economies Collide: Competition, conflict and the financial case for fossil fuel divestment](#). October 13, 2022.

<sup>119</sup> IEEFA. [Oil and gas profits driven by Ukraine conflict, not financial skill](#). November 1, 2022.

<sup>120</sup> IEEFA.org, Santos 2022 [Climate change report shows emissions climbed steeply](#), April 2022

the technologies to help decarbonise the economy are not at commercial scale now, and may not be for years to come.

The main companies at the heart of natural gas development in Middle Arm – Tamboran, Santos and Empire Energy – face substantial challenges. These will require them to make large capital outlays, and perhaps forgo profits for several years. A brief look at the leading companies leads to the conclusion that none of them are well positioned to move forward. Tamboran, which has the largest holdings, has the smallest capital base. Santos, which has the largest capital base, is nevertheless overextended financially with a series of risky projects that make them an uncertain long-term partner for the Beetaloo Basin. And Empire’s viability is based on marginal operations in the U.S.

## Tamboran

Tamboran is a public natural gas company that is developing unconventional gas resources in the Northern Territory. Founded in 2009 and based in Sydney, it has held exploration permits and applications in South Australia, Western Australia, Turkey, Myanmar, the United Kingdom, Northern Ireland and Botswana. Tamboran was listed on the Australian Stock Exchange (ASX) in July 2021, having raised \$61 million at a share price of \$0.40.<sup>121</sup> The market capitalisation of Tamboran on listing was \$261 million.

Tamboran had a difficult beginning as a public company, scaling back its public offer from \$6 million to \$1 million and ending its first day of trading down 5c to \$0.35. The *Australian Financial Review* commented:

“Tamboran’s emergence as a public company has not been without hiccups after it was required by the Australian Securities and Investments Commission to amend its commentary on the gas market and provide more detail on its net zero emissions strategy in its prospectus. It also scaled back the retail part of the offer”.<sup>122</sup>

In a September 2022 joint venture with major shareholder Bryan Sheffield, Tamboran acquired Origin Energy’s 77.5% operated interest in its three Beetaloo Basin permits. Tamboran sold \$138 million of new shares to acquire Origin’s assets and fund their development.<sup>123,124</sup> The deal was pitched at \$0.21 a share.

The company’s focus is on de-risking the gas resources in the Beetaloo Basin. The working investment assumption is that Australia is experiencing a domestic shortfall in existing markets that it can fill with Beetaloo resources. The company asserts Beetaloo reserves can compete in the liquefied natural gas space over the longer term.<sup>125</sup>

Tamboran is the largest landholder in the Beetaloo.<sup>126</sup> Through a series of equity issuances and private placements, the company has amassed seven permits for exploration and production. As of

<sup>121</sup> Australian Financial Review, [Tamboran dives in ASX debut](#). July 2, 2021

<sup>122</sup> [Ibid.](#)

<sup>123</sup> Reuters, [Tamboran raises \\$89 million in big bet on Australian shale gas](#). September 19, 2022

<sup>124</sup> Tamboran Resources. [Acquisition of Origin Energy’s Beetaloo Basin Assets and Equity Raising](#). September 2022.

<sup>125</sup> Tamboran Resources. [Prospectus](#). May 2021, p. 53. (“Prospectus”)

<sup>126</sup> Tamboran Resources. [Second quarter activities report for period ended 31 December 2022](#). January 25, 2023.

December 2022, it had \$60.9 million in cash on hand but had produced no revenue from development. While some institutional investor interest exists, they are smaller names, with most of the business interest coming from industry players.

In September 2021, the stock traded at \$0.40 per share. During the week of 23 April 2023, shares had fallen to \$0.19.

**Figure 11: Tamboran Share Price (June 2021 – June 2023)**



Source: Yahoo Finance.

Tamboran acknowledged that exploration and construction costs were high in Australia, stating:

“The cost of drilling an onshore exploration well is more than two and a half times that in the US. In relation to offshore drilling costs have increased by a factor of nine in the North West Shelf over the past decade”.<sup>127</sup>

The company also has acknowledged the high cost of construction and cost overruns at several multibillion-dollar projects in recent years.<sup>128</sup>

Perhaps the most significant business event that is an indication of the market’s view of this effort was Origin’s September 2022 decision to reverse course on the Beetaloo and drop out of future exploration and production.<sup>129</sup> Although this leaves Tamboran with the lead role, Tamboran is small and backed by some experienced players in the fracking community. Its failure to attract a supermajor partner such as ExxonMobil or Chevron raises serious doubts about the project’s financial potential.

<sup>127</sup> Prospectus, *op. cit.*, p. 44.

<sup>128</sup> *Ibid.*

<sup>129</sup> Reuters. [Australia’s Origin Energy quits shale gas exploration](#). September 18, 2022.

As noted throughout this study, extracting and transporting natural gas will require substantial investments in infrastructure. This means companies involved with fracking will need to share costs with the Australian government, since no one side can carry the full weight of the physical and human infrastructure. This project will be capital-intensive and will require patience. Investors in the oil and gas space are increasingly seeking strong dividend payments, having lost out for the better part of a decade and viewing aggressive capital investment strategies with skepticism.

## Santos

Santos (AS:STO) is a global energy company with five core operations hubs. It reported a strong financial performance in the 2022 financial year, reflecting significant oil and price increases and some volume growth. Sales revenues increased 65%, rising to US\$7.8 billion while volume rose by just less than 4%.<sup>130</sup>

The company holds a 75% interest in EP 161, an exploration permit covering an area in the Beetaloo, with Tamboran holding the remaining 25%. Although test results have been promising, the company's Northern Territory holdings come at the end of a long list of projects, and EP 161 is not mentioned.<sup>131</sup>

Cooper Basin produces natural gas, gas liquids and crude oil. Volumes from the basin are sold in the domestic and international global LNG markets. Santos' Moomba CCS project reached final investment decision (FID) status in 2021, and expects first injections in 2024.

The Queensland and New South Wales project produces LNG for export to global markets through the LNG plant at Gladstone. The company has proposed the Narrabri domestic gas project in NSW, and is expanding pipeline capacity.

Papua New Guinea (PNG) – Santos's merger in 2021 with Oil Search – gives it full operational control of all of PNG's oil fields. Through several acquisitions and agreements, Santos's LNG plant near Port Moresby produced 7.8 million tonnes in 2022, shipping 114 cargos.

Northern Australia and Timor-Leste business is focused on the Bayu-Undan/Darwin (DLNG) project. DLNG produces LNG and gas liquids for export. Production from Bayu-Undan is expected to continue to decline as it nears depletion, and the company has proposed it as backfill for the Barossa project. Operations on Barossa have been suspended following a federal court decision to set aside the company's environmental plan. Santos is also moving ahead with a CCS project.

Santos is the largest producer of domestic natural gas in Western Australia. The company's Dorado project, an integrated oil and gas operation, was deferred in 2022 in favour of more development planning. The company has also started the development of a Western Australia CCS hub.

<sup>130</sup> All background information on Santos Limited comes from the company's [2022 Annual Report](#) ("Santos Annual Report") unless otherwise noted.

<sup>131</sup> [Santos Annual Report](#), p. 127. The asset is listed with no particular priority referencing.

In North America, Santos is the operator of the Pikka Unit in Alaska. The company gained it as part of its 2021 acquisition of Origin. An FID was announced in August 2022, and production is expected to begin in 2026.

In 2022, PNG revenues accounted for 43% of revenue, with the remainder derived from Santos' Australia operations. Although the company's principal assets are in Australia, Santos is looking to diversify geographically.

**Figure 12: Santos Share Price (June 2021-June 2023)**



Source: Yahoo Finance.

Santos stock value peaked at \$8.60 per share just after Russia's invasion of Ukraine. It lost value even more quickly, and traded for about \$7 a share by mid-2023. The low share price throughout 2022, during a time of record revenue, reflects market concerns about the company's longer-term outlook.

As demonstrated above, the company has taken on several significant, high-profile commitments that are reflected in the capital plan and has obligations not yet specified in future spending programs.<sup>132</sup>

With oil and gas prices ramping down from those that drove revenues up in 2022, Santos is likely to be pressured between its aggressive capital expenditures and demands from shareholders for strong dividend payments. The company's aggressive drilling strategy runs counter to the IEA's warning about new oil and gas projects. The company's approach is receiving strong criticism from investors who see several high-profile planned projects like the Alaska project and Barossa as poor strategic fits.<sup>133</sup>

<sup>132</sup> Santos Annual Report, p. 26.

<sup>133</sup> Snowcap. Letter to Santos Board of Directors. March 9, 2023.

The reform questions being raised principally to reduce capital outlays for upstream projects appear to place the Beetaloo project on the lower end of a long list. Santos, the largest partner in the Beetaloo with a market cap of US\$16.2 billion, is nevertheless an uncertain partner for the future since it is stretched financially and embroiled in disputes that need to be resolved in other parts of the Northern Territory and Australia.

## Empire Energy Group<sup>134</sup>

Empire Energy Group is an Australian-based oil and gas company. Its oil and gas assets in New York and Pennsylvania are its principal source of revenue. The major component of its exploration work is in the Beetaloo sub-basin in Australia.

The company had revenues of \$13.7 million in 2022, principally from oil and gas drilling activities in the U.S. It is in the pre-development phase in Australia, and its assets are not producing revenues. In 2022, the company benefited from a \$30 million stock issuance and a \$15 million line of credit from Macquarie Bank.<sup>135</sup> The company was also awarded a \$21 million grant from the co-operative drilling program in Australia.

Empire Energy ended 2022 with \$21 million in the bank. The surplus was higher than anticipated, since revenues spiked due to the Ukraine invasion in 2022. The company anticipates using revenues from U.S. wells to position itself for increased investments in Australia.<sup>136</sup> Empire anticipates additional progress in the Beetaloo at well EP 187 with an FID slated for later in 2023 and production in 2024-25.<sup>137,138</sup> Costs are estimated at \$20 million per well.<sup>139</sup>

The financial structure of Empire Energy is not designed to support a long-term exploration and production operation. It began in 2023 with \$21 million in the bank, but it faces at least \$4.2 million in exploration costs and declining revenues from sales in the U.S., and its year-end cash balances are expected to fall by at least \$7 million.<sup>140</sup> With gas prices volatile and tending to decline,<sup>141</sup> the company faces 2024 looking for either a new stock issuance or a loan. The recent go-ahead from the Northern Territory government for hydraulic fracturing in the Beetaloo provides some momentum, but the market share price stands at \$0.18 per share, down from the \$0.30 per share reported in 2021.<sup>142</sup>

Empire Energy seeks not only to complete one well but also to use its initial success to attract more investment in additional wells and ultimately to supply gas to the LNG market. The company's overall position is weak, since it must continue to rely on stock issuance and annual revenues from natural gas assets in the U.S. To be well positioned, the company would need significant asset valuation and – more importantly – substantial cash reserves akin to those of industry leaders.

<sup>134</sup> Empire Energy. [Gas bells are ringing](#). April 3, 2023.

<sup>135</sup> Market Herald. [Empire Energy raises \\$30 million to acquire Pangaea NT tenement](#). April 16, 2021. The stock sold for \$0.30 per share.

<sup>136</sup> Empire Energy. [2022 Annual Report](#). March 29, 2023.

<sup>137</sup> Empire Energy. [Gas bells are ringing](#). April 3, 2023.

<sup>138</sup> Empire Energy. [2022 Annual Report](#). March 29, 2023.

<sup>139</sup> Empire Energy. [Gas bells are ringing](#). April 3, 2023.

<sup>140</sup> *Ibid.*

<sup>141</sup> CME Group. [LNG Japan/Korea Market Platts](#). (Last visited June 7, 2023.)

<sup>142</sup> Australian Financial Review. [Environment stoush erupts on NT approval of fracking in Beetaloo](#). May 3, 2023.

***Risk 10: Development costs in the Northern Territory for natural gas are high. Australia is at a competitive disadvantage against the robust competition globally and domestically for the gas market.***

A newly developed Beetaloo gas asset would enter a competitive domestic and global market with every producer keenly aware of the uncertainty of the long-term market due to climate change and oversupply.

Market analysts anticipate a global 2.9% compound annual growth rate (CAGR) for natural gas through 2033.<sup>143</sup> Natural gas has long been seen by many as the cleanest fossil fuel, and its use as feedstock viewed as limitless.<sup>144</sup>

On the domestic front, Beetaloo faces competition from a long list of natural gas projects that have been announced and are at various pre-development stages. The Department of Industry, Science and Resources publishes a list of major resources in development. In 2022, the department listed 45 projects in development, with an estimated capacity of 72,376 PJ. These projects are theoretically further along in the development process than Beetaloo.<sup>145</sup> Taken together, they represent a decade of construction activity that would be spread across Australia's states and territories. Santos – one of the companies with an interest in the Beetaloo (see company discussion below) – already has four projects on the department's list that appear to be more imminent priorities than the Beetaloo.

From a financial perspective, the question is: Does Beetaloo have inherent financial characteristics that would warrant financing the project ahead of other projects where companies have already invested time and resources?

When costs are broken down by region in Australia as Figure 13 from the Qenos study shows, the breakeven cost for Beetaloo and other Northern Territory gas projects is approximately \$9 per gigajoule.<sup>146</sup>

<sup>143</sup> Persistence (proprietary).

<sup>144</sup> Massachusetts Institute of Technology. [The Future of Natural Gas](#), 2011.

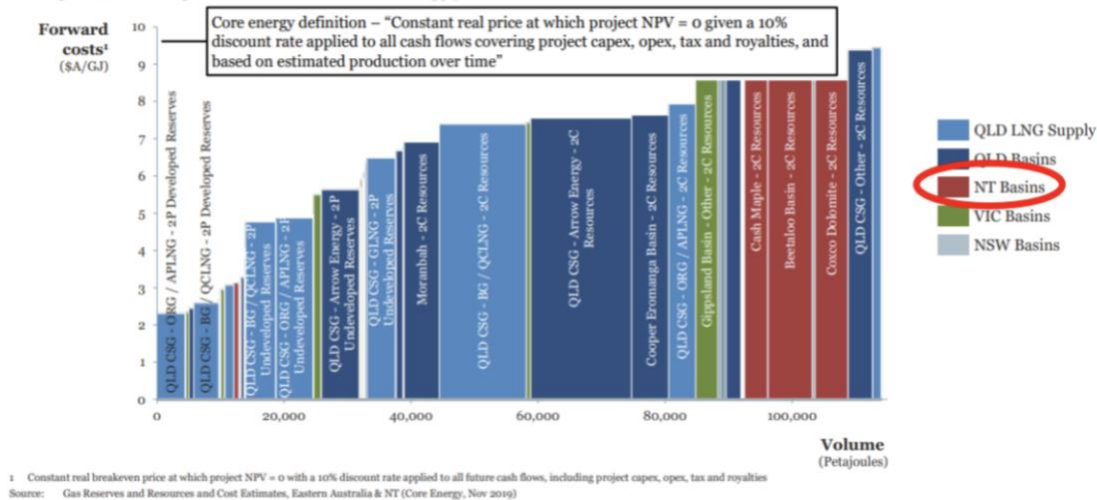
<sup>145</sup> See Appendix 1. The Beetaloo gas project is not included on Australia's list in 2022.

<sup>146</sup> Qenos, Orica and Incitec Pivot Limited, *op. cit.*, May 2021, p. 26.

**Figure 13: Australian Regional Forward Cost Comparison of Natural Gas Economies by State and Territory**

**The producer economics have been sourced from Core Energy estimates – the most economical gas has been contracted to Queensland’s three LNG trains**

2P (developed and undeveloped) and 2C reserve volumes and supply costs



Source: Qenos, Orica and Incitec Pivot Limited. May 2021, p. 26.

By this estimate, Beetaloo does not have a competitive cost advantage over other existing and potential Australian gas projects.

The same study notes that LNG consumers are shortening the terms of their procurement contracts.<sup>147</sup> Longer contract terms previously have allowed Australia to compete despite higher costs. With many importers seeking to diversify their natural gas supplies on national security grounds, the shape of contracts is changing, and a greater sensitivity to price can be expected.

As noted above, the IEA has made clear that no new oil and gas projects should be started if the world is to achieve its carbon reduction goals.<sup>148</sup> The IEA’s conclusion was reached after it surveyed several major options to determine the best path to achieving CO<sub>2</sub> emissions reductions that would limit temperature increases. The overall approach seeks not only emissions reductions, but also an energy system that is affordable and capable of ensuring economic growth.

The Beetaloo gas field plan runs counter to this guidance, and may offset many of the initiatives being taken by the Australian government to meet its net-zero commitments.

<sup>147</sup> Qenos, Orica and Incitec Pivot Limited, *op. cit.*, p. 14.

<sup>148</sup> International Energy Agency. *Net Zero by 2050*. May 2021.



***Risk 11: Regulations are not likely to protect the Australian public against the safety and health risks of fracking. The U.S. mandates failed, and polluted drinking water led to civil and criminal actions.***

The economy of the Northern Territory cannot flourish if the water resources to sustain it are contaminated. The TERC report warns that:

“Water security, including the delivery of safe and secure drinking water to urban and remote regions of the Territory, is fundamental for health, livelihood and production”.<sup>149</sup>

Yet the MASDP, with its heavy dependence on fracking, presents a substantial risk to water quality in the region.

The Beetaloo Strategic Basin Plan proposes to establish a social contract of trust with the communities to be affected by the fracking build-out, urging the local communities “to engage in good faith with gas operators, government and independent experts” to understand how Beetaloo gas development will affect their lives.<sup>150</sup> But the community cannot make informed decisions about the opportunities and risks of development if the government fails to inform them fully of the risks. Assurances of safety based on “good faith” in gas operators and government must be tempered with an understanding of what happens in the real world when that faith is disappointed.

The Northern Territory 2018 inquiry left readers with the misleading impression that the U.S. experience with fracking had been environmentally positive. It made a narrowly structured statement that, “while there have been more than one million hydraulic fracture stimulations in North America, and more than 1,300 in the Cooper Basin in SA, there has been no reported evidence of fracturing fluid moving from the fractures to near surface aquifers.”<sup>151</sup> The statement relied on outdated evidence, and it was worded in a way that could lead readers to an incorrect conclusion.

The statement relied on two sources: A 2012 paper and a 2016 U.S. EPA report.<sup>152</sup> Substantial information, as described below, has become available since then that documents fracking-related water contamination. It also implied the prime source of concern for water contamination was the potential for fracturing fluid to move directly from the fractures to near-surface aquifers, but multiple potential pathways for contamination of aquifers exist, and they have resulted in contamination. The 2016 EPA report determined contamination had occurred from such problems as injecting fracking fluid into wells lacking mechanical integrity, spills of chemicals, and improper storage or disposal of fracking wastes. The fracking industry’s practices have resulted in both air and water pollution.

Pennsylvania, for example, was eager to invite the fracking industry to exploit its shale gas. Local governments, wooed by promises of jobs and business development, generally welcomed the frackers. The industry moved in quickly and began drilling operations. Yet homeowners and local businesses soon began to complain of offensive odours and well water issues.<sup>153</sup>

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<sup>149</sup> [TERC Report](#), p. 97.

<sup>150</sup> [Beetaloo Strategic Basin Plan](#), p. 8.

<sup>151</sup> [2018 Inquiry](#), p. 77.

<sup>152</sup> [Ibid.](#)

<sup>153</sup> Pennsylvania Attorney General. [43rd Statewide Grand Jury Finds Pennsylvania Failed to Protect Citizens During Fracking Boom](#). June 25, 2020.

The state's attorney general investigated activities around areas of rural Susquehanna County. His inquiries revealed evidence of both civil and criminal violations. He turned the evidence over to a grand jury in 2018, which ultimately produced a 2020 report that recommended criminal and civil charges.<sup>154</sup>

The grand jury found the fracking development had caused methane contamination of well water used in local homes. More than half of 12 drinking water supplies showed concentrations of methane exceeding the warning range. The highest reading was 92 milligrams per litre (mg/l), above the level at which gas-contaminated water can explode.

The grand jury reported that residents described several troubling incidents. In one instance, a water well spontaneously exploded. Another resident described how kitchen tap water caught fire when a lighter was applied to it. One resident experienced sudden, violent blasts of gas and water while washing dishes. Some homeowners reported effervescence or sediment in their water, and some reported health effects such as a post-shower rash, nausea or difficulty breathing.<sup>155</sup>

The attorney general filed charges against two companies for breaking two state pollution laws.<sup>156</sup> Coterra Energy, formerly known as Cabot Oil & Gas Corporation, pleaded "no contest" to charges related to discharge of industrial wastes, including felony and misdemeanor charges. In a plea agreement, the company agreed to pay US\$16.29 million for a new regulated public water line and to cover 76 years of water bills for affected homeowners. Part of the money was to be used to provide treatment systems for the homeowners' water supplies, and provide bottled water while the public water line was under construction.<sup>157</sup> (The company now faces an effort by pension fund shareholders to bring a class action for damages related to its alleged concealing from shareholders years of environmental violations in shale gas operations.<sup>158</sup>) The other company, Range Resources Appalachia, pleaded no contest to misdemeanor water contamination charges, and was required to pay US\$150,000 in fines and contributions toward water quality protection.<sup>159</sup>

The pathways for health effects from the various chemicals used in fracking are not as easy to track as methane-in-groundwater impacts, yet the correlation of fracking to significant public health effects has been revealed by several recent studies.

Perhaps the most disturbing is a study linking fracking with increased risk of childhood acute lymphoblastic leukemia. The study by Yale University researchers found that children between the ages of 2 and 7 living in proximity to an unconventional oil or gas development were as much as two to three times likely to develop the disease. The magnitude of the association was greatest among

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<sup>154</sup> *Ibid.*

<sup>155</sup> *Ibid.* Also see: Pennsylvania Attorney General. [AG Shapiro and 43<sup>rd</sup> Statewide Grand Jury File Criminal Charges Against NEPA Fracking Company](#). June 15, 2020.

<sup>156</sup> *Ibid.*

<sup>157</sup> Pennsylvania Attorney General. [AG Shapiro Announces Plea, Public Water Line Construction for Victims of Cabot Oil & Gas](#). November 29, 2022.

<sup>158</sup> The request for class certification was filed December 5, 2022, in a Texas court. The underlying case, which survived a motion to dismiss on August 10, 2022, is [Delaware County Employees Retirement System, et al. v. Cabot Oil & Gas Corp., et al.](#), no. 4:21-cv-02045, U.S. District Court for the Southern District of Texas. Also see: Law360. [Investors Seek Class Cert. in Cabot Fracking Pollution Case](#). December 6, 2022.

<sup>159</sup> Pennsylvania Attorney General. [AG Shapiro: PA Fracking Company Pleads to Criminal Conviction in 43<sup>rd</sup> Statewide Grand Jury Investigation](#). June 12, 2020.

children living within 2km of a site and who were exposed during the perinatal period (typically, between five months before and one month after birth).<sup>160</sup>

A study by researchers from the Harvard T.H. Chan School of Public Health found elderly people living near or downwind of fracking operations, whether oil or gas, were at higher risk of early death. The researchers wrote that the study results suggested airborne pollution from such operations contributed to increased mortality.<sup>161</sup>

A 2022 study by University of Rochester and University of Kentucky researchers, funded in part by the National Institutes of Health, found an 11% to 13% increase in incidence of preterm births and low birthweight in infants exposed during gestation for every new well drilled within 1km of a drinking water source. The researchers concluded the results indicated “large social costs of water pollution.”<sup>162</sup>

A second 2022 study found the association between natural gas extraction and low birth weight varied by race. The study examined data from 28 U.S. states between 2005 and 2018. More than half the counties had natural gas extraction activities, and most of the increased activity was due to fracking. The study associated a 10% increase in natural gas drilling production in a county with a decrease in mean birthweight, by 1.48 grams generally, but with reductions of 10.19g for infants born to Black women and 2.76g for infants born to Asian women.<sup>163</sup>

The roughly 1,500 people who live within or on the border of the Beetaloo – including the communities of Daly Waters, Elliott, Jilkminggan, Larrimah, Mataranka and Newcastle Waters – would likely be at risk from the proposed fracking operations.<sup>164</sup> The Harvard study observed the risk of water contamination was highest during the pre-production period, when new wells were established.<sup>165</sup> A buildout of fracking wells in the Beetaloo pursuant to the MASPD would entail the drilling of a large number of new wells.

Fracking has been banned in France since 2011 and in Germany since 2018.<sup>166,167</sup> In 2022, the UK placed a moratorium on fracking, saying it would “not support shale extraction unless the science shows categorically that it can be done safely.”<sup>168</sup>

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<sup>160</sup> C. Clarke, *et al.* [Unconventional Oil and Gas Development Exposure and Risk of Childhood Acute Lymphoblastic Leukemia: A Case-Control Study in Pennsylvania, 2009–2017](#). *Environmental Health Perspectives* 130(8). August 17, 2022.

<sup>161</sup> Li L, *et al.* [Exposure to Unconventional Oil and Gas Development and All-cause Mortality in Medicare Beneficiaries](#). *Nat Energy*. 7(2):177-185. February 2022.

<sup>162</sup> E. Hill and L. Ma. [Drinking water, fracking, and infant health](#). *Journal of Health Economics*. 82. March 2022.

<sup>163</sup> H. Schuele, *et al.* [Associations between proximity to gas production activity and birth outcomes across the U.S.](#) *Preventive Medicine Reports*, Vol. 30. December 2022.

<sup>164</sup> The Beetaloo population and the communities within the basin are listed in the [Beetaloo Strategic Basin Plan](#), p. 8.

<sup>165</sup> E. Hill and L. Ma, [op. cit.](#)

<sup>166</sup> Scientific American. [France becomes first country to ban extraction of natural gas by fracking](#). June 30, 2011.

<sup>167</sup> Lexicology. [In brief: natural gas production in Germany](#). 28 February 2023.

<sup>168</sup> U.K. Parliament. [Shale Gas Exploration](#), Vol. 721. October 27, 2022.

In the U.S., Maryland banned fracking in 2017.<sup>169</sup> The New York Legislature banned fracking as part of its 2020 budget measure, following a 2015 EIS produced by its Department of Environmental Conservation,<sup>170</sup> and buttressed by a report from the state's Department of Health.<sup>171,172</sup>

The New York EIS concluded: “[T]he ever increasing collection of proposed mitigation measures demonstrates three essential weaknesses of the proposed program: (1) the effectiveness of the mitigation is uncertain; (2) the potential risk and impact from the proposed Action to the environment and public health cannot be quantified at this time, and (3) there are some significant adverse impacts that are simply unavoidable”.<sup>173</sup>

The Delaware River Basin Commission in 2021 banned fracking within its jurisdiction, a vast area that includes parts of Delaware, New Jersey, New York and Pennsylvania.<sup>174</sup> In addition, the states of Vermont and Washington, as well as various municipalities, have adopted fracking bans or moratoriums.<sup>175</sup>

***Risk 12: The hydraulic fracturing may pose risks to availability of water for other uses, and the management of solid waste and wastewater is likely to be costly.***

Economic development in the Northern Territory cannot succeed if the water resources to sustain it are insufficient. The TERC report notes: “A bankable investment environment requires clarity of water availability for economic use”.<sup>176</sup> The report notes that water availability is critical for the development of agriculture in the Territory, as well as other projects.<sup>177</sup> Within the Beetaloo, cattle grazing and Indigenous land practices are important uses in the area. Most of the land is classified as perpetual pastoral leasehold, the majority of which is under Native title.<sup>178</sup>

The TERC report raised concerns about the limited reliability of surface water and sporadic recharge of the arid centre of the Territory. The variable rainfall, TERC noted, limited the reliability or availability of water.<sup>179</sup>

The TERC report chided the local residents about their water use being the highest per household in Australia, complaining, “Territorians need to value and stop wasting water”.<sup>180</sup> Yet the MASDP may pose risks to the availability of water resources for homes and other purposes in the area.

Some fracking proponents have compared the consumption of water by fracking to other water uses, but that argument is misleading if it does not account for the water that is essentially lost from the

<sup>169</sup> Ann. Code of Maryland, § 14-107.1, as amended by H.B. 1325, 2017.

<sup>170</sup> New York Department of Environmental Conservation. [High-Volume Hydraulic Fracturing in NYS](#). May 2015.

<sup>171</sup> New York Department of Health. [A Public Health Review of High Volume Hydraulic Fracturing for Shale Gas Development](#). December 2014.

<sup>172</sup> Office of the Governor. [New York Budget Briefing Book: FY 2021 Executive Budget Briefing](#). 2021, p. 127.

<sup>173</sup> New York Department of Environmental Conservation, *op. cit.*, p. 12.

<sup>174</sup> Delaware River Basin Commission. [Title 18, Code of Federal Regulations, Part 440](#). February 25, 2021.

<sup>175</sup> Inside Climate News. [Map: The Fracking Boom, State by State](#). (Last visited June 1, 2023).

<sup>176</sup> [TERC Report](#), p. 97.

<sup>177</sup> [Ibid.](#)

<sup>178</sup> [Beetaloo Strategic Basin Plan](#), p. 8.

<sup>179</sup> [TERC Report](#), p. 97.

<sup>180</sup> [Ibid.](#)

local cycle. An analysis conducted of water consumption and wastewater impacts of shale gas wells in Pennsylvania noted:

“Consumptive water use refers to the water evaporated during production, lost underground or embodied in a product; it results in a net loss of water in the watershed where the water originates and reduces the water availability of that region”.<sup>181</sup>

The 2018 inquiry and the Beetaloo Strategic Basin Plan both estimate that between 50% and 80% of the water injected in a well for fracking remains in the ground.<sup>182</sup> A study by researchers at the U.S. Geological Survey (USGS) estimated that between 60% and 95% of the water used was lost into the formation,<sup>183</sup> or essentially removed from the local usable-water cycle. Unlike most industrially used water, it will not be cleaned and discharged to surface waters. If it does not migrate upwards, it is effectively gone.

The percentage of fracking water that returns to the surface during the first few weeks to months after fracking has occurred, extracted together with the gas, is known as flowback water. The 2018 inquiry and Beetaloo Strategic Basin Plan estimate the flowback water to comprise 20% to 50% of the fracking water.<sup>184</sup> The USGS researchers rely on an estimate of 5% to 40%.<sup>185</sup> Planners should assume the U.S. estimate would be mirrored for Beetaloo wastewater recycling and disposal planning purposes.

Reuse of fracking water is a potential option, and the 2018 inquiry states that the plan to use multi-well pads to extract the gas will “facilitate reuse of water to drill and fracture subsequent wells on the well pad”.<sup>186</sup> But the fracking water system is not a closed loop. Although the amount of flowback water that can be recycled has been estimated at roughly 90% to 95%,<sup>187</sup> the volume of flowback water is generally much smaller than the total volume needed for reuse. As the Commonwealth Scientific and Industrial Research Organisation (CSIRO) observed in a 2018 report on shale gas, reuse of wastewater “can reduce, but not eliminate” the amount of fresh water needed for fracking.<sup>188</sup> Also, the CSIRO report explains, certain contaminants or suspended solids in flowback water can impair hydraulic fracturing.<sup>189</sup>

The Beetaloo Strategic Basin Plan predicts that well drilling requires 1 to 2 million litres (ML) of water, and that each hydraulic fracturing stage requires another 1-2ML of water, depending on the extent to which fracking water is recovered and reused.<sup>190</sup> The 2018 inquiry did not predict the likely scale of shale gas development, but noted that estimates provided by Origin, Santos and Pangaea suggested that roughly 1,000 to 1,200 wells could be constructed and arranged on approximately

<sup>181</sup> M. Jiang, *et al.* [Life Cycle Water Consumption and Wastewater Generation Impacts of a Marcellus Shale Gas Well](#). *Environmental Science and Technology* 49:13059-13066. 2015.

<sup>182</sup> [2018 Inquiry](#), p. 9. Also see [Beetaloo Strategic Basin Plan](#), p. 11.

<sup>183</sup> T. Gallegos, *et al.* [Hydraulic fracturing water use variability in the United States and potential environmental implications](#). *Water Resource Res.* 51(7) July 2015.

<sup>184</sup> [2018 Inquiry](#), p. 9. Also see [Beetaloo Strategic Basin Plan](#), p. 11.

<sup>185</sup> T. Gallegos, *op. cit.*

<sup>186</sup> [2018 Inquiry](#), p. 9.

<sup>187</sup> M. Jiang, *op. cit.*

<sup>188</sup> CSIRO. [Assessment of scientific knowledge of shale gas and shale oil potential impacts](#), p. 75. (“CSIRO Report”). July 2018.

<sup>189</sup> *Ibid.*

<sup>190</sup> [Beetaloo Strategic Basin Plan](#), p. 11. Also see: [2018 Inquiry](#), p. 9. The 2018 inquiry noted the most recent long horizontal wells in the United States have required 30-40 fracturing stages, and this is likely to be analogous to shale gas development in the Northern Territory, although the number of fracturing stages may be fewer, perhaps at least 20 stages per well.

150 pads over the next 25 years.<sup>191</sup> Based on a feasibility development scenario, the 2018 inquiry estimated that such a scale and configuration of development would require a total of 20,000-60,000ML of water over 25 years, ranging on an annual basis from 2,500ML to a peak of 5,000ML.<sup>192</sup>

The figure might be an underestimate. A Carnegie Mellon University study estimated the amount of water required to successfully construct and fracture a well could range from 2.6ML to 21ML.<sup>193</sup> The USGS researchers analysed water use of oil and gas wells drilled between 2000 and 2014, and concluded the highest average annual hydraulic fracturing water usage, generally in shale-gas areas, ranged from 10ML to 36.6 ML per well.<sup>194</sup>

The 2018 inquiry suggested the risk of a local drawdown of groundwater for Beetaloo purposes affecting the ability of communities, agricultural/pastoral or other uses to access water would be “low” if the drawdown site was beyond 1km from a gas bore field.<sup>195</sup> It noted, however, that available information was limited. The panel cautioned that more analysis was needed, stating it had concluded, “there is insufficient information to permit a full assessment of the risks to groundwater resources from any shale gas industry established in the Beetaloo Sub-basin”, and recommended further assessment of the groundwater resources before more production approvals were granted for onshore shale gas activities.<sup>196</sup>

Treatment of the industrial wastewater – which includes both flowback water and “produced” water that leaks from the shale layer after the flowback period, and typically is saline – presents problems.<sup>197</sup> The CSIRO report notes the Northern Territory has no industrial facility to treat and dispose of fracking wastewater.<sup>198</sup> CSIRO cautioned that “the transport of wastewater across the landscape had resulted in contamination events, caused either by accident or by deliberate intent”.<sup>199</sup> The 2018 inquiry warned:

“...the discharge of shale gas wastewaters to the largely temporary surface waters in the semi-arid and arid regions of the NT is problematic in that it is difficult to predict the behaviour of any contaminants discharged into such systems. In particular, the variable nature of these temporary streams and waterholes would make it likely that discharged contaminants would be trapped in the waterholes left after the temporary streams ceased to flow”.<sup>200</sup>

The panel recommended that discharge of fracking wastewater– whether treated or untreated – to drainage lines, waterways, temporary stream systems or waterholes not be allowed.<sup>201</sup>

<sup>191</sup> [2018 Inquiry](#), p. 14. The 2018 Inquiry noted that the industry estimates were “considerably smaller than the estimates provided by DPIR. *Ibid.*”

<sup>192</sup> [2018 Inquiry](#), p. 17.

<sup>193</sup> M. Jiang, *op. cit.*

<sup>194</sup> T. Gallegos, *op. cit.*

<sup>195</sup> [2018 Inquiry](#), p. 18.

<sup>196</sup> [2018 Inquiry](#), p. 18.

<sup>197</sup> [2018 Inquiry](#), p. 9.

<sup>198</sup> [CSIRO Report](#), p. 75.

<sup>199</sup> [CSIRO Report](#), p. 76, citing Laeur et al. 2016, Maloney et al. 2017, Kell 2011, and a submission to CSIRO by the Seed Indigenous Youth Climate Network.

<sup>200</sup> [2018 Inquiry](#), p. 20.

<sup>201</sup> *Ibid.*

Wastewater disposed by underground injection is effectively lost from the local water cycle, and may pose risks. Regarding deep well injection in U.S. locations, the USGS researchers have cautioned that disposal of wastewater into deep wells after hydraulic fracturing “has triggered seismicity in some areas”.<sup>202</sup> The Delaware River Basin Commission adopted a rule prohibiting the discharge of wastewater from high-volume fracking to lands or waters within the basin.<sup>203</sup>

The CSIRO report observed the Northern Territory had no known potential onshore sites for reinjecting flowback or produced water into conventional hydrocarbon formations outside the Amadeus Basin.<sup>204</sup> The 2018 inquiry urged against allowing reinjection of fracking wastewater into deeper aquifers or conventional reservoirs unless an investigation found the risks could be managed.<sup>205</sup>

When wastewater is not injected underground, it is typically trucked to a waste facility. Solid waste – drill cuttings from well construction plus drilling muds and sand or other material mixed with fracturing fluid to hold fractures open that return to the surface after a well is fractured – is typically trucked to landfills. In addition to the direct costs of trucking and disposal, a study of wastewater and solid waste trucking from wellfields in Pennsylvania found local roads experienced the greatest amount of truck traffic and associated costs for road maintenance (US\$1.1 million to US\$1.6 million). Interstate highways experienced fewer costs (US\$300,000 to US\$1.6 million). Counties that hosted the fields experienced the most truck traffic and the highest associated roadway costs, but many counties outside the active development area also incurred trucking-related roadway repair expenses.<sup>206</sup> This potential cost must be considered for the proposed Beetaloo development.

The industrial developments contemplated by the MASDP will have water consumption and wastewater disposal needs that require evaluation as well. Dredging to accommodate shipping will also have financial costs and resource effects.

## Conclusion

The DIPL and TERC have constructed a plan that focuses on the development of a new network of industrial businesses in emerging sectors. Companies looking for places to expand are seeking public partnerships with solid, stable natural resource bases and a positive investment environment.

The Northern Territory’s plan depends on natural gas at a time when the risk of fossil fuel development faces unprecedented financial, political, and technological competition.

Although the Territory benefits from a rich supply of natural gas, it is an asset with declining value in the global market. Developing the gas field would require a sizeable long-term investment of policy and financial resources at a time when competitive market conditions and political pressures suggest a more measured approach. It would be more pragmatic to deploy resources that are available into

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<sup>202</sup> T. Gallegos, *op. cit.*

<sup>203</sup> Title 18, U.S. Code of Federal Regulations, Part 440 and Article 4 of the Commission’s Water Quality Regulations (incorporated by reference at Part 410). See [Delaware River Basin Commission. Final Rule Addressing Water Importation and Exportation & Prohibiting the Discharge of High Volume Hydraulic Fracturing Wastewater](#). December 7, 2022.

<sup>204</sup> [CSIRO Report](#), p. 77.

<sup>205</sup> [2018 Inquiry](#), p. 20.

<sup>206</sup> L. Patterson and K. O’Malley. [Transport of hydraulic fracturing waste from Pennsylvania wells: A county-level analysis of road use and associated road repair costs](#). *Journal of Environmental Management*. 181:353-362. October 1, 2016.

market opportunities that are sustainable, with benefits that do not depend solely on tumultuous global geopolitical factors.

The risk to this plan is that it offers very few local, measurable economic opportunities in the short term and a difficult path to achieve long-term objectives. The plan would require expenditures that can only be characterised at this point as large and growing against a backdrop where the hoped for are increasingly unlikely.



## Appendix I: List of Australian Natural Gas Projects From Resource Energy Major Projects<sup>207</sup>

Project	Company	State	PJ per Annum	Resource
Spartan Development	Santos	WA	0.0	Gas
Crux LNG	Shell / SGH Energy / Osaka gas	WA	239.9	Gas
Julimar-Brunello Project (Phase 2)	Woodside / KUFPEC	WA	0.0	Gas / condensate
LNG import terminal - Outer Harbor Project	Venice Energy	SA	80.0	LNG
Corvus	Santos	WA	0.0	Gas
Lockyer Deep	Mineral Resources/NorWest Energy	WA	72.8	Gas
Barossa backfill to Darwin LNG	Santos / SK	NT	0.0	Gas / condensate
Cash Maple Development	PTTEP Australasia	WA	130.0	Gas / condensate
Surat Gas Project (Phases 2-5)	Arrow Energy	QLD	146.0	Gas
Transborders Energy's Generic FLNG Solution	Transborders Energy	WA	78.0	LNG
Judith Gas Field Project	Emperor Energy Ltd	VIC	29.2	Gas
Scarborough	Woodside	WA	416.0	Gas
LNG import terminal - Geelong LNG Regasification Terminal	Viva Energy	VIC	140.0	LNG
Tipton	Arrow Energy	QLD	29.2	Gas
Vail Gas	Vintage/Metgasco/Bridgeport	QLD	9.0	Gas
Mahalo Gas project	Comet Ridge / Santos / APLNG	QLD	21.9	Gas
Greater Sunrise	Timor GAP / Woodside / Osaka Gas	NT	0.0	Gas / condensate
LNG import terminal - Newcastle GasDock	Energy Projects and Infrastructure Korea (EPIK)	NSW	110.0	LNG
Jansz-Io Compression Project	Chevron / ExxonMobil / Shell / Osaka Gas / Tokyo Gas / JERA	WA	0.0	Gas
West Erregulla (Phase 1 )	Strike Energy / Warrego Energy / Australian Gas Infrastructure Group	WA	31.8	Gas
LNG import terminal - Port Philip Bay	Vopak	VIC	120.0	LNG
Browse to North West Shelf	Woodside/ BP / PetroChina / Shell / Japan Australia LNG	WA	592.8	Gas
Waitsia (Stage 2)	Beach Energy / Mitsui	WA	91.3	Gas
Narrabri coal seam gas project	Santos / Energy Australia	NSW	73.0	Gas
Enterprise Project	Beach Energy	VIC	0.0	Gas / condensate
Surat Gas Project (Phase 1)	Arrow Energy	QLD	109.5	Gas
Gorgon (Stage 2)	Chevron / ExxonMobil / Shell / Osaka Gas / Tokyo Gas / JERA	WA	0.0	Gas
Clio-Acme	Chevron	WA	261.7	Gas / condensate
Athena Gas Plant	Cooper Energy/Mitsui Group	VIC	16.0	Gas
Arrow Bowen Gas Project	Arrow Energy	QLD	0.0	Gas
Otway (Phase 3) Development Project	Cooper Energy	VIC	120.0	Gas
Trefoil Project	Beach Energy	TAS	0.0	Gas
Kipper	Esso	VIC	50.0	Gas
Glenaras gas project	Galilee Energy Limited	QLD	34.5	Gas
Walyering	Strike Energy	WA	12.0	Gas
South Erregulla	Strike Energy	WA	0.0	Gas
Greater Western Flank (Phase-3) and Lambert Deep	BHP Petroleum / Shell/ BP/ Chevron / Japan Australia LNG	WA	0.0	Gas / condensate
Goog-a-binge	Shell QGC	QLD	31.0	Gas
Manta Gas Project	Cooper Energy	VIC	18.0	Gas / condensate
Pluto expansion (Train 2)	Woodside	WA	260.0	LNG
Pyxis Hub	Woodside	WA	0.0	Gas
LNG import terminal - Port Kembla Gas Terminal	Squadron Energy	NSW	100.0	LNG
Golden Beach Gas project	GB Energy	VIC	91.3	Gas
Equus	Western Gas	WA	104.0	Gas / condensate

<sup>207</sup> Department of Industry, Science and Resources. [Resource and Energy Major Projects: 2022](#), Database: Oil/Gas. December 13, 2022.

## Appendix II: Major New Global LNG Supply Capacity Additions

IEEFA Start Date	Country	Capacity (MMtpa)	Liquefaction Project	Liquefaction Train	Status
5/1/23	Indonesia	3.8	Tangguh LNG	Tangguh LNG T3	Under Construction
9/1/23	Mexico	1.4	Fast LNG Altamira	Fast LNG Altamira 1	Proposed
11/1/23	Republic of Congo	0.6	Congo-Brazzaville FLNG	Congo-Brazzaville FLNG 1	Under Construction
2/1/24	Senegal/Mauritania	2.5	Greater Tortue LNG	Greater Tortue FLNG 1	Under Construction
10/1/24	Russia	6.6	Arctic LNG 2	Arctic LNG 2 T1	Under Construction
3/1/25	Mexico	3	Energia Costa Azul LNG	Energia Costa Azul LNG T1	Under Construction
5/1/25	USA	3.3333	Plaquemines LNG	Plaquemines LNG T1-6	Under Construction
7/1/25	USA	5.2	Golden Pass LNG	Golden Pass LNG T1	Under Construction
9/1/25	USA	3.3333	Plaquemines LNG	Plaquemines LNG T7-12	Under Construction
12/1/25	Republic of Congo	2.4	Congo-Brazzaville FLNG 2	Congo-Brazzaville FLNG 2	Announced
1/1/26	USA	5.2	Golden Pass LNG	Golden Pass LNG T2	Under Construction
1/1/26	Canada	7	LNG Canada	LNG Canada T1	Under Construction
1/1/26	USA	3.3333	Plaquemines LNG	Plaquemines LNG T13-18	Under Construction
5/1/26	USA	3.333	Plaquemines LNG	Plaquemines LNG T19-24	Under Construction
6/1/26	USA	1.49	Corpus Christi LNG	Corpus Christi LNG Stage 3 T1	Under Construction
6/1/26	Nigeria	3.4	Nigeria LNG	Nigeria LNG T1-6 Debottleneck	Under Construction
7/1/26	USA	5.2	Golden Pass LNG	Golden Pass LNG T3	Under Construction
7/1/26	Canada	7	LNG Canada	LNG Canada T2	Under Construction
7/1/26	Australia	5	Pluto LNG	Pluto LNG T2	Under Construction
7/1/26	Qatar	8	Qatargas-RasGas	North Field East T1	Under Construction
9/1/26	USA	1.49	Corpus Christi LNG	Corpus Christi LNG Stage 3 T2	Under Construction
9/1/26	Nigeria	4.2	Nigeria LNG	Nigeria LNG T7	Under Construction
11/1/26	Qatar	8	Qatargas-RasGas	North Field East T2	Under Construction
12/1/26	USA	1.49	Corpus Christi LNG	Corpus Christi LNG Stage 3 T3	Under Construction
3/1/27	USA	1.49	Corpus Christi LNG	Corpus Christi LNG Stage 3 T4	Under Construction
3/1/27	Qatar	8	Qatargas-RasGas	North Field East T3	Under Construction
6/1/27	USA	1.49	Corpus Christi LNG	Corpus Christi LNG Stage 3 T5	Under Construction
6/1/27	Mozambique	6.44	Mozambique LNG (Area 1)	Mozambique LNG T1 (Area 1)	Under Construction
7/1/27	Qatar	8	Qatargas-RasGas	North Field East T4	Under Construction
9/1/27	USA	1.49	Corpus Christi LNG	Corpus Christi LNG Stage 3 T6	Under Construction
11/1/27	Canada	2.1	Woodfibre LNG	Woodfibre LNG T1	Under Construction
12/1/27	USA	1.49	Corpus Christi LNG	Corpus Christi LNG Stage 3 T7	Under Construction
12/1/27	Mozambique	6.44	Mozambique LNG (Area 1)	Mozambique LNG T2 (Area 1)	Under Construction
8/1/28	Russia	6.6	Arctic LNG 2	Arctic LNG 2 T2	Under Construction
8/1/30	Russia	6.6	Arctic LNG 2	Arctic LNG 2 T3	Under Construction

Source: Source: IEEFA, IHS Markit, and International Gas Union.

## About IEEFA

The Institute for Energy Economics and Financial Analysis (IEEFA) examines issues related to energy markets, trends and policies. The Institute's mission is to accelerate the transition to a diverse, sustainable and profitable energy economy. [www.ieefa.org](http://www.ieefa.org)

## About the Authors

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Tom Sanzillo, director of financial analysis for IEEFA, is the author of numerous studies on the oil, gas, petrochemical and coal sectors in the U.S. and internationally, including company and credit analyses, facility development, oil and gas reserves, stock and commodity market analysis and public and private financial structures. Sanzillo has experience in public policy and has testified as an expert witness, taught energy industry finance and is quoted frequently in the media. He has 17 years of experience with the City and the State of New York in senior financial and policy management positions. As the first deputy comptroller for the State of New York, Sanzillo oversaw the finances of 1,300 units of local government, the annual management of 44,000 government contracts, and over \$200 billion in state and local municipal bond programs as well as a \$156 billion global pension fund.

### Abhishek Sinha

Abhishek Sinha is a petrochemicals analyst, US. At IEEFA, he conducts in-depth research for our petrochemicals group analysing industry trends, regulations and company data. He identifies research topics for exploration and examines issues relevant to IEEFA's mission.

Abhishek covered the energy and chemicals sectors at Thrivent Asset Management (buy side) for five years and made significant positive contributions in all fund areas. He has wide experience in analyzing key performance indicators including, revenue drivers, operating costs and capital expenditures; along with competitive trends, leading/lagging indicators, and benchmarking analysis.

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### Suzanne Mattei

Suzanne Mattei, an attorney (Yale Law School) and consultant with Lookout Hill Public Policy Associates, has over 30 years' experience in environmental policy. As Regional Director for the NYS Department of Environmental Conservation for four years, she led permitting and enforcement in New York City. Her widely cited recent report on a proposed fracked gas pipeline in New York found flaws in proponents' arguments. As NYC Executive for the Sierra Club, her research exposed federal mismanagement of the 9/11 response; her testimony to Congress helped lead to passage of the James Zadroga Act, providing healthcare to Ground Zero workers.

**Bruce Robertson**

Bruce Robertson has been an investment analyst, fund manager and professional investor for over 36 years. He has worked with Perpetual Trustees, UBS, Nippon Life Insurance and BT. He has appeared as an expert witness before a number of government enquiries into energy issues.

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